**Naturally Fractured Tight Gas
Gas Reservoir Detection Optimization**

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Annual Report

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CONTRACT NO.:

DE-AC21-93MC30086

CONTRACTOR:

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CONTRACT NAME:

Naturally Fractured
Tight Gas Reservoir
Detection Optimization

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The work plan for October 1, 1997 to September 30, 1998 consisted of investigation of a number of topical areas. These topical areas were reported in four quarterly status reports, which were submitted to DOE earlier. These topical areas are reviewed in this volume. The topical areas covered during the year were:

- **Development of preliminary tests of a production method for determining areas of natural fracturing.** Advanced Resources has demonstrated that such a relationship exists in the southern Piceance basin tight gas play. Natural fracture clusters are genetically related to stress concentrations (also called stress perturbations) associated with local deformation such as faulting. The mechanical explanation of this phenomenon is that deformation generally initiates at regions where the local stress field is elevated beyond the regional (see Chapter 1 for description).
- **Regional structural and geologic analysis of the Greater Green River Basin (GGRB).** Application of techniques developed and demonstrated during earlier phases of the project for sweet-spot delineation were demonstrated in a relatively new and underexplored play: tight gas from continuous-type Upper Cretaceous reservoirs of the Greater Green River Basin (GGRB). The effort included data acquisition/processing, base map generation, geophysical and remote sensing analysis and the integration of these data and analyses (see Chapter 2).
- **Examination of the Table Rock field area in the northern Washakie Basin of the Greater Green River Basin.** This effort was performed in support of Union Pacific Resources- and DOE-planned horizontal drilling efforts. The effort comprised acquisition of necessary seismic data and depth-conversion, mapping of major fault geometry and analysis of displacement vectors, and the development of the natural fracture prediction (see Chapter 3).

- **Greater Green River Basin Partitioning.** Building on fundamental fracture characterization work and prior work performed under this contract, namely structural analysis using satellite and potential field data, the GGRB was divided into partitions that will be used to analyze the resource potential of the Frontier and Mesaverde Upper Cretaceous tight gas play. A total of 20 partitions were developed, which will be instrumental for examining the Upper Cretaceous play potential (see Chapter 4).
- **Partition Analysis.** Resource assessment associated with individual partitions was initiated starting with the Vermilion Sub-basin and the Green River Deep (which include the Stratos well) partitions (see Chapter 5).
- **Technology Transfer.** Tech transfer was achieved by documenting our research and presenting it at various conferences. These presentations are presented as Chapter 6, Sections A through D::
 - ▶ Innovative Applications of Petroleum Technology (Chapter 6, Section A)
 - ▶ Society of Exploration Geophysicists (Chapter 6, Section B)
 - ▶ Deep Gas Forum (Series #2)(Chapter 6, Section C)
 - ▶ International Gas Resources Conference (Chapter 6, Section D)

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Chapter 1

Development and Preliminary Tests of a Predictive Method for Natural Fracturing

It has been well demonstrated in the laboratory, theory, and field observations that secondary structures such as natural fractures accompany local deformation such as faults. Advanced Resources has demonstrated that such a relationship exists in the southern Piceance basin tight gas play. The development of natural fracture clusters are related to stress concentrations (also called stress perturbations) associated with local deformation such as faulting. The mechanical explanation of this phenomenon is that deformation generally initiates at regions where the local stress field is elevated beyond the regional. Numerous theoretical investigations support this interpretation and show the formation of secondary structures (fractures) as resulting from stress concentrations that involves both rotations in principal stress trajectories and changes in stress magnitudes.

The uncertainties of directly detecting the location of natural fractures in the subsurface using seismic attributes propels us to develop a predictive method to detect natural fractures. The genetic relationship between local faults, stress, and natural fractures provides an opportunity to predict the important criteria of location, orientation, and relative aperture of natural fractures using numerical models. Rock mechanics and a structural understanding of associated deformation provides one with the means to quantitatively assess regions for natural fractures due to local deformation. These stress concentrations can be theoretically calculated given the remote stress field, fault/fold geometry, and displacement of the local structures. Simple relationships have been investigated numerically by either boundary element or finite element analysis. In the last decade, significant advances have occurred in the field of numerical analysis and modeling of geologic deformation, principally the development of three dimensional capability. We developed, as the next logical step, a technical demonstration and application of a numerical model that can calculate stress concentrations linking the mapped structures and faults to areas of natural fracture development.

The stress concentrations associated with fault systems can be used to determine the occurrence and orientation of natural fractures formed during the tectonic process of fault deformation. Numerical models, such as the Boundary Element of Finite Element Methods, can calculate 3-D stress variations over a defined volume. In addition, once the orientation of the subsequent fracture system is known, the aperture of natural fractures can be predicted by inputting present day stress magnitudes and orientations, leading to reasonable estimates of natural fracture-related permeability. Many numerical methods exist in the academic realm as well as commercial codes related to construction or mining engineering. Two methods are commonly employed in these models are the Boundary Element Method (BEM) and the Finite Element Method (FEM). For petroleum applications, it is essential that the numerical method handle the detailed geometry of faults responsible for producing the local fracture system.

The BEM uses a displacement discontinuity procedure that explicitly delineates boundary surfaces (faults in this application) whereas the surrounding media are considered more simply. This allows one to input realistic and complex fault geometry. The requirements for a geologically realistic numerical model are twofold. First, the critical input variables must be constrained, whenever possible, by appropriate observable geologic information. For example, both fault geometry and slip

distribution along the fault plane can be determined from 3D seismic surveys and ideally, the numerical method will use this information instead of inputting estimated paleostress directions and relative magnitudes. This permits the independent determination of critical variables that affect the outcome of the model. With the BEM method stress variations can be calculated as a result of prescribed slip along the fault, eliminating the need to guess at the paleostresses that historically drove fault slip. Second, the numerical method must be robust enough to allow default or invariant input on secondary rock mechanic variables such as stiffness, friction, etc.

Advanced Resources investigated this opportunity by developing a process to predict natural fracture clusters (PNFC). We used a public-domain BEM code and applied it to the situation found at the Rulison field as well as to the Hunter Mesa/Mamm Creek field. We compared the output of the program to reservoir permeability calculated from production history to test the success of the method.

The development effort was to test the ability of the PFC Model to identify areas of high and low natural fracture intensity. Three field sites were established for this test, Figure 1-1

1. Northern Rulison Area -- a 20 section established development area where the 3-D seismic survey was located.
2. Southern Rulison Area -- a 20 section step-out development area where new wells are being drilled by Barrett Resources, Snyder Oil and Tom Brown with 2-D seismic coverage.
3. Mamm Creek/Hunter Mesa -- a 40 section area under development with 2-D seismic coverage.

Inputs to the model were kept within the realm of observation such as fault geometry (from 3-D and 2-D seismic data), fault displacement, and material properties. Output for these test cases were the location, intensity, and orientation of principal tensile stress. For these test cases, we examined the correlation of principal tensile stress concentrations with EUR and calculated permeability.

Figure 1-1
Map of the Rulison -Mamm Creek Area

The north a Rulison test area provided the most complete information on the geometry and displacements of the mapped faults due to the high-quality 3-D seismic coverage. The faults obviously continue beyond the seismic survey boundaries and their lengths were extended by the amount deemed appropriate given the displacement amounts observed in the data. At the south Rulison test area, a single 2-D seismic line provided the means to map fault geometry. A single fault appears to cut the line in section 6, T7S, R93W. This fault was assumed to be the largest reverse fault in the Rulison area since it can be observed in 2-D data. The faults were modeled as elliptical discontinuities that have varying size, displacements and spatial orientation that match closely the observed geometry, Figure 1-2. These parameters were input into the model and the resulting output of principal tensile stress was set to an observation plane at the Cameo level, Figure 1-3. When compared to the calculated permeability of the wells in the test site, Figure 1-4, it is obvious that there is a definite spatial correlation though the permeability map shows greater variations than the model output. The correlation holds when the well characteristics within the stress concentration and those that fall outside are averaged and compared, Table 1-1 and 1-2.

We examined the Mamm Creek area East of the Rulison field to determine the applicability of the concept beyond a one field analysis. The 2-D seismic data at Mamm Creek was combined with fault geometry analogs from the 3-D seismic at Rulison to establish fault style, locations and displacement for two large faults mapped at Mamm Creek - MC1 and MC2, Figure 1-5. The fault data were placed into the FFC Model to calculate the fault associated stress perturbation and two stress perturbation envelopes were established: Area 1 in the west-central portion of T7S, R93W, encompassing about 4 sections and Area 2 in the north-west portion of T7S, R92W, encompassing about 5 sections, Figure 1-6. The regions of stress concentrations correlated very well with areas of increased permeability and related production, Figure 1-7. Similar to the Rulison field test sites, we averaged the well characteristics for those located within the stress concentration and those outside the area, Table 1-3.

Figure 1-2
Fault Locations, Rulison Field

Figure 1-3
Principal Tensile Stress Concentrations, Rulison Field

Figure 1-4
Calculated Permeabilities, Rulison Field

Table 1-1
North Rulison 3-D Seismic Test Results

	Wells Inside PNFC	Wells Outside PNFC
No. Wells	14	10
Average EUR/Well	2.38 Bcf	1.37 Bcf
Average Permeability	8 μ d	4 μ d
Average Net Pay	401 ft	412 ft

Table 1-2
South Rulison 2-D Seismic Test Results

	Wells Inside PNFC	Wells Outside PNFC
No. Wells	4	17
Average EUR/Well	4.15 Bcf	1.97 Bcf
Average Permeability	42 μ	7 μ d
Average Net Pay	267 ft	282 ft

Figure 1-5
Fault Geometries and Well Locations, Mamm Creek Area

Figure 1-6
Principal Tensile Stress Concentrations, Mamm Creek

Figure 1-7
Estimated Ultimate Recovery, Mamm Creek Area

Table 1-3
Hunter Mesa/Mamm Creek 2-D Seismic Test Results

	Wells Inside PNFC	Wells Outside PNFC
No. Wells	15	16
Average EUR/Well	1.71 Bcf	0.83 Bcf
Average Permeability	13 md	6 md
Average Net Pay	189 ft	198 ft

Theoretically, locating wells using the PNFC Technology versus current practice could provide a \$40 million cost savings in the 20 section Southern Rulison Test Area (see Table 1-4).

Table 1-4
Cost-Savings of PNFC Technology

	Current Practice	PFC Technology
Target Reserves	200 Bcf	200 Bcf
Average EUR/Well	1.97 Bcf*	4.15 Bcf**
No. of Wells (for 200 Bcf of reserves)	102	48
Capital Costs (\$750,000/well)	\$76 million	\$36 million
Cost Savings		\$40 million
* Average EUR for 17 wells drilled in test area.		
** Average EUR for 4 wells drilled in PNFC area.		

Chapter 2

Regional Structural and Geologic Analysis of the Greater Green River Basin

The primary goal of work under this topic was to high-grade the greater Green River basin for exploration efforts in the Cretaceous tight gas play in southwestern Wyoming, northwestern Colorado and northeastern Utah. The ultimate objective of the regional analysis was to apply the techniques developed and demonstrated during earlier phases of the project to sweet-spot delineation in a relatively new and underexplored play: tight gas from continuous-type Upper Cretaceous reservoirs of the GGRB.

In concert with the regional analysis, detailed structural analyses were initiated in two areas within the GGRB: 1) the Jonah field, a recent discovery of previously bypassed tight-gas production from the Upper Cretaceous Lance Formation; and 2) the Stratos-1 well site, a horizontal test of the Middle Cretaceous Second Frontier Formation on the western flank of the Rock Springs uplift, where drilling operations were suspended after no significant natural fracturing was encountered during drilling of the initial, vertical, characterization well. Detailed analysis of these areas will likely provide useful insights regarding structural attributes conducive to natural fracture formation and enhanced tight gas production.

These efforts required two data types: primary data and ancillary data. Primary data, such as satellite imagery and potential field measurements, were processed and analysed. Ancillary data were collected from previous publications (e.g., geologic maps) and public domain databases (e.g., cartographic data), and were digitally reformatted and compiled. The integrated analysis of all the data, both primary and ancillary, provides a basis for delineating the structural framework of the basin, an essential part of the effort to partition the greater Green River basin.

The different types of data collected and, where appropriate, the processing procedures applied, are described in the sections below.

Landsat TM Satellite Imagery

Digital Landsat TM imagery was selected to provide the basis for mapping the regional geologic setting and internal structural characteristics of the GGRB. Eight Landsat Thematic Mapper (TM) images were purchased from the Landsat data archive at the US Geological Survey EROS Data Center (EDC). Each TM image covers a 180km x 180km area with a spatial resolution of 28.5 meters. The TM sensor simultaneously measures reflected solar radiation in six discrete spectral bands covering visible to mid-infrared wavelengths, and emitted heat energy in a single spectral band in the thermal infrared.

To maximize atmospheric and radiometric consistency across the area, images were selected to correspond closely in time. Autumn imagery was favored because the moderate sun elevation, and typically low humidity, enhances terrain features. The TM images are identified by orbital position and acquisition date as follows:

<u>Path / Row</u>	<u>Acquisition Date</u>
35/31	October 03, 1987
35/32	October 03, 1987
36/31	October 10, 1987
36/32	October 10, 1987
37/30	October 27, 1987
37/30	October 01, 1987
37/31	October 01, 1987
37/32	October 01, 1987

The October 27 duplicate of P37/R30 was purchased because a small area of forest-fire smoke appeared on the October 1 image near the southern end of the Wind River Range.

