Naturally Fractured Tight Gas Reservoir Detection Optimization

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CHAPTER 1
Project Summary

The "Naturally Fractured Tight Gas Reservoir Detection Optimization" Project has been conducted by Advanced Resources International, Inc. for the U.S. Department of Energy, Federal Energy Technology Center (Contract No. DE-AC21-93MC30086). The purpose of the contract is to identify, field test and optimize existing natural fracture detection technology for low permeability ("tight") natural gas reservoirs.

The central premise of the Project is that an integrated approach involving fundamental geology, remote sensing, advanced seismic and quantitative structural and stress analysis ("geomechanics") will provide the optimum approach for cost-effectively defining the intensively naturally fractured areas ("sweet spots") of tight gas reservoirs, **Figure 1-1**.

PHASE ONE: GEOLOGIC CHARACTERIZATION. The First Phase of the Project involved geologic characterization of the Southern Piceance Basin, the proposed area for the field demonstration of natural fracture detection technology. A detailed geologic and field case study was performed at Rulison Field to better understand the relationship between gas production, reservoir stratigraphy, and the regional and local structural setting, **Figure 1-2**. Detailed mapping of the Williams Fork and Rollins sandstones documented that previously undefined, small-scale structural features existed at Rulison Field and correlated, in general, with favorable trends in gas production.

The First Phase also initiated the application and testing of a numerical basin model to determine whether the current natural fracture conditions in a tight gas basin can be rigorously established from the fundamental sediment, stress and rock rheology history of a basin.

PHASE TWO: INTEGRATED REGIONAL ASSESSMENT. The Second Phase of the Project involved the integrated application of remote sensing methods (SLAR, side-looking airborne radar and TM, thematic mapper), high-resolution aeromagnetic data, and 2D seismic. The purpose

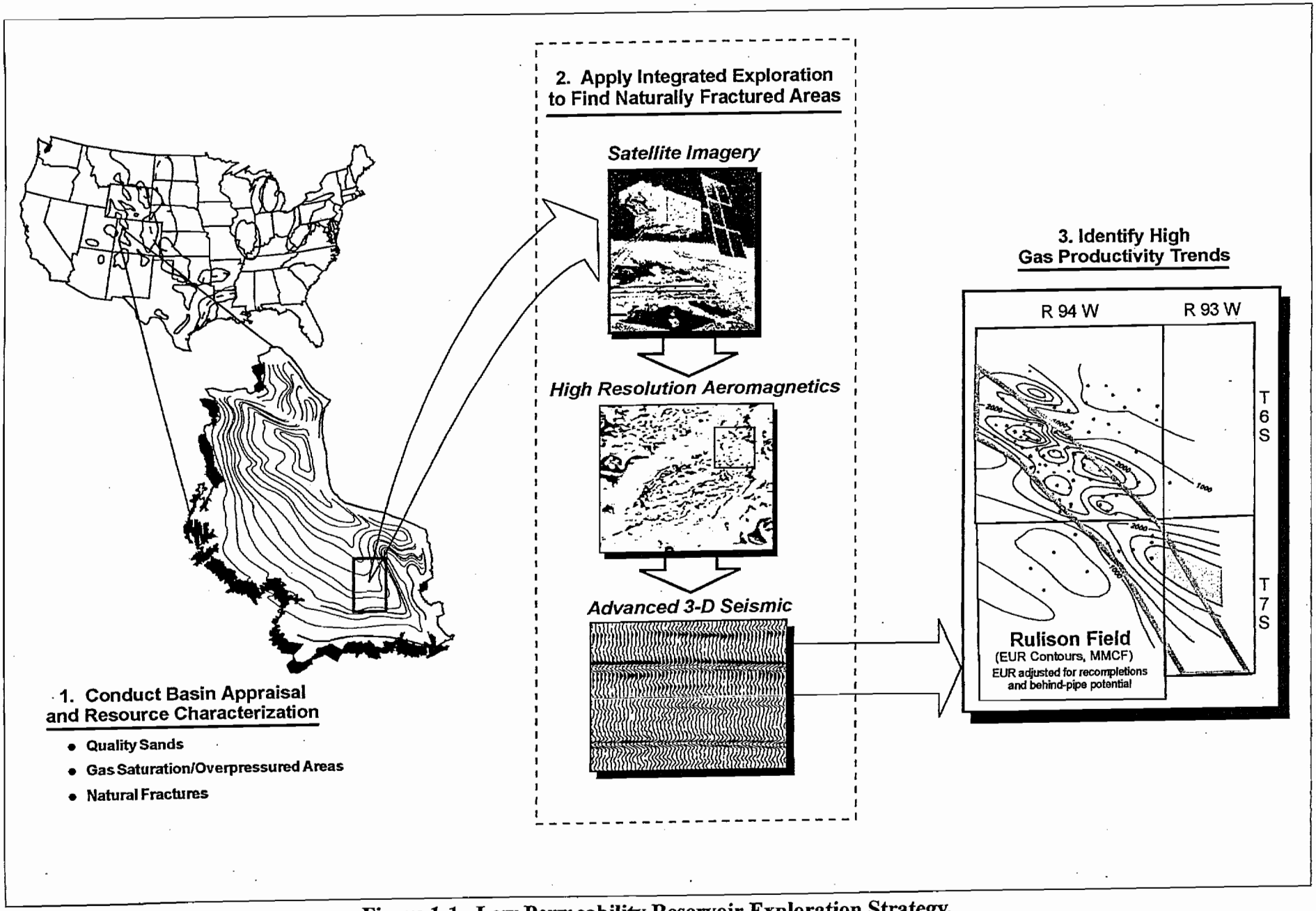


Figure 1-1. Low Permeability Reservoir Exploration Strategy.

The Piceance Basin is a basin-center deposit with 300 Tcf of gas in-place. The Rulison Field, located in the southeastern portion of the basin, produces from over-pressured tight sands of the Williams Fork Fm., Upper Cretaceous Mesaverde Group:

- *Drilling depths -- 6,500-7,500'*
- *Net pay-- 300-500'*
- *Porosity -- 8-12%*
- *Water saturation -- 35%*
- *Permeability -- 5 μd (1-50 μd)*