A variety of spectral band combinations was evaluated. The final combination selected was Band 7 (mid-infrared) displayed as red, Band 4 (near infrared) displayed as green, and Band 1 (blue) displayed as blue. In semiarid regions, this band combination usually provides the greatest color variation among soil types and lithologic units. It has the added advantage of providing a "natural" look, in that vegetation appears in shades of green, clouds and snow appear white, and water appears as dark blue. The images in the middle of the basin (Path 36) were interactively enhanced to emphasize geologic and terrain information, using a linear contrast stretch algorithm calibrated to minimize the effects of atmospheric scattering due to dust and haze. Digital histogram matching was performed on the adjacent images (Paths 35 and 37) to provide a consistent appearance across the study area. A standard 3x3 filter was applied to all the images to provide non-directional edge enhancement, effectively sharpening the appearance of fine terrain features and improving the structural interpretability of the final product.

The TM images were digitally georectified by developing a tight network of and image-to-map ground control points (GCPs). All of the GCPs were road intersections. Precise locations of the GCPs were derived using digital cartographic data (1:100,000 scale Digital Line Graph) available from the US Geological Survey. The images were then resampled to fit a Universal Transverse Mercator map projection (UTM Zone 12, North America 1927 datum, Clarke 1866 ellipsoid), using a second-order polynomial transform function with a least-squares linear fit to the GCPs. The controlled images were mosaicked together by picking image-to-image tie points in the overlap areas between images. The final horizontal positioning error of the mosaic was less than 100 meters (rms), with a pixel size of 50 meters.

The mosaic was used to create an image map exhibiting the entire greater Green River basin annotated with standard map information, including latitude/longitude and map grid tick marks, scale bar, north arrow, projection information, image information, state boundaries, and miscellaneous geographic features (Figure 2-1). The map was printed on heavy bond paper at 1:750,000 scale using a Hewlett-Packard DesignJet 650 large-format color inkjet printer.

Figure 2-1
LandSat TM Satellite Image Map of the Greater Green River Basin

Greater Green River Basin
 Wyoming - Colorado - Utah, U.S.A.

Satellite Image Map

LandSat Thematic Mapper (TM) controlled satellite image mosaic
 TM bands 7, 4, 1 displayed as red, green and blue, respectively
 TM imagery acquired in October 1987

Universal Transverse Mercator projection
 UTM Zone 12, Clarke 1866 ellipsoid

Horizontal control provided by USGS Digital Line Graph data

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IRS 1-C SATELLITE IMAGERY

High-resolution panchromatic image data from the Indian satellite IRS 1-C were obtained to provide greater structural detail for large-scale analyses of the Jonah field and Stratos well site. IRS 1-C images cover a 70km x 70km area with a spatial resolution of 5 meters, measuring reflected solar radiation in a single broad band spanning the blue-green to near-infrared portion of the electromagnetic spectrum. Unlike TM, the IRS panchromatic sensor is "pointable." Images are often acquired with an off-nadir viewing geometry described by the sensor's "tilt angle," or deviation from vertical. Two cloud-free images were purchased from the data archive of the commercial distributor, Space Imaging EOSAT:

<u>Area</u>	<u>Path/Row</u>	<u>Tilt Angle</u>	<u>Acquisition Date</u>
Jonah Field	256/039	-25o	October 21, 1996
Stratos-1 Well Site	256/040	+25o	March 19, 1996

Ideally, these images would have both been acquired in autumn, with a near-zero tilt angle, to better correspond with the illumination and geometric characteristics of the TM imagery. However, the IRS data archive is sparse for this area, and cloud cover was the determining factor for selecting the images.

The IRS images were georectified by picking image-to-image tie points with the controlled TM imagery, and digitally resampling to match the tie points using a second-order polynomial transform function with a least-squares fit. The final horizontal positioning error, relative to the TM mosaic, was less than 10 meters (rms).

The rectified images were contrast-enhanced and filtered to sharpen terrain detail. The IRS images were digitally merged with the full-resolution (28.5 meters), georectified TM imagery, using a cubic convolution model that multiplied the IRS and TM pixel values and rescaled the result. The merged product incorporates the spectral information contained in the TM imagery with the superior high-resolution terrain detail of the IRS imagery, providing an excellent dataset for surface geologic analysis at mapping scales recently limited to aerial photography.

Image maps were made for the Jonah and Stratos sites that correspond to their respective USGS 7.5-minute topographic quadrangles, "Stud Horse Butte" (Figure 2-2) and "Clay Buttes SW" (Figure 2-3). The maps were printed at 1:24,000 scale.

Potential Field Data

Basement structural analysis is a critical part of Advanced Resource's integrated basin evaluation technique. Basement composition and topography are revealed by measurements of the magnetic field intensity. For this study, we obtained gridded aeromagnetic residual data from the USGS.

Figure 2-2
TM/ IRS Merge Image Map of the Johan Field Area
(Stud Horse Butte Quadrangle)

Figure 2-3
TM / IRS Merge Image Map of the Stratos-1 Well Site
(Clay Buttes SW Quadrangle)

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These data have a grid spacing of 2 kilometers. We digitally reprojected the data to fit the map projection used for this project (UTM, Zone 12, NAD27), and color-coded the data to enhance abrupt gradients in the magnetic field strength (Figure 2-4). Such gradients indicate the approximate position and trend of significant structural and/or compositional boundaries in the basement. The color-coded aeromagnetic data were used to create a 1:750,000 scale mapsheet to match the TM mosaic.

Gravity field data also reveal important subsurface information. As with magnetic field strength, abrupt gradients in topographically corrected, isostatically compensated gravity measurements indicate significant regional structures that have juxtaposed rocks with contrasting densities, or caused by major vertical offset in crystalline basement. We obtained 2-kilometer gridded isostatic gravity field data from the USGS, and reprojected and color-coded it as we did the aeromagnetic data (Figure 2-5). A 1:750,000 scale mapsheet of the color-coded gravity data was created.

Other Data

Digital Line Graph (DLG) data, produced from 1:100,000 scale USGS topographic maps, were acquired for the study area. These data included transportation routes (roads, railroads, airports, pipelines, power lines), hydrography (lakes, reservoirs, rivers and streams), administrative boundaries (state and county boundaries, public lands), and the public land survey system grid (township and range). These data were used to extract GCPs for georectifying the imagery, and to provide informative reference annotation for various map products, including a complete base map of the GGRB (Figure 2-6).

A database of well locations, production and completion information was derived from the latest Petroleum Information (PI) / Dwight's data CD-ROM for the northern Rocky Mountain region. Wells were included if they were located within any of the counties underlain by the greater Green River basin, as delineated by the USGS. Well information will be used to correlate structural findings, based on the image and aeromagnetic data analysis, with patterns of production and reservoir characteristics across the basin.

Several basinwide geologic datasets were incorporated into the database, derived from maps obtained from the USGS central map library in Reston, Virginia. These datasets include structural contours, compiled from various stratigraphic horizons (Figure 2-7); major fold axes and basin-margin fault systems (Figure 2-7); boundaries of oil and gas fields (Figure 2-8); and heat flow (contours showing depth to 180° F) (Figure 2-9).

A detailed structural map was obtained for the Jonah field from a journal article (Warner, 1997). Structural contours (top of Lance Fm.) and faults were digitized from this source (Figure 2-10).

Figure 2-4
Color-Coded Aeromagnetic Anomaly Map of the Greater Green River Basin

Greater Green River Basin
 Wyoming - Colorado - Utah, U.S.A.

Aeromagnetic Anomaly Map

Aeromagnetic data from U.S. National Grids
 USGS Digital Data Series 9, 1993
 Universal Transverse Mercator projection
 UTM Zone 12, Clarke 1866 spheroid

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Figure 2-5
Color-Coded Isostatic Gravity Anomaly Map of the Greater Green River Basin

Greater Green River Basin
 Wyoming - Colorado - Utah, U.S.A.

Isostatic Gravity Residual Map

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Figure 2-6
General Location and Reference Base Map of the Greater Green River Basin

Figure 2-7
General Structure Map of the Greater Green River Basin

Figure 2-8
Gas Field Map of the Greater Green River Basin

Figure 2-9
Heat Flow Map of the Greater Green River Basin

Figure 2-10
Detailed Structure Map of the Jonah Field Basin

Structural Analysis

Basinwide structural analysis was performed to determine the variations in structural settings and styles, as the underpinning for developing a framework that would partition the basin into discrete structural blocks. The ideal approach is to integrate regional surface mapping with subsurface and basement structural information, to find structural indicators that correspond throughout the stratigraphic column. Such correspondence reveals basement-involved structures that have been persistently active throughout basin formation and deformation. These structures can exert profound influences on depositional and diagenetic facies patterns, local tectonics, stress, and fracture distribution. Once the structural analysis has been performed, production and reservoir properties from well data can be integrated with the structural framework to identify key basin features that influence natural gas production.

Satellite Image Analysis

Regional surface mapping was performed using the TM mosaic displayed at full screen resolution (~1:150,000 scale). Major surface folds were noted, but the structural mapping focused on identifying faults and fractures. On satellite imagery at this scale, faults and fractures are manifested by linear geomorphic features, or "linears": distinct, non-cultural, straight-line elements of the land surface that are revealed by abrupt variations in color, brightness, and/or texture on the imagery. Advanced Resources employs a strict geomorphic criteria to identify linears. Linears were mapped on-screen using the following classification scheme:

- Straight drainage = straight river or stream segments carrying flowing surface water.
- Straight erosional features = straight dry valley segments, washes, and rills.
- Straight scarps = straight escarpments; very closely spaced, aligned cliffs and notches.

To minimize confusion with cultural constructs, no linears smaller than 1000 meters (7.5 millimeters at 1:150,000 scale) were mapped. After the initial round of mapping, a complete second round of verification was conducted for quality control by overlaying DLG information (transportation and boundaries) to eliminate any remaining features with probable human origin (Figure 2-11).

The next phase of the image analysis required carefully examining the spatial distribution of linear features to identify geomorphic alignments that are regionally continuous expressions of aligned linears. Geomorphic alignments are broad belts of aligned and/or closely spaced linear features that represent important structural trends. In our experience, alignments of scarps are likely to result directly from faulting; erosional features are generally smaller and less continuous than the other two classes of linears, and tend to reveal regional fracture trends. Important deep-seated structural boundaries often exhibit alignments of all feature types.

Figure 2-11
Geomorphic Linear Feature Analysis of the Greater Green River Basin

Jonah Field

Linear geomorphic analysis, as described in the preceding section, was conducted for the Jonah field area using the high-resolution Landsat/IRS merge imagery corresponding to the Stud Horse Butte topographic quadrangle. Mapping was done on-screen at 1:18,000 scale (Figures 2-12 through 2-14).

At this scale, new features are mapped that do not appear clearly on the regional Landsat imagery alone. We believe these features more closely represent the actual surface traces of individual fracture planes; whereas features mapped on TM represent locally concentrated fracture sets, which may comprise individual fractures having different orientations than the observable feature. For this reason, the linears derived from basinwide analysis of the TM are considered complementary structural information to the linears derived from the high-resolution imagery.

Potential Field Analysis and Integration

Both the gravity and the aeromagnetic datasets were interpreted to discern gross basement structure (Figures 2-4 and 2-5). Steep gradients in the potential field data, caused by abrupt changes in basement composition and/or topography, indicate the presence of important basement faults or shear zones. Correlation between geomorphic alignments from the satellite imagery, and steep gradients in the potential field data, reveals persistent basement structures that influence surface geomorphology and, by inference, other physical properties throughout the intervening rock column. These important trends can comprise the boundaries of distinct structural blocks that exhibit differing fracture patterns, partitioning the basin into discrete exploration and development domains.

Once the significant geomorphic alignments were delineated, they were overlain on the color-coded aeromagnetic residual and isostatic gravity data for direct comparison with the delineated potential field gradients. Preliminary structural boundaries were determined from close correspondence between the surface and basement features.

Greater Green River Basin

Jonah Field

STUD HORSE BUTTE
WYOMING
3.5 MINUTE SERIES

Linear Geomorphic Features

- Straight escarpments, aligned cliffs or notches
- Straight valleys
- Straight streams
- Gas well

Scale 1:250,000

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Figure 2-13
Geomorphic Alignments in the Jonah Field Area

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Figure 2-14
Structural Trends Inferred from Geomorphic Alignments in the Jonah Field Area

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Chapter 3

Examination of the Table Rock Field Area

For this topical area, work focused on a local structural analysis of the Table Rock field in southwestern Wyoming. The ultimate objective of the local analysis was to apply the techniques developed and demonstrated during earlier phases of the project in the Rulison Field area of the Piceance basin for sweet-spot delineation. This effort paralleled the regional analysis of GGRB.

The following sections describe the efforts performed as part of the Table Rock local fracture prediction analysis.