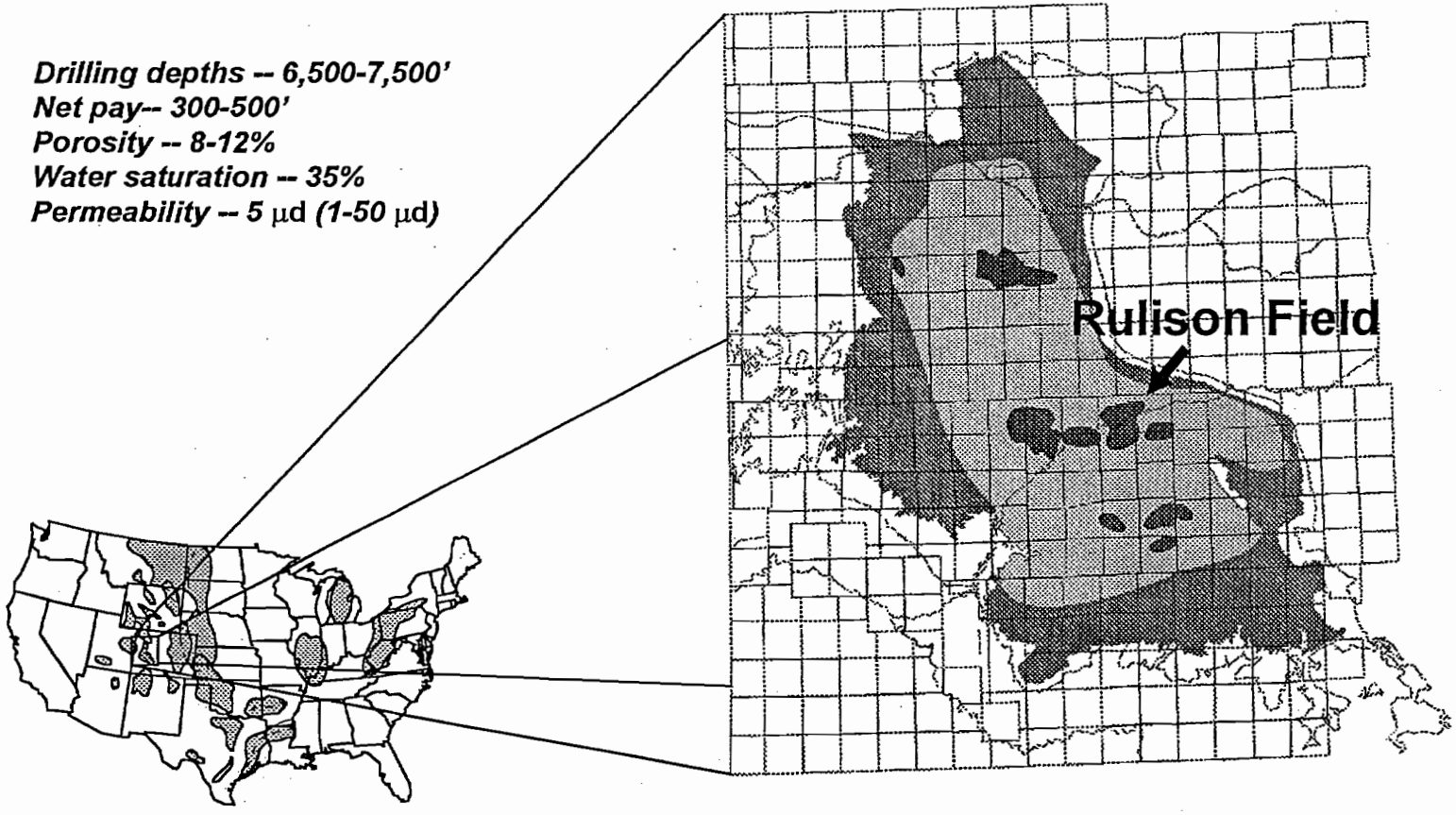


Figure 1-2. Rulison Field, Piceance Basin, Colorado

was to assess the regional and basement structures, the influence of these structures on subsurface faults and natural fractures, and the surface manifestation of these regional faults and basement structures in the Southern Piceance Basin. This work helped identify a NW-SE trend of complex tectonic features that appeared to correlate with higher productivity natural gas wells in the Rulison Field. A high-resolution aeromagnetic survey for the Southern Piceance Basin was flown for the Project by World Geoscience. The survey involved close line spacing (400 meters by 1,600 meters) and low aircraft flight elevation (150 meters above mean terrain). The imaging and aeromagnetic survey data were combined with 400 line mile of 2D seismic data and extensive subsurface well control (provided by Barrett Resources, Advanced Resources' industry partner for the project) to select the location for the planned seismic survey and natural fracture detection test in the Rulison Field.

PHASE THREE: MULTI-AZIMUTH 3D SEISMIC SURVEY. Phase Three of the Project involved a 3D, P-wave full-azimuth seismic survey. The first goal was to acquire a survey with sufficient fold to evaluate the application of azimuthal seismic attributes (differential interval velocity and amplitude variation with offset and azimuth) for natural fracture detection. The second goal was to use sufficiently close receiver group spacing to evaluate the small, subtle faults in the survey area. The budget allowed for a 4.5 square mile multi-azimuth seismic survey, with receiver group spacing of 220 feet. Western Geophysical performed the survey in April, 1996 using a total of 944 receiver stations and four 47,000 pound (hold down weight) P-wave vibrators. The processing of the data was performed by Western Geophysical and involved pre-processing/editing, signal processing, preliminary stack, 3-D refraction statics, 3-D velocity analysis, 3-D residual reflection statics, second pass of 3-D velocity analysis, second pass of 3-D residual reflection statics, azimuth gather preparation, detailed analysis of five azimuth gathers to determine azimuth parameterization, and separation of the data into two azimuth volumes.

The interpretation of the seismic data showed that a series of northwest-oriented subtle reverse faults exist in the Rulison Field. Incorporation of these fault systems into Advanced Resources geomechanical model (FSD) delineated a series of local natural fracture clusters in the Rulison Field, **Figure 1-3**. These pockets of local natural fracture clusters correlate with higher well productivity and permeability, particularly in the southern Rulison Field area. The geomechanical approach was subsequently applied in the Mamm Creek Field, east of Rulison Field, and showed a