Data Acquisition/Processing

This effort involved acquiring 3-D seismic data from Western Geophysical with UPR's support. Two pre-existing seismic surveys were combined, the Table Rock and Continental Divide II. Thirty-two 2-D lines were extracted from the 3-D data for post-stack depth conversion. These lines were then imported into the SeisVision interpretation platform for analysis.

Aeromagnetic data were purchased over the Table Rock area for mapping out basement trends. This provided information on possible basement control on the larger structures and to determine the depth-extent of structure, beyond the limit of seismic imaging.

Structural Analysis

Two major fault systems were mapped, the Table Rock thrust fault and a related northeast-trending strike-slip fault. It was determined from analysis of displacement vectors that the Table Rock thrust fault formed before the strike-slip fault. It was only after a critical amount of deformation occurred along the thrust fault that the strike-slip fault developed to accommodate the shortening strain. The strike-slip fault occurred along a pre-existing basement feature, as determined from the aeromag data, and is slightly oblique to the strain direction. This obliquity causes the strike-slip fault to have a reverse component in its displacement.

Natural Fracture Prediction

Using the geometry of the couple thrust-strike-slip fault system, we predicted a region of potential increased shear fracturing using a boundary-element program. Using the displacement amounts across the faults, a stress concentration is formed near the upward termination of the fault system. This stress information was then used to determine the area of fracture generation based on a Coulomb failure for shear fractures. The analysis shows an eight township areas in the Table Rock region where it can be expected that well on average will be better producers than well drilled outside this region.

The results of the effort for this topical areas were presented to DOE/FETC on June 8, 1998. That presentation is reproduced on the following pages.

Table Rock Horizontal Drilling Project: Results of Regional Structural Analysis (Task 1)

*“Developing and demonstrating high value
E&P technology for unlocking natural
gas resources in low permeability basins.”*

**A Presentation to DOE/FETC
by
Advanced Resources International, Inc.**

June 8, 1998

Project Objectives

1. *Corroborate geologic rational of drilling location and horizontal drilling orientation for UPR/DOE Table Rock Frontier test.*
2. *Determine local natural fracture clusters from detailed fault mapping that may impact the horizontal leg of the test well.*
3. *Evaluate play extent and assess resource in place.*

Project Location in the Greater Green River Basin, Wyoming

Proposed Location of Frontier Test

The Technical Program

The program is divided into three tasks:

1. Preliminary Assessment of Proposed Location
 - A. *Regional Structural Analysis*
 - B. *Regional Natural Fracture Assessment*
2. Detailed Structural Study for Horizontal Drilling Plan
 - A. *Detail Fault Mapping*
 - B. *Predict Local Natural Fracture Characteristics*
3. Regional Geologic Assessment of Play Economics
 - A. *Play Extent*
 - B. *Gas-in-Place*
 - C. *Economic Assessment*

Task 1. Preliminary Analysis

The first task involves a preliminary structural analysis that will provide the appropriate structural framework for more detailed study of the proposed drilling location and plan.

This will be accomplished by utilizing a fracture detection methodology, examination of the Govt. Union #4 core, and a preliminary stress model of a regional fault geometry of the Table Rock thrust system.

Task 1. Preliminary Analysis

1a. Characterize Natural Fractures in the Frontier Fm.

Examine Govt. Union #4 core.
Review existing publications.

1b. Analyze Imagery and Aeromagnetic Data

Integrate surface and basement structural analyses to map regional basement-involved fault trends and relate to natural fractures.

1c. Regional Mapping of 3D Seismic Data

Post-stack depth convert selected lines
Map horizons and develop structure and isopach maps
Map fault geometry for input to stress model.

1d. Perform Regional Stress Model

Using regional fault geometry, determine area(s) of enhanced natural fracturing based on stress calculations.

Natural Fractures Observed In Cores

There are three modes of fracture origin; Mode 1 is extensional and Modes 2&3 are shear. Technically shear fractures are faults as there is displacement along plane of the fracture.

Extensional Fracture

Shear Fracture

Natural Fractures Observed In Cores

The type of natural fracture observed in core is important information that will help determine the method of quantitative stress modeling.

extension fracture

shear fracture with
extensional component
(mixed mode)

shear fracture

Natural Fractures Observed In Cores

Shear(ed) fractures are identified in core by:

Natural Fractures Observed In Frontier Fm. Cores

The Govt. Union #4 core was examined to ascertain fracture character.

Types of fractures identified in the Govt. Union #4 core include:

- **Shear fractures with an extensional component exhibiting oblique-reverse slip**
- **Bitumen-filled splay fractures**
- **Bedding plane fractures**
- **Minor extensional fractures**

Govt. Union #4 Core

Frewen Deep #4 Core

The fractures reported in this core (Lorenz and Billingsley, 1996) include:

- Mineralized natural fractures (quartz and calcite) with large isolated apertures connected by thin calcite-filled fractures oriented EW (““wide fractures...change abruptly into local zones of thin...fractures”).
- “Irregular anastomosed fracture strands.”
- Bitumen-filled splay fractures (“wispy, multistranded “mares tails”).

The description of these natural fractures indicate that they are shear fractures, very similar to those observed in the Govt. Union #4.

Natural Fractures in Frontier Fm. Cores

Summary

- The natural fractures present are dominantly oblique-reverse shear fractures with an extensional component.
- Open isolated voids in core result from step-overs in shear fractures.
- The voids are connected by single fractures that are typically filled with mineral deposits.
- Open voids represent storage for gas whereas the connecting shear fractures provide the deliverability (i.e., the controlling factor in permeability).

High-Resolution Imagery and Aeromagnetic Data

High-resolution imagery and aeromagnetic data were examined to:

- **Map regional basement-related structural trends**
- **Delineate local patterns of surface fractures**
- **Identify structural partitions and any control over fracture trends.**

Imagery and Aeromagnetic Analysis

Summary

- Regional NE-SW strike-slip fault systems are basement controlled.
- NNE trending thrust faults show subtle or no correlation with basement structure.
- Surface geomorphology indicate the natural fracture pattern near the proposed location is dominated by N60W orientations - similar to the present-day orientation of maximum horizontal stress.

Table Rock and Continental Divide 3-D Seismic Surveys

Analysis objectives:

- 1) To examine history of deformation associated with fault systems and,**
- 2) To provide accurate fault geometry in spatial coordinates for use in stress model.**

Selected lines in the Table Rock and Continental Divide Phase II surveys at 1/2 mile spacing were post-stack depth converted and mapped.

Seismic Survey Lines

32 seismic lines were extracted from the 3-D data for depth conversion

3-D Seismic: Fault Mapping

The major fault systems were mapped from the basement break to the up section terminus.

The Table Rock thrust system is comprised of two major faults, a thrust fault that trends N30E and a oblique reverse-strike-slip fault that trends approximately N60E.

3-D Seismic: Fault Mapping

At the Madison level, the two faults are distinct and intersect just North of the proposed location.

Subsea structure of the Madison Fm.

3-D Seismic: Fault Mapping

At the Frontier level, the northward extension of the thrust system terminates below the Frontier Fm.

The strike-slip fault acts as an oblique tear fault accommodating strain on the thrust.

Subsea structure of the Frontier Fm.

3-D Seismic: Fault Mapping

The thrust fault only reaches the Baxter Shale level at the center of the Table Rock anticline.

The thrust system is represented by folding elsewhere.

Subsea structure of the Baxter Shale.

3-D Seismic: Fault Mapping

Profile view of
Table Rock
thrust fault
near Govt.
Union #4.

Thrust fault is
steeply dipping
and an
asymmetrical
fold is well
developed on
the hanging
wall.

Frontier

Madison

3-D Seismic: Fault Mapping

Profile near the intersection of the Table Rock thrust and the NE trending strike-slip fault just north of proposed location.

Frontier

Madison

3-D Seismic: Fault Mapping

The thrust and the NE trending strike-slip fault (to the right in this profile) are separated as one moves North in the seismic data.

3-D Seismic: Fault Mapping

Isopach maps suggest that most of the deformation associated with the thrust-strike-slip coupled system occurred post-Frontier. There may have been an earlier period of deformation in the thrust system without strike-slip movement.

Frontier to Madison Isopach

Baxter to Frontier Isopach

3-D Seismic: Fault Mapping

Summary

The deformation pattern suggests a two-stage deformation where the strike-slip fault moved once the level of contractional strain needed accommodating.

The accommodation occurred on a pre-existing basement shear zone causing the strike-slip tear to be slightly oblique to the thrust fault.

Only the connected geometry of the thrust and strike-slip faults were used in the stress model and the northern continuation of the thrust ignored.

3-D Stress Model: Objectives & Methods

Objectives : To predict location and orientations of shear fractures secondary to the Table Rock thrust system.

Methods: Numerical model is a 3-D BEM code that solves elastostatic equations for stress and displacement.

This method is limited to modeling failure due to displacement and stress perturbations along a discontinuity (fault, fracture). To capture effects of folding, one would need to include other methods such as a Finite Element Model.

3-D Stress Model: Failure Criterion

To evaluate the mechanical genesis of secondary shear fractures, the maximum Coulomb shear stress (S_c) is used as an indicator of failure.

$$S_c = ((\sigma_1 - \sigma_3)/2) * (1 + \mu^2)^{1/2} + \mu * \{(\sigma_1 + \sigma_3)/2\}$$

As compression (negative sign convention) increases from tectonic forces, the rock will fail in shear. The failure envelope is influenced by frictional forces, μ .

3-D Stress Model: Input Criteria

Inputs into model include: XYZ coordinates of fault geometry, orientation of remote stresses deduced from displacement geometry, and material properties (Poisson's ratio & shear modulus).

Remote stress orientations were calculated based on displacement amounts of the fault system. The greatest compression stress is N30W, nearly perpendicular to the thrust fault, and given a relative value of twice the other applied stresses.

Frictional component, μ , was assigned 0.6, typical of sandstones.

3-D Stress Model: Results

The proposed location is located at the northeastern extreme of the predicted shear fracture occurrence.

Predicted orientations of shear fractures is 153° (N27W) and 93° (N87W). These are nearly the same orientations found in the Govt. Union #4 core, 141°-161° and 71°-91°.

Predicted Shear Fracture Occurrence Map

Summary

- **Fault mapping of post-stack, depth-converted, Table Rock and Continental Divide Phase II 3-D seismic surveys show a connected thrust and strike-slip fault system.**
- **Preliminary regional analysis of stress perturbations associated with fault geometry indicate that the proposed location is at the northeastern extent of the perturbation.**
- **Predicted shear fracture orientations are N27W and N87W.**

Implications

- Using the situation at Govt. Union #4 as an analog and the geometry of the major fault systems, the regional extent of shear fracture occurrence is limited to approximately 8 sections. This is probably the worst-case scenario.
- From core observations, the open voids are connected by low permeability mineralized shear fractures.
- The NW trending shear fractures, however, have the greatest chance of being open due to present day stress.

Recommendations for Task 2

Stress model must address a more local occurrence of shear fractures due to interactions of small faults near the major thrust-strike-slip system. We recommend:

- A local area of study (one township) around proposed location.
- Depth-migrate the corresponding 3-D seismic data volume for better definition of structure.
- Map all small faults using continuity filter to enhance identification.
- Rerun stress model to capture small perturbations and identify local areas of shear fracture occurrence that may impact horizontal leg of proposed well.

Chapter 4

Basin Partitioning

Building on fundamental fracture characterization work and prior work performed under this contract, namely structural analysis using satellite and potential field data, the GGRB was divided into partitions that will be used to analyze the resource potential of the Frontier and Mesaverde Upper Cretaceous tight gas play. The GGRB partitions are shown in Figure 4-1, using townships as the unit of analysis.

A total of 20 partitions were developed, which will be instrumental for examining the Upper Cretaceous play potential. The rationale for the individual partitions (in alphabetical order) is as follows:

Cherokee Arch. The Cherokee Arch is a structurally high feature located in the southwest part of the GGRB, separating the Washakie Deep from the Sandy Wash area. The Cherokee Arch displays oblique right lateral faulting and is likely a counterpart to the Wamsutter Arch to the north for accommodating stresses across the Washakie Deep. The partition covers an area of eight townships.

Dad Dixon Platform. Located in the east-central part of the GGRB, the Dad Dixon Platform is in a foreland position relative to thrusting associated with basin-bounding Park Range. Structurally the platform dips at a relatively shallow angle toward the Washakie Deep. It sits in an equivalent structural position to LaBarge platform, although exploration maturity and established production levels are not as great. The partition covers an area of 21 townships.

East Sand Wash. Located south of the Cherokee Arch but in similar structural position to the Dad Dixon Platform, the East Sand Wash ramps toward the Sand Wash Deep. The partition is also located at the southern terminus of the upthrust Park Mountains where a tear fault likely separates the two domains. The partition displays fairly constant homoclinal dip and is lightly explored. Thirty one townships are covered by the partition.

Farson Deep. The Farson Deep sits in a foreland position to thrusting which uplifted the Wind River Mountains. The Farson Deep exhibits a strong gravity signature that is likely the result of basement structuring. Depth to the Frontier formation in the reaches over 16,000 feet (subsea). On the partition's southeast side may be bounding by a fault which separates it from the RockSprings Uplift. The Farson Deep is relatively unexplored and comprises an area of 25 townships.

Green River Deep. Located between the Moxa Arch and the Rock Springs uplift, the partition is bounded by a steep flank on the west and is fault-bounded on the east. The northern end of the partition includes the Sandy Bend Arch, a structurally high feature that separates the partition from the Farson Deep to the north. The partition, in the area of the Sandy Bend Arch, is the site of the Stratos 1 well, drilled by DOE and UPR. Northwest-trending basement faults occur interior to the partition. The partition is bounded on its southern end by the upthrust Uinta Mountains. The Green River Deep partition is a locus of basin-centered gas and is largely overpressured. Exploration maturity in the partition is relatively low. The partition covers an area of 61.5 townships.

Figure 4-1
Greater Green River Basin Partitions

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Hoback. The Hoback partition is an asymmetric foreland deep located between the upthrust Wind River Mountains to the east and the Wyoming thrust belt to the west. The axis of the deep is located adjacent to the Wind River Mountains and has a strong gravity expression. Depth to the Frontier formation in the partition is over 20,000 feet (subsea). On its southwestern side, the partition is transitional to the LaBarge Platform. The partition is lightly explored and covers an area of thirty one townships.

LaBarge Platform. The LaBarge Platform is a foreland area to the Wyoming thrust belt to the west where the thrust belt displays a left-stepping tear. The tear fault has set the partition up as a sub-regional structural high. On its south side the partition transitions to the more homoclinal shallow dip of the Moxa Arch and is surrounded by deeps on the east and northeast sides. Similar to the Moxa Arch, reservoirs of the Upper Cretaceous section in the partition are dominated by nonmarine sediments. The partition is the site of intense drilling, especially in the Mesa Verde section. It covers 39 townships.

Moxa Arch. The Moxa Arch is also foreland to the Wyoming thrust belt to the west. The partition is the site of generally shallow, southward dipping strata, gently folded into an arch. In contrast to much of the rest of the GGRB, the Upper Cretaceous section here is nonmarine and was deposited in a fluvial-dominated environment. The level of exploration for the Upper Cretaceous section in the partition is high. Reservoirs in the partition are generally normally pressured. The partition covers an area of 62 townships.

Pinedale. The Pinedale partition is the site of a foreland deep relative to the upthrusting of the Wind River Mountains. The partition shows a pronounced gravity low, but is differentiated from the Hoback and Farson deeps to the northwest and southeast, respectively, by the presence of the Pinedale anticline. The partition is the site of the Jonah field, an upfaulted, overpressured Lance Formation producer discovered in the early 1990s. Overall, the partition has had relatively little exploration activity. Twenty four townships are covered by the partition.

North Rock Springs. This partition comprises the northeast flank of the Rock Springs Uplift and displays relatively homoclinal northeast-dipping strata. The partition is separated from the Farson Deep on the northwest by a fault and ramps to the northeast into the Red Desert partition. The partition is the site of moderate exploration activity production, especially in the Mesa Verde Group. The partition covers 22 townships.

Red Desert. This partition is a steeper complement to the North Rock Springs partition. Where it abuts the southern edge of the Wind River Mountains to the north, the partition is a foreland deep and displays a gravity signature. To the northeast, the partition grades into the Red Desert Deep. Exploration activity in the partition has been moderate. The partition covers 48 townships.

Red Desert Deep. The Red Desert Deep is a foreland deep to the Rawlins Uplift. The partition shows a pronounced gravity signature and has a depth of over 18,000 feet (subsea) to the Frontier formation. Lightly explored, the partition covers 11 townships.

Rock Springs Crest. The Rock Springs Crest partition sits atop the north-south striking Rock Springs Uplift, which is bounded by late Laramide faulting on west side. The uplift displays a pronounced (high) gravity signature. Transverse, northeast-southwest trending faults are present in the crest. Because of the uplift the Upper Cretaceous section is normally pressured in this part of the GGRB. The Frontier formation is found at depths above sea level in this partition. The partition is heavily explored and comprises 24 townships.

Rock Springs East. This partition comprises the eastern and southeastern flank of the Rock Springs Uplift as it dips toward the Washakie and Red Desert areas. Moderate drilling has taken place in the partition. The Rock Springs East partition covers 21 townships.

Sand Wash Deep. The Sand Wash Deep partition is a foreland deep found at the eastern terminus of the Unita Mountains uplift. Adjacent to the uplift, in the southwest portion of the partition is the site of a pronounced gravity low. Depth to the top of the Frontier Formation is over 15,000 feet (subsea) in the deepest part of the partition. It is separated from the Washakie Deep to the north by the Cherokee Arch. The partition is immaturely explored and covers an area of 34.5 townships.

Vermilion Sub-basin. The Vermilion Sub-basin is sandwiched between the Washakie and Sand Wash deeps to the east, the Rock Springs Uplift to the northwest and the upthrust Unita Mountains to the south to which it lies in a foreland structural position. Overthrusting is present in fields (Kinney, Canyon Creek and Trail) of the partition, but overall the strata are relatively flat-lying compared to adjacent partitions. The partition is relatively heavily explored and comprises 14.5 townships.

Wamsutter Arch. The Wamsutter Arch is situated in a structurally high position relative to the Red Desert partition to the north and the Washakie Deep to the south. The arch may be the site of right-lateral oblique faulting, complementary to the Cherokee Arch. The partition comprises 12 townships and has been drilled fairly extensively.

Washakie Deep. The Washakie Deep may represent a rhombochasm between the Wamsutter and Cherokee arches. The partition displays a northeast-southwest gravity-low signature and is the site of basin centered gas. Depth to the top of the Frontier Formation in the partition reaches over 18,000 feet (subsea). The partition is lightly explored and comprises 28.5 townships.

Washakie West. This partition comprises the eastern dip flank dip flank of Rock Springs uplift transitional to Washakie Deep. It is relatively heavily explored, especially in the Mesa Verde section. The partition covers 13.5 townships.

Washakie East. The Washakie East partition comprises the steeper dip ramp into Washakie deep from the Dad Dixon Platform. Drilling activity, especially in the Mesa Verde section has been fairly heavy. The partition comprises 13 townships.

Using these partitions, analysis was begun on the resource associated with the Cretaceous tight gas play to attempt to highlight those areas that would be most prospective. As part of our ongoing analysis, the boundaries of the partitions are being modified slightly as we refine our models and concepts for the GGRB and as we examine the boundaries of the overpressured zone within the basin. Figures 2 and 3 show well penetrations of the Frontier and Mesa Verde formations. These data are being used to define transects of pressure profiles, which will be utilized to further adjust the partition boundaries. Also as part of this task, regional cross sections of the Frontier formation were made to develop an idea of the thickness variation of the formation.

Figure 4-2
Frontier Penetrations

Greater Green River Basin
Wells that Penetrate the Frontier Fm.

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- Wells that TD in the Frontier Fm.
- Wells that TD @ or deeper than the Dakota Fm.

- Basin Partition
- ▨ Transect

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Figure 4-3
Mesaverde Penetrations

Greater Green River Basin
Wells that Penetrate the Frontier Fm.

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- Wells that TD in the Mesaverde Fm.
- Wells that TD @ or deeper than the Mesaverde Fm.

Basin Partition

Transect

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Chapter 5

Partition Analysis

Section A: Examination of the Vermilion Sub-Basin Partition

The Vermilion Sub-Basin is located in the southern part of the Greater Green River Basin, foreland to the southern bounding thrust of the Unita Mountains and comprises the SE flank of the Rock Springs uplift. The southern portion of the partition displays oblique slip surface faulting that is transitional between the Unita thrusting and the Cherokee Arch. The Vermilion Sub-Basin shows no distinctive features on gravity data. Folding within the partition generally trends NE-SW, reflecting the partition's structural position relative to the Rock Springs Uplift, the Cherokee Arch and the Unita front. Folds within the partition are thrust fault bounded.

We examined two fields within the partition: Kinney and Canyon Creek (Figures 5-1 and 5-2). During the quarter, these fields were examined with respect to the overpressured Upper Cretaceous section, primarily the Frontier and Dakota sandstones. Examination of the Mesa Verde section was also initiated during the quarter but not completed.

Geological Setting. As part of our field descriptions, we researched the depositional environments and diagenesis of the Frontier Formation in an effort to differentiate the various facies present in the formation. Type logs for the Kinney and Canyon Creek fields are shown in Figures 5-3 and 5-4.

The Cretaceous Frontier Formation at Kinney and Canyon Creek Fields contains marine shale, offshore sand bars, fluvial deposits and coastal marine sandstones which were deposited along the western shoreline of the Cretaceous Interior Seaway during middle Turonian time (92 - 89 M.Y.). The clastic sediments of the Frontier Formation were derived from emerging uplifts in Idaho and western Utah and were transported eastward through an extensive fluvial system in central Utah and western Wyoming.

The basal part of the Frontier Formation consists of several hundred feet of marine shale beds, which were deposited on a shallow marine shelf. This section overlies the Cenomanian-age Mowry Shale along an unconformable submarine erosion surface dated at 96 M.Y. (Molenaar and Wilson, 1990). The lower Frontier shale section thins to the south onto the Cretaceous-age "Vernal High" where it is thinnest near the Uinta uplift.

The marine shelf deposits are overlain by regressive lower shoreface deposits and prograding coastal shoreline sandstone beds. The shoreface contains massive to cross bedded fine grained sandstone beds. These marine sandstones are generally sub-litharenites containing quartz sand, clays and rock fragments. These sandstones have been highly compacted and cemented with quartz, calcite and clay cements (Dutton and Hamlin, 1992). Sandstone porosity ranges from 4 to 13 % and is typically 8 to 10% (Dickinson, 1992). Permeability is generally very low (0.02 - 0.1 md). Higher permeability can be found in localized naturally fractured zones.

Figure 5-1
Frontier Formation Structure Map - Kinney-Canyon Creek Area

Figure 5-2
Frontier Formation Structure Map - Kinney-Canyon Creek Area

Figure 5-3
Type Log - Kinney Field

Figure 5-4
Type Log - Canyon Creek Field

TYPE LOG
FRONTIER AND DAKOTA FORMATIONS
CANYON CREEK FIELD
WEST WASHAKIE BASIN, WYOMING

The main Frontier marine sand is overlain by a scoured, erosional contact and a thin non-marine delta plain and fluvial section which occasionally contains coal beds and fluvial sandstone channels. This non-marine interval corresponds with the Middle Turonian sea level fall dated at 90 M.Y. (Mieras, 1992).

In some localities, Frontier sand bar deposits and shale beds overlie the non-marine delta plain deposits. These discontinuous, lenticular offshore sandstones are intensely bioturbated, and usually have poor porosity and relatively high clay content. The sand bars are conformably overlain by thick marine shales of the Upper Cretaceous Mancos (Baxter) Shale section. The Frontier sandstones in the West Washakie Basin have been buried to depths of 13,000 to 16,000 feet. Present day reservoir temperatures range from 250 - 350 deg. F. Regional thermal maturity trends indicate dry gas window conditions with vitrinite reflectance measurements ranging from 1.5 to 2.0% in this depth range (Scott, 1994). Mudlogs, drilling mud weights and pressure data indicate gas-charged overpressures in the Frontier-Mowry section at Kinney and Canyon Creek fields and throughout most of the West Washakie area.

Several basement-reverse faults and folds have created anticlinal structures within the basin-center gas system. To date, most exploration has been focused along the deep structural highs. The Frontier has been tested occasionally, but has frequently been bypassed in favor of the deeper Nugget and Dakota reservoirs and shallower Mesa Verde section.

Kinney and Canyon Creek fields are found in anticlinal structures above basement reverse faults. Structural maps were completed on the Frontier and Dakota horizons for both fields (Figures 5-5 through 5-8).

Kinney Field Description. Kinney Field is located on a Laramide-age fault-fold anticlinal structure located above a west-directed basement reverse fault on the east flank of the Rock Springs Uplift.

Gas-prone carbonaceous shales and coal beds in the Cretaceous Mancos-Frontier-Mowry shale section are buried to 12,000 to 15,000 ft deep in this region. Published %Ro data (Tyler et al, 1994) indicates $Ro = 1.0\%$ at 10,000 ft and $Ro = 2.0\%$ at 15,000 ft, indicating thermally mature conditions. These source rocks are in the gas window and have expelled gas into nearby sandstone reservoirs including the Blair (Airport) sandstones, Frontier Formation and Dakota Sandstone. Increases in drilling mud weights, gas kicks, blowouts, and DST pressure data indicate the top of a gas-charged overpressured zone at 10,000 to 11,000 ft depth in this area. The top of overpressure cuts across stratigraphy and is part of the larger basin-centered gas system in the Washakie Basin.