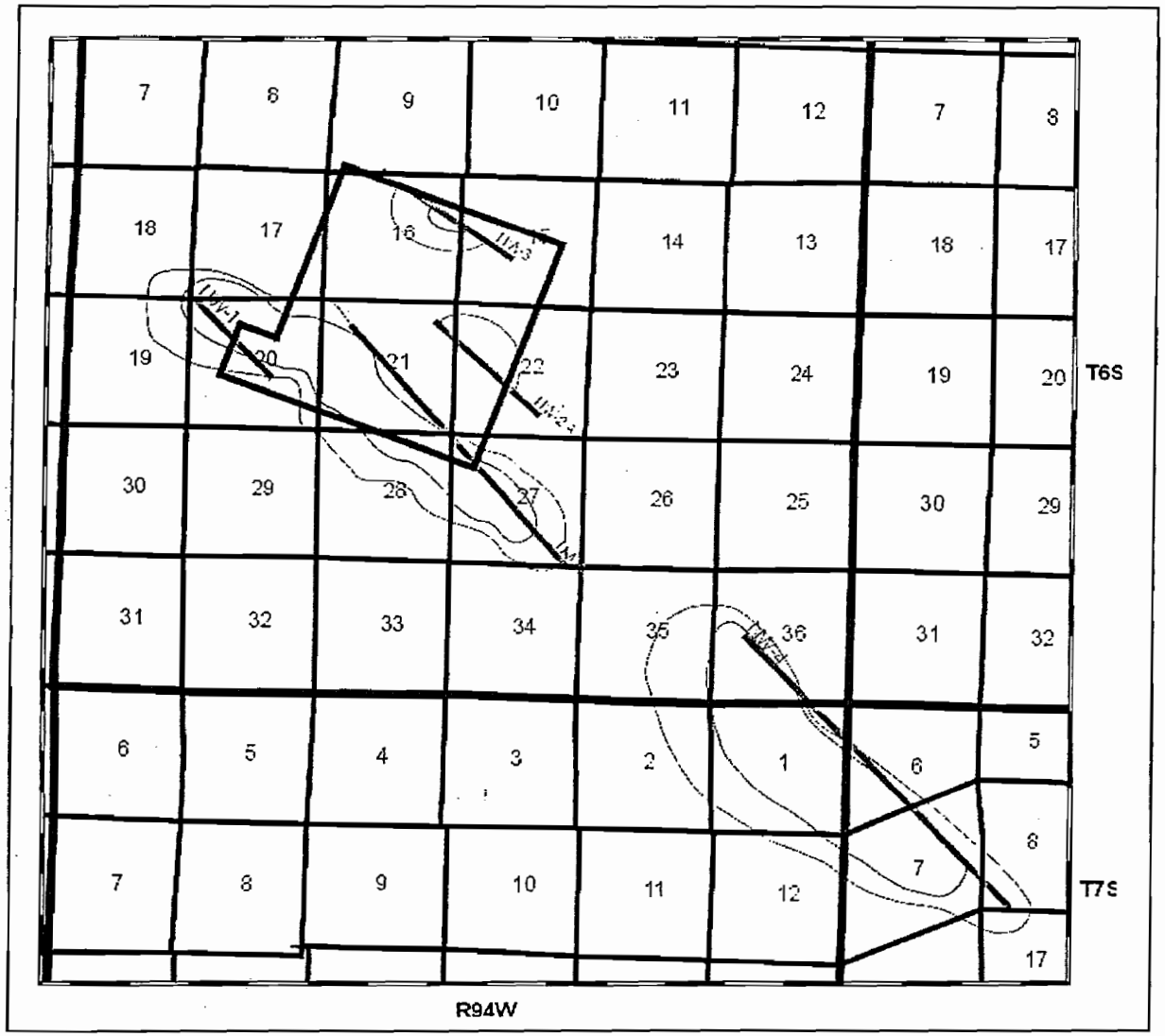


Figure 1-3. Regions Identified by Geomechanical Model as Areas of Fault-Related Fracture Clusters, Rulison Field.

favorable correlation between the local natural fracture clusters and well productivity (permeability), **Tables 1-1, 1-2 and 1-3**.

During Phase Three, the 3D multi-azimuth seismic data was examined for P-wave velocity anomalies that may indicate the presence of open natural fractures. Initial examination of the data identified modest velocity anisotropies in NW and NE orientations. Thus, the data volume was divided into two sets and interval velocities were calculated for the section between the top of the gas-saturated Mesaverde and the top of the Cameo coals. The seismic attributes showed several areas of modest velocity anisotropy (ratios of >1.04 and <0.96) that might indicate the presence of open natural fractures. (For more detailed information, see DOE/FETC's "Detection and Analysis of Naturally Fractured Gas Reservoirs" in CD-ROM format.)