Figure 5-5
Kinney Field - Top Frontier Structure Map

Figure 5-6
Kinney Field - Top Dakota Structure Map

KDAKOTA.GPF

Figure 5-7
Canyon Creek Field - Top Frontier Structure Map

Figure 5-8
Canyon Creek Field - Top Dakota Structure Map

An early well was drilled to evaluate the Frontier Fm and Dakota Sandstones at the Kinney anticline (Superior Butterwick Gov't #1-18, 18-13N-99W, TD 14,060', 1957). This well was located along the crest of the structure, probably by mapping surface geology and seismic data. High mud weight (14.5 ppg) was needed to maintain control of the well in the Frontier-Mowry-Dakota section below 13,500 feet. Gas shows were encountered in the Frontier SS and several cores were cut. The cores contained quartzitic Frontier sandstone beds with no to slight visible porosity. Some coaly shale was recovered. Gas bubbles and "rainbows" were noted as well as gilsonite (pyrobitumen?) inclusions. Vertical fractures "filled with gypsum" were noted. One core was cut in the Mowry shale section. No formation tests were made of this interval. These cores are stored at the USGS Core Research Center in Lakewood, Colorado, inventory #D896.

The Dakota Sandstone was penetrated at 13,996' and two cores were cut. The cores contained hard, quartzitic sandstone with slight to no visible porosity and several vertical fractures, bleeding gas. Most of the cored Dakota sandstone beds were described as "non-porous". The well was drilled to 14,060' TD in the upper Dakota section, but did not penetrate the lower Dakota, Entrada or Nugget sandstones. No formation tests were made to evaluate the Dakota or Frontier reservoirs.

A deep wildcat well (Mountain Fuel Supply Kinney Unit #1, 18-19N-99W, TD 18,636', 1974) was drilled to evaluate the Nugget, Weber and Madison potential at the Kinney anticline. This well was probably located using seismic data and surface geology. A gas kick was encountered in the Blair Fm (Airport Sandstones) at 10,360 feet and was controlled by raising the mud weight to 11.5 ppg. This appears to be the transition into gas-charged overpressure in this area. The Frontier was penetrated at 13,400 ft with 14.9 ppg mud. The Frontier sands show high resistivity and good SP deflection on the well logs. A gas kick and blowout occurred at 13,561', just below the thick Frontier marine sandstones. The Dakota sandstone was encountered at 13,886 ft, and a thick basal conglomerate with about 8 ft of 14-20% density porosity was found at 14,055 ft, just above the Jurassic Morrison Fm. Another gas blowout was reported at 14,320' in the Morrison Fm, with gas to surface at 10-20 mmcf/d rates. This gas may have been gas from the basal Dakota channel reservoir.

Deeper drilling and testing in the Kinney #1 well discovered a significant natural gas reservoir in the fractured Nugget sandstones at 14,722-14,940 ft. Initial production from the Nugget was 13.1 mmcf/d in 1975. The Madison, Morgan and Weber reservoirs were also tested, but were found to be wet or non-productive. A dual completion was established in 1977 to produce gas from the Frontier sandstones as well as the Nugget. A packer was set at 14,620' just above the Nugget, and tubing was set at 13,240'. The Frontier was perforated at 13,405-416' and 13,444-474' and was tested at a rate of 2,837 mcf/d at 750 psi FTP, without stimulation. Records from BLM files indicate a static Frontier reservoir pressure of 9,373 psig, indicating strong overpressure at 0.70 psi/ft gradient. The reported reservoir data include average porosity of 10%, average water saturation of 58%, and average net pay of 50' in this zone. The Frontier produced 564 mmcf/g within about two years, but then ceased abruptly in late 1978. The cause of the end of production was not reported, however it may have been related to problems with liner leaks and water flows behind pipe. Poor cement jobs can occur with high BHT and depth. The water may have come from the Nugget and Entrada water drive reservoirs downhole. Two PDST's (#15 and 16) were run to evaluate liner problems. This Frontier completion was the only production from the Frontier at Kinney Field. The

well was eventually abandoned in 1992.

Following the drilling of Kinney #1, it was clear that the Superior Butterwick #1 well had not been drilled deep enough to penetrate the entire Dakota section and had missed a 'sweet spot' with high porosity in the basal Dakota conglomerate. So the well was re-entered by Mountain Fuel Supply in 1975 and was deepened into the Morrison Fm. Four Dakota sandstone beds from 14,015' to 14,209' were selectively perforated, and the well was put on production as Kinney Unit #2. Flow rates of 6716 mcf/d were reported during testing. Final shut in pressures of 4853, 6204 and 6295 psig were measured (0.44 psi/ft, normal pressure). This reservoir compartment may be connected to the approximately normally pressured Nugget reservoir system. The measured reservoir temperature was 280 F. No stimulation or fracture treatments were applied. Initial production in 1975 was 3,798 mcf/d with 31 bwpd. The well was typically produced during the winter heating season and shut in during the summer for pressure buildup. Cumulative production has been 3,664 mmcf through mid-1998.

Following the successful production tests from the Nugget at Kinney #1 and the Dakota at Kinney #2, several additional field extension wells were drilled. Kinney Unit #3 was drilled along the south-plunging nose of the anticlinal structure in 1975, but encountered the Dakota in an irregular structural position. The Entrada produced gas to surface with water recovered during testing. The Nugget was found to be tight, with no gas flows during several PDST's. A Hygel and sand frac was applied, but gas was produced at very low, sub-commercial rates (1170 mcf/d) during production tests. The Dakota flowed 500 mcf/d gas and water during testing. The Frontier was perforated and acidized, but water was recovered by swabbing. The well was plugged and abandoned in 1975. Recent mapping indicates that this well may be in a separate fault block, isolated from the rest of the field. In addition, there may have been problems with zone isolation and water flows behind pipe due to difficulties with cement jobs in the high temperature, high pressure boreholes.

Kinney Unit wells #4, #5 and #6 were more successful, and were completed to produce gas from the Dakota sandstones. Kinney #4 had initial production of 11,117 mcf/d with 0.8 bwpd, but declined rapidly and produced only 331 mcf from 1984 to 1992, when it was shut in. Kinney #5 had initial production of 5490 mcf/d and has produced 4509 mmcf through mid-1998. Kinney #6 had initial production of 8810 mcf/d and has produced 5489 mmcf through mid-1998. These wells were typically produced during the winter heating season and shut in during the summer for pressure buildups. No hydraulic fracture treatments were applied to the Dakota sandstones in these wells.

The Frontier sandstones have not been tested since Kinney #3 (1975) and Kinney #1 (1977-78 production), and are bypassed behind pipe. Well logs and core descriptions indicate quartzitic sandstone beds with 3 - 14% porosity, with variable natural fractures due to structural flexures. These tight gas reservoirs are surrounded by thermally mature, overpressured, gas-charged carbonaceous shale source rocks within a regional basin-center gas system. A recent neutron-density log (marathon VCD #3) shows strong neutron-density crossover effects in the Frontier sandstones, indicating gas saturation.

Structure maps and cross sections based on well data and field reports from BLM files indicate a sharply folded, doubly plunging anticline located above a north-south trending, west-directed basement reverse fault. The displacement on the thrust appears to be sufficient to

juxtapose Nugget sandstones in the hanging wall against overpressured, gas generating Mowry Shale source rocks in the footwall, thus charging the Nugget sandstone reservoir and basal Dakota fluvial channels. The anticlinal structure may be cut by several cross faults, creating separate reservoir compartments.

The problems encountered in Kinney #3 at the south end of the structure may be due to inadequate charge in a separate fault block. Water recoveries from the Frontier at Kinney #1 and Kinney #3 may be due to faulty cement bond and water leakage behind pipe, or may indicate complexities due to water movements along fault zones within the structure.

In 1995, the field operator, Celsius Energy (formerly Mountain Fuel Supply Company) formed an agreement with Marathon Oil Corporation to acquire 3-D seismic data across the Kinney, Canyon Creek and Trail area. Marathon has drilled two new infill wells at Kinney, based on the 3-D seismic data. Marathon Vermillion Creek Deep #1 was drilled into the Nugget Sandstone and was completed open hole, with casing set in the Morrison Formation. Initial production from the Nugget reservoir was 12,300 mcfg/d with 25 bwpd.

Another well has been drilled by Marathon in early 1998 to extend production downdip on the north-plunging nose of the structure. Marathon Vermillion Creek Deep #3 was also completed in the Nugget, open hole without casing. This well tested only 665 mcfg/day from the Nugget.

Several additional new locations have been proposed at Kinney as well as two locations to the west at Trail anticline.

Canyon Creek Field Description. Canyon Creek is a Laramide-age fault-fold anticlinal structure located above a west-vergent basement reverse fault on the east flank of the Rock Springs Uplift. The NE-SW trending basement reverse fault extends at least 12 miles under canyon Creek and Trail fields, with variable displacement. The anticlinal structure may be cut and compartmentalized by several cross faults.

Gas-prone black shales, carbonaceous shales and coal beds in the Cretaceous Mancos-Frontier-Mowry shale section are buried 12,000 to 15,000 ft deep in this region. Published %Ro data (Tyler et al, 1994) indicates $R_0 = 1.0\%$ at 10,000 ft and $R_0 = 2.0\%$ at 15,000 ft, indicating thermally mature conditions. These source rocks are in the gas window and have expelled gas into nearby sandstone reservoirs including the Blair (Airport) sandstones, Frontier Formation and Dakota Sandstone. Increases in drilling mud weights, gas kicks, blowouts, and DST pressure data indicate the top of a gas-charged overpressured zone at 10,000 to 11,000 ft depth in this area. The top of overpressure cuts across stratigraphy and is part of the larger basin-centered gas system in the Washakie Basin.

An early well was drilled to evaluate the Frontier Fm and Dakota Sandstones at Canyon Creek anticline (Stanolind Canyon Creek Unit #1, 3-12N-101W, TD 13,322', 1949). This well was located along the crest of the structure, probably by mapping surface geology and seismic data. High mud weights (14.7 - 15 ppg) were needed to maintain control of the well in the Frontier section below 12,000 feet. Gas shows were encountered in the Frontier sandstone below 12,685' and several cores were cut. The cores found poor to good porosity in quartzitic Frontier sandstones. Several thin

coal beds were penetrated. Several cores were cut in the Mowry shale section. No formation tests were made of this interval.

The Dakota Sandstone was penetrated at 13,108' and several cores were cut. The cores contained "dry" sandstone with "some" porosity and dead oil stain. The core analyses show 3 to 11 % porosity and 0.01 to 1.64 md permeability in the upper Dakota Sandstones. A "sweet spot" with unusually good core porosity and permeability (14-19%, 0.22 to 3.34 md) was discovered in the basal Dakota chert pebble sandstone at 13236-248', just above the Jurassic Morrison Formation. A gas kick occurred while drilling at 13, 264'. Liner was set at 13,185 ft in the lower Dakota, and the basal Dakota sandstone channel was evaluated with an open hole test. The zone flowed gas to surface at 1,115 mcfg per day rate, without stimulation. A shut in pressure of 5800 psi was recorded after a 14 hour buildup. If this was a shut-in tubing pressure, it indicates a possible bottom hole reservoir pressure of 7720 psi at 13, 240' = 0.58 psi/ft (moderate overpressure). The well was suspended and eventually abandoned without additional testing of the Dakota zone. Cuttings samples (and probably core chips?) from this well were donated to the AMSTRAT collection and are now stored at the USGS Core Research Center, Inventory # CZ8167.

The Frontier, Dakota, Entrada and Nugget reservoirs were penetrated in 1964 by Mountain Fuel Supply Canyon Creek #17 (3-12N-101W). this well was drilled with gas down though the Entrada sandstone where a water flow was encountered and drilling mud was added to control the water flow. 5-1/2" liner was set at 13, 845 ft just above the Nugget Sandstone. Several cores were cut in the Nugget which apparently indicated a water-saturated or non-productive reservoir. The Nugget was plugged off without testing. The Canyon Creek structural cross section, based on the 1990 Madison structure map from BLM files, indicates insufficient displacement on the reverse fault to juxtapose Nugget against Cretaceous source rocks. The Nugget reservoir is apparently un-charged and wet at this location.

The basal Dakota sandstone channel which had flowed gas to surface at the Stanolind Unit #1 well was tested in the MFS #17 in 1964 along with a Morrison sandstone, by perforations through casing (13,155-170' and 13,330-345') and a sand-diesel oil frac job ("Vis-0-Frac"). After the frac job, the well flowed gas to surface at 396 mcfg per day. Traces of frac diesel oil and ¼ barrels of water per hour, at surface flowing tubing pressure of 60 psi and csg pressure of 400 psi. The wellbore was plugged back after this low rate test in favor of better zones in the Mesaverde section uphole.

The sand and diesel oil frac technique was popular in the 1960's, but was later abandoned after formation damage studies discovered that the frac did more harm than good to most tight sandstone reservoirs. These fracs frequently created gas-oil emulsions which impaired production rates.

A deep wildcat well was drilled at Canyon Creek in 1990 (Exxon Canyon Creek Dome Unit #34, 9-12N-101W). This well penetrated the Nugget, Weber and Madison reservoirs, and evaluated the deep prospects, which were wet or non-productive. No cores or tests were made in the Frontier or Dakota reservoirs, although logs show high resistivity.

In 1995 Celsius Energy and Marathon formed an agreement for the acquisition of 3-D seismic data and drilling exploratory wells. Marathon has drilled two wells (VCD #3, VCD #1) at Kinney Field to test the Nugget. The Frontier and Dakota have been bypassed without coring or testing in

these new wells. Marathon has proposed and staked two locations at Trail anticline.

The Frontier and Dakota sandstones at Canyon Creek and Trail Fields have been penetrated by only three deep wells. The sandstones are adjacent to overpressured, gas-charged shales folded by a twelve-mile long anticlinal structure within a basin-centered gas system. Folding along the crest of the Canyon Creek anticline as well as possible cross faults may have created zones with enhanced natural fracturing, however no fracture finder logs have been run in the previous wells. The Exxon #34 well logs show strong neutron-density crossover effects in both the Frontier and Dakota sandstones, and the resistivity log shows zones with high deep resistivity. Cores from the Stanolind well contained unusually good porosity and permeability in a 'sweet spot' within the basal Dakota sandstone. This zone flowed gas to surface at low rates after a sand-diesel oil frac job which may have caused formation and skin damage.

In general, the magnitude of displacement on basement reverse faults is critical. At Kinney Field, the Nugget was thrust over Mowry source rock and filled with gas down to a gas/water contact. At Canyon Creek, fault displacement was probably less, so Nugget is wet and unproductive. Gas shows and gas production is from basal Dakota chert pebble conglomerates with good porosity and may be due to faulting of this section up and over Mowry source rocks.

The concept of drilling wells in or near fault zones seen on 3-D seismic to find the best fracture systems in tight gas sand reservoirs has not yet been tried here--although there are rumors that MVKD #3 'fell off the front edge' of the structure and ended up near the reverse fault by accident.

Log Analysis of Frontier and Dakota Sandstones. As the Kinney and Canyon Creek Fields are Laramide-age anticlinal structures, which contain tight gas sandstone reservoirs in the Lower Cretaceous Frontier and Dakota Formations at depths of 12,800 to 15,000 feet, reservoir temperatures range from 230 to 300 degF. High drilling mud weights (14-15 ppg) and high measured reservoir pressures (0.58 - 0.71 psi/ft) indicate overpressured conditions.

Early wells at each field (1949, 1957) were logged with electrical logs and micrologs. Several Frontier and Dakota cores were collected. The core descriptions indicate quartzitic sandstones with generally low porosity, shale laminations and localized natural fracturing. Lenses with unusually high porosity (12 - 19 %) were found occasionally in chert conglomerate fluvial channels of the Dakota Fm along the crests of the structural highs.

Additional wells were drilled in the 1970's to test the Dakota and Nugget reservoirs at Canyon Creek and Kinney Fields. These wells were logged with DIL, Sonic and/or Density logs. Wexpro Kinney #6 (1980) has a dual induction log and a density-neutron log, and was selected for log analysis.

Two recent wells (Exxon #34 (1990) and Marathon VCD#3 (1997) have modern log suites with dual induction and/or high resolution induction logs and neutron-litho-density logs. These logs are available on Dwights/PI microfiche. These two wells with modern logs were selected for log analysis.

The Simandoux equation was selected for calculating water saturations in shaly sandstones. The Simandoux equation was used according to procedures outlined in Asquith, Log Evaluation of Shaly Sandstones: A Practical Guide, AAPG CECNS #31.

Vclay calculations and corrections to porosity logs were made according to procedures using gamma ray logs outlined in Asquith and Gibson, 1982. The Vclay calculations for the Frontier and Dakota ranged from 10 to 14%. These may be somewhat low, due to the subjective selection of the GR_{fin} value in the Vclay process. There are no special core analyses available in the public data set to calibrate clay contents or M and N values in this area.

Strong neutron-density crossover effects were observed in several Frontier and Dakota zones, indicating gas effects on the neutron logs. Sonic porosities are also affected by overpressured gas and clay content, and were observed to be unrealistically optimistic compared to density porosity readings.

Density porosity measurements were preferred over neutron or sonic porosity readings. Corrected porosity values ranged from 8 to 17 % for the Frontier and Dakota sandstones. The highest porosity (17%) is in a basal Dakota chert pebble conglomerate zone which produced gas. Core data substantiates this high porosity 'sweet spot'.

Resistivity readings were made from the Deep Resistivity logging tool. R_w data for the Dakota and Frontier reservoirs at Kinney Field was found in a Wyoming Geological Association guidebook: Frontier R_w = 0.37 at 68F; Dakota R_w = 0.45 at 68F. These R_w values were converted to R_w at F_m temperature using a conversion chart (Merkel, AAPG CECNS #14, Figure 7). Regional R_w data for the Frontier and Dakota are available from the 1985 Rocky Mountain Formation Water Resistivities catalogue (Denver Well Logging Society), but there are no data listed near Kinney or Canyon Creek.

Accurate R_w values are extremely important in the Simandoux equation, but the available R_w data for Kinney field is limited, and there are no R_w data available for the Frontier and Dakota sandstones at Canyon Creek Field. R_w values are the least constrained inputs to the Simandoux equation. Errors in saturation calculations are probably due to incorrect R_w inputs.

Simandoux water saturations ranged from 8 to 59 %, with most values between 26 to 45 %. These values are generally reasonable for low porosity, tight gas sandstones in high temperature, thermally mature and overpressured conditions. Water saturations calculated by the Archie equation are also listed for comparison, however these are not "Archie rocks".

Based on examination of well logs from the Kinney and Canyon Creek fields, the reservoir characteristics for these two field areas are shown in Table 5-1.

Table 5-1
Reservoir Characteristics at Kinney and Canyon Creek Fields

Well	Yr	Fmn	Field	Depth (ft.)	Vclay	Dporcor	Rdeep	Rw at BHT	Rshale	Archie Sw	Simandoux Equation Sw	Comments
Exxon 34	90	Fr	CC	12843	0.11	0.106	140	0.1	15	0.26	0.26	
Exxon 34	90	Fr	CC	12888	0.11	0.12	85	0.1	15	0.31	0.29	
Exxon 34	90	Dak	CC	13320	0.1	0.14	220	0.12	3	0.17	0.39	
Exxon 34	90	Dak	CC	13249	0.1	0.08	150	0.12	3	0.35	0.15	
Exxon 34	90	Dak	CC	13236	0.1	0.083	300	0.12	3	0.24	0.08	Very high Rdeep, Sw is too low?
Mar. VCD #3	97	Fr	K	13506	0.13	0.078	40	0.1	7	0.64	0.45	
Mar. VCD #3	97	Fr	K	13510	0.13	0.065	70	0.1	7	0.58	0.59	WGA Report Rw = .37 at 68F
Mar. VKD #3	97	Dak.	K	13942	0.14	0.087	55	0.1	3	0.49	0.26	WGA Report Rw = .45 at 68F
Mar. VKD #3	97	Dak	K	14173	0.12	0.86	40	0.1	7	0.58	0.44	
WXPR K #6	80	Dak	K	14200	0.1	0.17	45	0.1	4	0.27	0.21	MFS memo, Avg Sw = 0.30

Section B: Initiation Analysis of the Deep Green River Partition with Respect to the Stratos Well and Assessment of the Resource in the Partition

Examination of the Green River Deep partition which contains the Stratos Federal No. 1 well was initiated, but will be completed in the first quarter of the next fiscal year. The Stratos well was part of a project to evaluate the natural gas potential of the Upper Cretaceous Frontier Formation in the central portion of the Green River Basin below a depth of 15,000 feet. Drilled to offset two deep Frontier wells (No. 31-1 Blue Rim Federal and No. 1-30 Blue Rim Federal), the Stratos well failed to meet expectations. Examination of the Green River Deep partition will address the Stratos well results.

Chapter 6

Technology Transfer

Advanced Resources presented the results of the Rulison field test at two separate conferences. The first conference where Advanced Resources presented at was the Innovative Applications of Petroleum Technology in the Rocky Mountain Area sponsored by the Rocky Mountain Association of Geologists. The conference was held on October 30, 1997 in Denver. The second conference was the Greater Green River Symposium sponsored by the Department of Energy, the Gas Research Institute, and IPAMS held at Denver, Colorado on November 11, 1997. Copies of the presentations for these conferences follow as Sections A and B in this chapter, respectively.

Section C: Refining the Exploration Process for Deep, Naturally-Fractured Gas Reservoirs. We presented the results of this work on the exploration and prospect delineation process for naturally-fractured reservoirs at the GRI-sponsored Deep Gas Forum (Series #2) in Denver on October 15 and 16.

Section D of this chapter is a presentation that was made at the International Gas Resource Conference in San Diego, California in November, 1998 on advanced reservoir characterization to develop tight lenticular sands of the Piceance Basin.

Chapter 6
Section A
Rocky Mountain Association of Geologists Presentation

Using 3D Seismic to Characterize Natural Fractures in the Rulison Field, Piceance Basin

David J. Campagna, Ph.D.

Vello Kuuskraa

Advanced Resources International, Inc.

"Applications of Petroleum Technology in the Rocky Mountain Region"

RMAG Continuing Education Seminar

October 30, 1997 Denver, Colorado

Outline for Presentation

1. *Introduction*
2. *Project Setting*
3. *3D Seismic Survey*
4. *Seismic Attributes*
5. *Fault Mapping*
6. *EUR Correlation*
7. *Structural Analysis*
8. *Conclusions*

1. Introduction: Rulison Field Project

Project Title:

**Naturally Fractured Tight Gas Reservoir
Detection Optimization**

Project Objective:

***Optimize geological and geophysical
techniques for economically detecting, mapping
and evaluating naturally fractured tight gas
reservoirs.***

1. Introduction: Project Participants

Sponsors:

***DOE Federal Energy Technology Center
Barrett Resources***

Co-investigators:

***Western Geophysical
Lynn & Associates
Basin Energy***

1. Introduction: Project Rationale

- ◆ Areas of natural fracture enhanced permeability exist in extensive low-permeability, gas-saturated basins
- ◆ Random drilling and shear wave seismic are high cost approaches for locating naturally fractured areas
- ◆ Lower cost methods utilizing satellite imagery, aeromagnetic data and modified P-wave seismic (applied in an integrated fashion) offer a new, powerful technology

1. Introduction: Today's Topic

Integrated fault mapping, azimuthal P-wave analysis, and structural analysis offers a new, powerful method for locating natural fractures in advance of drilling.

2. Project Setting

- ♦ The Piceance basin in Colorado contains a vast accumulation of gas in tight, massively stacked, lenticular sands.
 - 321 Tcf (USGS, 1987)
 - 311 Tcf (ARI, 1996)
- ♦ Considerable past and ongoing R&D sponsored by DOE/FETC and GRI has been directed at this basin (MWX and M Site)

2. Project Setting: Basin Character

2. Project Setting: Rulison Field

- ◆ The area around the Rulison Field, southeast Piceance basin, holds the region's richest concentrations of gas in place:

- 160 Bcf per section in Williams Fork Member, Mesaverde Fm.
- 40 Bcf per section in the deeper Cameo and Goal Ridge coals

2. Project Setting: Rulison Field

- ◆ The Rulison / Williams Fork field in Garfield County, Colorado (T6 & 7S, 94W) was discovered in 1956 with the drilling of the Juhan #1 well. The field is estimated to have approximately 10 Tcf of gas in place in the Mesaverde tight sands, plus additional gas resources in the underlying and interfingering Cameo coals.
- ◆ In the next 36 years, through 1992, only 36 more wells were drilled, with generally poor to marginal reserves and numerous dry holes. Under these conditions (confirmed by the USGS assessment), the Rulison field was judged to be an uneconomic gas play:

- Average EURs/successful well – 0.9 Bcf

- Dry hole rates – 45%

2. Project Setting: Productivity History

2. Project Setting: Rulison Field

- ◆ Characterization of the massively stacked, lenticular tight sands (the DOE/GRI MWX site is located on the southern edge of the field), introduction of improved well completion practices by Barrett Resources and inference of areas with higher permeability and sand development revitalized this gas play.
- ◆ From 1993 through early 1997, 65 new wells have been drilled with significantly improved EURs and gas production rates; also, many of the older wells have been recompleted. At the end of 1996:
 - The field had produced 40 Bcf
 - Gas production in 1996 averaged 325 MMcfd

2. Project Setting: Stratigraphy

The Williams Fork Member is a massively stacked, lenticular nonmarine unit of the Mesaverde Fm. containing sandstones, shales, and coals.

ERA	SYSTEM	SERIES	STAGE	UNIT
CENOZOIC	TERTIARY	Eocene		Uinta Fm.
				Green River Fm.
				Wasatch Fm.
		Paleocene		
MESOZOIC	CRETACEOUS	Upper	Maestrichtian	
		Campanian		
			Mesaverde Group	
			Williams Fork Fm.	
			Ilia Fm.	
				Cameo coal zone
				Rollins Sh.
				Corralito Sh.
				Chinle Sh.
				Castlegate Sh.

Modified from Ayler and Schumacher, 1985 and Lorenz, 1988

2. Project Setting: Reservoir & Matrix Permeability

Natural fractures enhance permeability by an order of magnitude

2. Project Setting: Fracture Evolution

2. Project Setting: Rulison Field

- ◆ The field operator, Barrett Resources, has plans to intensively develop the higher productivity portions of the field at 20 to 40 acres per well. This would provide, theoretically, one to two thousand locations.
- ◆ A significant high-productivity trend, plus smaller pockets of natural fractures, exists at Rulison and has been mapped. Assuming 20% of the area has higher productivity, 200 to 400 high quality new wells could be drilled.

2. Project Setting: Objectives

- ◆ The objective of our field study is to further delineate sweet spots at Rulison (and in the adjacent southern Piceance Basin). When done in advance of drilling, this will provide significant value in terms of higher recovery per well, lower dry hole rates and lower-cost gas reserves.

3. Project Setting: Integrated Technologies

1. *Basin Deposition and Tectonic History:*
Geologic Framework
2. *Satellite Imagery:*
Structural Framework
3. *High Resolution Aeromagnetic Data:*
Trend Definition
4. *Azimuthal 3D P-Wave Survey:*
Well Site Selection

2. Project Integration: Scale & Cost

3. 3D Seismic: Objectives

- ◆ Establish P-wave seismic attributes that reliably correspond to orientation and intensity of open natural fractures.
- ◆ Map subtle fault systems.

3. 3D Seismic: Acquisition

◆ Design

- Full-azimuth, high-fold, full-offset
- Receiver spacing of 220 feet (bin size of 110' by 110')

◆ Processing

- Entire volume was separated into two limited azimuth volumes, N150E and N60E (+/- 45°)

3. 3D Seismic: Location

The 3D seismic survey covers 4.5 sq. miles and was located over highly productive areas as well as less productive areas in the Rulison field

3. 3D Seismic Survey

Well control provided by Barrett 68-21 within the survey area established seismic correlation with the major horizons.

4. Seismic Attributes: Theory

Theory predicts that P-waves travel slower when propagating across open fractures; this effect is enhanced when fractures are gas-filled.

A 1500-2000' interval between the z and cameo coals is examined using seismic attributes of interval velocity, AVO gradient, and difference by azimuth of interval velocity.

4. Seismic Attributes

DIX INTERVAL VELOCITY - RATIO (N60E / N30W)
Z TO CAMEO COALS

Interval velocity analysis shows a distinct NW-trending zone of anisotropy indicating N30W fractures.

4. Seismic Attributes

SUM OF AVO GRADIENT - Z TO CAMEO COALS

Strong positive gradients occur in the SW and NE portions of the survey. Positive gradients indicate fractures.

5. Fault Mapping

3D seismic data reveal small reverse faults in Rulison Field:

- ◆ Previous mapping using 2D seismic revealed no faulting (Barrett Resources).
- ◆ Mapping 3D seismic identified subtle reverse faults.
- ◆ Reverse faults, e.g. the NW2 fault, intersect the pay interval at a relatively low angle at the top of Cameo coal and terminate below the gas-water transition zone in the Mesaverde.

5. Fault Mapping: NE-SW profile

5. Fault Mapping: Cameo Horizon

The NW2 reverse fault trends N40W, enters the seismic survey from the southeast and dies out laterally to the NW.

5. Fault Mapping: SS2 horizon

At the SS2 horizon, the NW2 reverse fault translates to the southwest and terminates at the horizon.

6. EUR Correlation

- ◆ Within the 3D seismic survey, 27 wells have been drilled.
- ◆ The EURs of these wells are compared with results of fault mapping and P-wave analysis.

6. EUR Correlation: Fault mapping

NW2 fault parallels
EUR trend with best
wells west of fault.

Projection of
NW2 fault plane
from Cameo to
SS2 horizons.

6. EUR Correlation: Fault Mapping

Correlation of NW2 Fault with Well Performance

	West of NW2 Fault Zone	East of NW2 Fault Zone
Number of Wells	17	10
Average EUR/Well	2.32 Bcf	1.37 Bcf
Range of EUR/Well*	1.57 to 3.26 Bcf	0.98 to 1.84 Bcf

*After eliminating best and worst wells.

6. EUR Correlation: Seismic Attributes

Multiple seismic attributes identify wells with EURs greater than 2.0 Bcf.

- + 0.5 PT / 100 POS GRAD SUM AVO
- +1 PT / 100 GRAD DIF AVO > 100
- VEL. ANIS.: +0.5 PT PER % >4%
- +1 PT IF MAX. INT. VEL. >13500'/S
- +1 IF CONSIST ORIENT AZIM & HI MAGN

7. Structural Analysis

We observe that the permeable fracture network is a local phenomenon related to small reverse faults, and that wells with high EUR values occur near a fault tip.

Structural analysis will combine field observations, data analysis, and experimental theory to provide a robust exploration strategy.

7. Structural Analysis: Fracture Theory

Stress around fault tip

Secondary structures

7. Structural Analysis: Experiments

Small incision cut into a photoelastic material and placed under biaxial stress. Stress concentration around tip and asymmetry due to orientation of cut to stress direction.

7. Structural Analysis: Experiments

Experiments deforming rocks under confining pressures result in the formation of numerous fractures during contractional strain. The fractures concentrate near fault tips and in the footwall of the reverse fault system.

from Logan and others, 1979

7. Structural Analysis: 3D Seismic

The Clough RMV 7-21 has an EUR > 3Bcf whereas the Clough 3 has an EUR ~1Bcf

The difference may be due to location with respect to fault tip where the greatest amount of fracturing occurs.

7. Structural Analysis: Fracture Orientation

Consistent with theory, the orientation of fractures rotate 180° across reverse faults at the Cameo horizon.

↔ Fracture Orientation

7. Structural Analysis: 3D Seismic

Present-day stress, directed N80W, may cause offset of open fracture location to northwest lateral terminus of fault.

Other factors include sand thickness and location.

8. Conclusions

- ◆ Advanced Resources' natural fracture detection project at Rulison shows that it is possible to map subtle reverse faults responsible for permeability-based sweet spots in the tight, massively stacked sands.
- ◆ The information from structural analysis of the 3D seismic shoot has helped delineate the higher productivity trends
 - EUR's within the trend are 2+ Bcf
 - EUR's outside the trend are ~1 Bcf

8. Conclusions

- ◆ Natural fracture detection technology that combines 3D seismic fault mapping and 3D stress modeling may ultimately unlock the vast resources held in tight, lenticular-sand gas plays, as shown for the Rulison field:

	<u>EUR's</u>	<u>Dry Holes</u>
Historical Performance (1956-1972)	0.9 Bcf/well	45%
Recent Technology-Based Performance	2.0 Bcf/well	low

Chapter 6
Section B
GRI-DOE-IPAMS Presentation

Fault Mapping and Natural Fracture Detection Using 3D Seismic Data

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Advanced Resources International, Inc.

"Advances in Seismic Technologies"
A Consortium for Emerging Gas Resources
in the Green River Basin

IPAMS

November 11, 1997 Denver, Colorado

Outline for Presentation

- 1. Introduction**
- 2. Project Setting**
- 3. 3D Seismic Survey**
- 4. Seismic Attributes**
- 5. Fault Mapping**
- 6. EUR Correlation**
- 7. Structural Analysis**
- 8. Conclusions and Future Directions**

1. Introduction: Rulison Field Project

Project Title:

**Naturally Fractured Tight Gas
Reservoir Detection Optimization**

Project Objective:

***Optimize geological and geophysical
techniques for economically detecting, mapping
and evaluating naturally fractured tight gas
reservoirs.***

1. Introduction: Project Participants

Sponsors:

***DOE Federal Energy Technology Center
Barrett Resources***

Co-investigators:

***Western Geophysical
Lynn & Associates
Basin Energy***

1. Introduction: Today's Topic

Integrated fault mapping, azimuthal P-wave analysis, and structural analysis offers a new, powerful method for locating natural fractures in advance of drilling.

2. Project Setting

- ◆ **The Piceance basin in Colorado contains a vast accumulation of gas in tight, massively stacked, lenticular sands.**
 - **321 Tcf (USGS, 1987)**
 - **311 Tcf (ARI, 1996)**
- ◆ **Considerable past and ongoing R&D sponsored by DOE/FETC and GRI has been directed at this basin (MWX and M Site)**

2. Project setting: Basin Character

2. Project Setting: Rulison Field

- ◆ The Rulison / Williams Fork field in Garfield County, Colorado (T6 & 7S, 94W) was discovered in 1956 with the drilling of the Juhan #1 well. The field is estimated to have approximately 10 Tcf of gas in place in the Mesaverde tight sands, plus additional gas resources in the underlying and interfingering Cameo coals.
- ◆ In the next 36 years, through 1992, only 36 more wells were drilled, with generally poor to marginal reserves and numerous dry holes. Under these conditions (confirmed by the USGS assessment), the Rulison field was judged to be an uneconomic gas play:
 - Average EURs/successful well – 0.9 Bcf

2. Project setting: Rulison Field

- ◆ The area around the Rulison Field, southeast Piceance basin, holds the region's richest concentrations of gas in place:

- 160 Bcf per section in Williams Fork Member, Mesaverde Fm.
- 40 Bcf per section in the deeper Cameo and Coal Ridge coals.

2. Project Setting: Stratigraphy

The Williams Fork Member is a massively stacked, lenticular nonmarine unit of the Mesaverde Fm. containing sandstones, shales, and coals.

ERA	SYSTEM	SERIES	STAGE	UNIT
CENOZOIC	TERTIARY	Eocene		Uinta Fm
				Green River Fm
				Wasatch Fm.
		Paleocene		
MESOZOIC	CRETACEOUS	Upper	Maestrichtian	
		Campanian

2. Project Setting: Reservoir & Matrix Permeability

2. Project Setting: Rulison Field

- ◆ Characterization of the massively stacked, lenticular tight sands (the DOE/GRI MWX site is located on the southern edge of the field), introduction of improved well completion practices by Barrett Resources and inference of areas with higher permeability and sand development revitalized this gas play.
- ◆ From 1993 through early 1997, 65 new wells have been drilled with significantly improved EURs and gas production rates; also, many of the older wells have been recompleted. At the end of 1996:
 - The field had produced 40 Bcf
 - Gas production in 1996 averaged 325 MMcfd

2. Project Setting: Rulison Field

- ◆ The field operator, Barrett Resources, has plans to intensively develop the higher productivity portions of the field at 20 to 40 acres per well. This would provide, theoretically, one to two thousand locations.
- ◆ A significant high-productivity trend, plus smaller pockets of natural fractures, exists at Rulison and has been mapped. Assuming 20% of the area has higher productivity, 200 to 400 high quality new wells could be drilled.

2. Project Setting: Objectives

- ◆ The objective of our field study is to further delineate sweet spots at Rulison (and in the adjacent southern Piceance Basin). When done in advance of drilling, this will provide significant value in terms of higher recovery per well, lower dry hole rates and lower-cost gas reserves.

3. 3D Seismic: Objectives

- ◆ Establish P-wave seismic attributes that reliably correspond to orientation and intensity of open natural fractures.
- ◆ Determine ability to map subtle fault systems.

3. 3D Seismic: Acquisition

- ◆ Design
 - Full-azimuth, high-fold, full-offset
 - Receiver spacing of 220 feet (bin size of 110' by 110')
- ◆ Processing
 - Entire volume was separated into two limited azimuth volumes, N150E and N60E (+/- 45°)

3. 3D Seismic: Location

The 3D seismic survey covers 4.5 sq. miles and was located over highly productive areas as well as less productive areas in the Rulison field

3. 3D Seismic Survey

Well control provided by Barrett 68-21 within the survey area established seismic correlation with the major horizons.

4. Seismic Attributes: Theory

Theory predicts that P-waves travel slower when propagating across open fractures; this effect is enhanced when fractures are gas-filled.

A 1500-2000' interval between the z and cameo coals is examined using seismic attributes of interval velocity, AVO gradient, and difference by azimuth of interval velocity.

4. Seismic Attributes

DIX INTERVAL VELOCITY - RATIO (N60E / N30W)
Z TO CAMEO COALS

Interval velocity analysis shows a distinct NW-trending zone of anisotropy indicating N30W fractures.

4. Seismic Attributes

SUM OF AVO GRADIENT - Z TO CAMEO COALS

Strong positive gradients occur in the SW and NE portions of the survey. Positive gradients indicate fractures.

5. Fault Mapping

3D seismic data reveal small reverse faults in Rulison Field:

- ◆ Previous mapping using 2D seismic revealed no faulting (Barrett Resources).
- ◆ Mapping 3D seismic identified subtle reverse faults.
- ◆ Reverse faults, e.g. the NW2 fault, intersect the pay interval at a relatively low angle at the top of Cameo coal and terminate below the gas-water transition zone in the Mesaverde.

5. Fault Mapping: NE-SW profile

5. Fault Mapping: Cameo Horizon

The NW2 reverse fault trends N40W, enters the seismic survey from the southeast and dies out laterally to the NW.

5. Fault Mapping: SS2 horizon

At the SS2 horizon, the NW2 reverse fault translates to the southwest and terminates at the horizon.

6. EUR Correlation

- ◆ Within the 3D seismic survey, 27 wells have been drilled.
- ◆ The EURs of these wells are compared with results of fault mapping and P-wave analysis.

6. EUR Correlation: Fault mapping

6. EUR Correlation: Fault Mapping

Correlation of NW2 Fault with Well Performance

	West of NW2 Fault Zone	East of NW2 Fault Zone
Number of Wells	17	10
Average EUR/Well	2.32 Bcf	1.37 Bcf
Range of EUR/Well*	1.57 to 3.26 Bcf	0.98 to 1.84 Bcf

*After eliminating best and worst wells.

6. EUR Correlation: Seismic Attributes

Multiple seismic attributes may be able identify wells with EURs greater than 2.0 Bcf - though results depend on arbitrary weights specific to the test well data set

7. Structural Analysis

We observe that the permeable fracture network is a local phenomenon related to small reverse faults, and that wells with high EUR values occur near a fault tip.

Structural analysis will combine field observations, data analysis, and experimental theory to provide a robust exploration strategy.

7. Structural Analysis: Fracture Theory

Stress around fault tip

Secondary structures

7. Structural Analysis: Experiments

Small incision cut into a photoelastic material and placed under biaxial stress. Stress concentration around tip and asymmetry due to orientation of cut to stress direction.

7. Structural Analysis: Experiments

Experiments deforming rocks under confining pressures result in the formation of numerous fractures during contractional strain. The fractures concentrate near fault tips and in the footwall of the reverse fault system.

from Logan and others, 1979

7. Structural Analysis: 3D Seismic

The Clough RMV 7-21 has an EUR > 3Bcf whereas the Clough 3 has an EUR ~1Bcf

The difference may be due to location with respect to fault tip where the greatest amount of fracturing occurs.

Clough RMV 7-21

Clough 3

7. Structural Analysis: Fracture orientation

Consistent with theory, the orientation of fractures rotate 180° across reverse faults at the Cameo horizon.

↔ Fracture Orientation

DIX INTERVAL VELOCITY - RATIO (N60E / N30W)
Z TO CAMEO COALS

7. Structural Analysis: 3D Seismic

Present-day stress is oriented N80W, oblique to NW2 fault, and causes an area of open natural fracture potential in the extensional quadrant of the fault.

○ Location of Extensional Quadrant

6. EUR Correlation: Fault Mapping

Correlation of NW2 Fault with Well Performance

	<u>West of NW2 Fault Zone</u>	<u>East of NW2 Fault Zone</u>
Number of Wells	30	18
Average EUR/Well	2.17 Bcf	1.27 Bcf
Range of EUR/Well*	1.28 to 3.58 Bcf	0.62 to 2.30 Bcf

*After eliminating best and worst wells.

7. Structural Analysis: 3D Seismic

Based on our results from the 3-D survey plus a 2-D interpretation, we expect that the highly productive area around Sec. 1 of T7S, R94W is also influenced by reverse faulting.

8. Conclusions and Future Directions

- ◆ Advanced Resources' natural fracture detection project at Rulison shows that it is possible to map subtle reverse faults responsible for permeability-based sweet spots in the tight, massively stacked sands.
- ◆ The information from structural analysis of the 3D seismic shoot has helped delineate the higher productivity trends
 - EUR's within the trend are 2+ Bcf
 - EUR's outside the trend are ~1 Bcf

8. Conclusions and Future Directions

- ◆ Natural fracture detection technology that combines 3D seismic fault mapping and 3D stress modeling may ultimately unlock the vast resources held in tight, lenticular-sand gas plays, as shown for the Rulison field:

	<u>EUR's</u>	<u>Dry Holes</u>
Historical Performance (1956-1972)	0.9 Bcf/well	45%
Recent Technology-Based Performance	2.0 Bcf/well	low

8. Conclusions and Future Directions

- ◆ The field experiment at Rulison shows that the link between natural fracture-related permeability and faulting mapped by 3D seismic provides a means to predict the occurrence of “sweet-spots” in low permeability reservoirs.
- ◆ By combining 3D seismic-based fault mapping with a numerical stress model, it may be possible to predict the location and key attributes of natural fractures:
 - Location and density
 - Orientation

8. Conclusions and Future Directions

- ◆ Further field tests of the capability of a combined 3D seismic fault mapping and a 3D stress model for natural fracture evaluation are required to calibrate and demonstrate this technology.
- ◆ Additionally, the information derived from the stress model may help define the critical azimuths for using seismic attributes (e.g., P-wave velocity analysis) in detecting open natural fractures.

Chapter 6
Section C
Presentation made to the Deep Gas Forum

The Exploration Process for Deep, Naturally-Fractured Gas Reservoirs

*Integrating Multiple Data and Analyses
for Successful Exploration Programs*

David J. Campagna, Ph.D.
Advanced Resources International, Inc.

GRI's Deep Gas Forum Series #2

15-16 October 1998 Denver, Colorado

Outline

This presentation will cover the following topics:

- **Exploration Program & Tools for Deep Gas**
- **Exploration Case Study**
 - **Regional Work and Play Definition**
 - **Prospect Delineation**
- **Conclusions & Discussion**

Gas Production and Net Pay

Net pay and hydraulic fracs in the Frontier shows little correlation with EUR. This is not to imply that net pay and hydraulic fracs are unimportant; rather, this shows that thick pay and fracs are not sufficient to make an otherwise geologically-poor area productive.

Gas Production and Natural Fractures

Permeability is the most important production controlling mechanism in the Frontier Fm, with the presence (or absence) of natural fractures controlling permeability in this formation.

High-Resolution Aeromagnetic and Imagery Data

- High-resolution aeromagnetic and imagery data covering 19 townships were examined along northern margin of the Washakie basin along the Wamsutter arch.
- The goals in the analysis of these data were to provide relevant information on:
 - regional basement-related structural trends
 - local patterns of surface fractures
 - structural partitions and any control over fracture trends.

Natural Fractures Observed In Cores

Shear(ed) fractures are identified in core by:

Natural Fracture Characterization

- The natural fractures present are fault-related showing dominantly oblique-reverse shear with an extensional component.
- Open isolated voids in core result from step-overs in the shear fractures.
- The voids are connected by single fractures that are typically filled with mineral deposits.
- Open voids represent storage for gas whereas the connecting shear fractures provide the deliverability (i.e., the controlling factor in permeability).

3-D Seismic: Fault Mapping

Three profile views of the fault system from south to north show the characteristics of the thrust fault, intersection with strike-slip fault, and where the faults diverge in the north.

Subsea structure of the Madison Fm

GRI

3-D Seismic: Fault Mapping

Profile view of Table Rock thrust fault near Govt. Union #4.

Thrust fault is steeply dipping and an asymmetrical fold is well developed on the hanging wall.

Frontier

Madison

GRI

3-D Stress Model: Results

Predicted location of shear fractures covers 8 miles².

Greatest intensity of natural fractures should occur between Govt. Union #4 and Table Rock #104.

Predicted shear orientations are N27W and N87W.

GRI

3-D Stress Model: Results

Predicted location of shear fractures is consistent with the production rates.

Govt. Union #4 produces 6,000 mcf, Table Rock #104 IP'd at 4,300 mcf and currently produces at 300 mcf. Initial tests of Table Rock Units #22 and #43 were discouraging and the wells are shut-in.

GRI

Chapter 6

Section D

Using Advanced Reservoir Characterization to Develop the Tight, Lenticular Sands of the Piceance Basin

USING ADVANCED RESERVOIR CHARACTERIZATION TO DEVELOP THE TIGHT, LENTICULAR SANDS OF THE PICEANCE BASIN

**L'UTILISATION DE CARACTERISATION
AVANCEE DU RESERVOIR AU DEVELOPPEMENT
DES GRES LENTICULAIRES A BASSE PERMEABILITE
DANS LE BASSIN PICEANCE**

**V.A. Kuuskraa and D.J. Campagna
Advanced Resources International, Inc., USA
IGRC, San Diego, California
*November 8-11, 1998***

Outline

- 1. Tight Gas Sands - Piceance Basin**
- 2. Advanced Reservoir Characterization**
 - *Log Interpretation***
 - *Natural Fracture Detection***
- 3. Benefits of Technology**

Introduction

Tight sands and basin-centered gas are a major undeveloped U.S. natural gas resource:

- **Technically recoverable resource estimates of 349 Tcf (NPC '92) to 411 Tcf (EIA '97) in a dozen large basins.**
- **Only the high quality portions, the “sweet spots”, of this resource will be economically recoverable.**
- **Technology for finding and defining these “sweet spots” is one of industry’s highest priorities.**

Piceance Basin

Williams Fork Fm. gas-saturated region

- Mesaverde outcrop
- Williams Fork gas field
- Water-saturated zone
- Gas-saturated zone

COLORADO

S. Piceance Basin: Gas In-Place

Contours: Bcf/mi²

The S. Piceance Basin holds a rich, basin-centered gas accumulative with over 100 Tcf of gas in-place in the Mesaverde lenticular sands.

Piceance Basin

The reservoir properties of the lenticular Williams Fork sands at Rulison are:

• Depth	--	6,500 to 7,500 ft
• Net pay	--	300 to 500 ft
• Porosity	--	8 to 10%
• Water Saturation (below transition zone)	--	40%
• Permeability	--	5 μ d (1 to 10 μ d)
• Permeability Anisotropy	--	2:1 to 10:1
• Pressure	--	Overpressured
• Sand body	--	750' x 4,500' (with perm. barriers)

Distribution of Well Performance - Rulison Field (WF)

Key Technologies

Integrated use of reservoir characterization and natural fracture detection technologies are essential for finding “sweet spots” in tight gas sands:

- *Advanced well log analysis*
- *Natural fracture detection*

1. Advanced Well Log Analysis

Problems Being Addressed

Conventional log analysis in tight, lenticular sands is not reliable. Operators are reverting to mud logs and shows.

Archie model for log analysis leads to erroneously high water saturations in these clay rich sands.

Conventional Log Analysis

Problem #1 ← Uncertain location of transition zone due to variable Rw.

Problem #2 ← Unreliably high Sw due to active clays.

Problem #3 ← Bypassed zone with high gas productivity.

Waxman-Smiths versus Archie

Water Saturation (%)

Benefits of Well Recompletion

The well recompletion program at Rulison Field has been highly cost-effective:

- Number of Wells(zones) -- 12 (31)**
- Cost per Well (@2.6 zones/well) -- \$300,000**
- Increased Reserves per Well -- 1.73 Bcf**
- Cost per Mcf of Reserves -- \$0.17**

Results of Well Recompletion at Rulison Field

Well Name	Original Completion Date	Zones Added	Increase in EUR MMcm/Bcf
1993-1994 Program			
RMV 2-27	11/89	4	79 (2.8)
RMV 1-28	9/89	4	76 (2.7)
GV 25-27	7/91	3	71 (2.5)
Clough #14-22MV	11/90	2	65 (2.3)
GV 9-33	4/91	3	34 (1.2)
Clough #26	5/82	3	34 (1.2)
Clough #3*	6/80	2	8 (0.3)
1995 Program			
Clough #21	1/84	2	45 (1.6)
Clough #19	3/81	2	85 (3.0)
Clough #20	9/80	1	11 (0.4)
Mead 24-14	10/89	2	17 (0.6)
Federal 9-17	10/91	3	62 (2.2)

2. Identification of Natural Fracture Trends

Southern Piceance Basin (Williams Fork Formation)

Problems Being Addressed.

- Major structures have been drilled, leaving more subtle features as targets.
- Past exploration and wellsite selection “rules” led to many uneconomic completions.
- Mapping of net pay is not adequate for optimizing well locations in stacked, fluvial sands.

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Matrix and Reservoir Permeabilities at Rulison Field

Lorenz, 1988

Core Analysis of the Williams Fork Sands Show Matrix Permeabilities of One Microdarcy. Over the Same Interval, Well-Test Based Reservoir Permeabilities Are 10+ Times Higher Due To Natural Fractures.

Relationship of Gas Recovery and Permeability Rulison Field, Piceance Basin

Regional Basin High-Grading

Statistical Approach

- Multiple Well Drilling Program

Prospect Development

- Advanced Seismic
- Quantitative Models

Basin Appraisal and Resource Characterization

Regional Analysis

Satellite Imagery

High Resolution Aeromagnetics

Regional Productivity Trends

Prospect Delineation

3-D Seismic

Quantitative Stress Model

Areas of Enhanced Permeability

Exploration Technologies for Deep, Naturally Fractured Reservoirs

Seismic Profile

Clough RMV 7-21 has an EUR > 3Bcf whereas the Clough 3 has an EUR around 1 Bcf. The difference is due to presence of fault-related natural fracture clusters.

Predicting Fault-Related Sweet-Spots

Basic geomechanics theory can be used to quantitatively establish the relationship between faults and natural fractures.

- Inputs. Fault geometry (from 3-D and 2-D seismic data), fault displacement, and material properties.
- Approach. Boundary Element Method stress model
- Output. Location, intensity, and orientation of principal tensile stress (natural fractures).

Stress Profile

VERTICAL SLICE
(CROSS SECTION VIEW)

N ↓

Results at Rulison South Test Area

	<u>Wells Inside Envelope</u>	<u>Wells Outside Envelope</u>
No. Wells	7	17
Avg. EUR/Well	3.2 Bcf	1.2 Bcf
Avg. Perm. (μd)	25	6
Avg. Net Pay	306 ft	304 ft

Conclusions

The Piceance Basin project used reservoir characterization and natural fracture detection technologies to find "sweet spots" and recompletion targets in tight gas sands.

- *Structural and basement analysis, using satellite imagery and aeromagnetics, helped define the regional trends.*
- *Improved log analysis helped target high quality pay.*
- *3-D seismic data and quantitative models enabled the project to image subtle faults, for areas of natural-fracture related permeability.*

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