PHASE FOUR: PERFORMANCE REVIEW OF NATURAL FRACTURE DETECTION TECHNOLOGY. Phase Four involved documenting the major insights and observation gained from the Project and evaluating the performance of alternative approaches to natural fracture detection at Rulison and Mamm Creek (Fields) as discussed below:

Observations. Three observations of particular relevance to understanding naturally fractured, low permeability reservoirs were gained from the Project:

1. The first observation is that local, fault-related natural fracture clusters provide the essential overprint to the regional natural fracture system, creating the higher permeability "sweet spots" in otherwise "tombstone tight" reservoir rock.

2. The second observation is that these local, one to ten sections in size, areas of fracture enhanced permeability appear to exist pervasively in the low permeability natural gas reservoirs of the Rocky Mountains.

3. The third observation is that the randomness of well behavior in fractured reservoirs is due to random well location selection not fundamental geology.

Table 1-1
Results of North Rulison 3D Natural Fracture Detection Technology Test

	Wells Inside Local Fracture Cluster	Wells Outside Local Fracture Cluster
No. Wells	41	55
Average Permeability (μd)	12	6
Average Net Pay (ft)	320	290
Average EUR/Well	2.3 Bcf	1.3 Bcf

Table 1-2
Results of South Rulison 2D/3D Natural Fracture Detection Technology Test

	Wells Inside Local Fracture Cluster	Wells Outside Local Fracture Cluster
No. Wells	12	23
Average Permeability (μd)	17	6
Average Net Pay (ft)	270	220
Average EUR/Well	3.4 Bcf	1.0 Bcf

Table 1-3
Results of Mamm Creek 2D Natural Fracture Detection Technology Test

	Wells Inside Local Fracture Cluster	Wells Outside Local Fracture Cluster
No. Wells	15	16
Average Permeability (μd)	13	6
Average Net Pay (ft)	190	200
Average EUR/Well	1.7 Bcf	0.8 Bcf

Review of Performance. The performance of the alternative technologies was assessed using the criterion -- reliability and costs in detecting fault-related naturally fractured areas in advance of drilling.

1. **Shear-Wave Seismic**. This approach, while showing considerable research promise, is extremely costly and poses major implementation and interpretation challenges.

2. **Seismic Attributes**. This approach uses seismically derived data, such as ratios of interval velocity and AVO, to directly detect the location of natural fractures. Fundamental problems remain to be solved for this technology, such as isolating the effects of areal and vertical changes in formation lithology and uncertainties in relating seismic anisotropy to well productivities. (A low velocity anisotropic signal may indicate an area with few or no fractures or one with intense, multi-directional natural fractures.)

3. **Geomechanical Approach**. This approach combines seismic and a geomechanical model (such as ARI's Fault Stressed Domains (FSD) model) to predict the location, orientation and aperture of natural fractures. Seismic data provides the essential input data on fault geometry, displacement and style to the geomechanical model.

Summary Evaluation. All three natural fracture methods were considered in the Rulison Field test area. The shear-wave seismic approach was eliminated because of near-surface noise problems at the test site and high costs. The seismic attributes approach was tested using a high-fold, multi-azimuth seismic shoot. While a research quality data volume was acquired, processed and interpreted, the results were ambiguous and highlighted the fundamental research problems that still exist with this technology.

The dominant natural fracture detection approach that emerged from the Rulison Field test was geomechanical (fault and stress) modeling. This is a low cost approach because P-wave seismic and a combination of 2D and 3D seismic data can be used for input data. However, sophisticated processing (pre-stack/post-stack time to depth migration) is essential and considerable emphasis must be given to interpreting the three-dimensional geometries of subtle faults. Also, a fault and rock

deformation model is required to translate the seismic inputs into naturally fractured, "sweet spot" area predictions.

PHASE FIVE: APPLICATION OF GEOMECHANICAL APPROACH AT TABLE ROCK FIELD. Phase Five of the Project involved the application of the geomechanical approach to natural fracture detection at Table Rock Field, eastern Greater Green River Basin, **Figure 1-4**. (See Chapter 2 for further discussion of the Table Rock natural fracture detection study.)

Prior to drilling the Rock Island horizontal well, a geomechanical analysis was performed for the area to ascertain whether the location of the well was appropriate for testing a fault-related natural fracture play. If appropriate, the second step was to determine the optimal orientation of the horizontal well. The geomechanical analysis began with a regional fault mapping of the area using existing 3D seismic data. Selected portions of the Table Rock and Continental Divide Phase II 3D surveys were post-stack depth converted for fault mapping and for seismic coherency analysis.

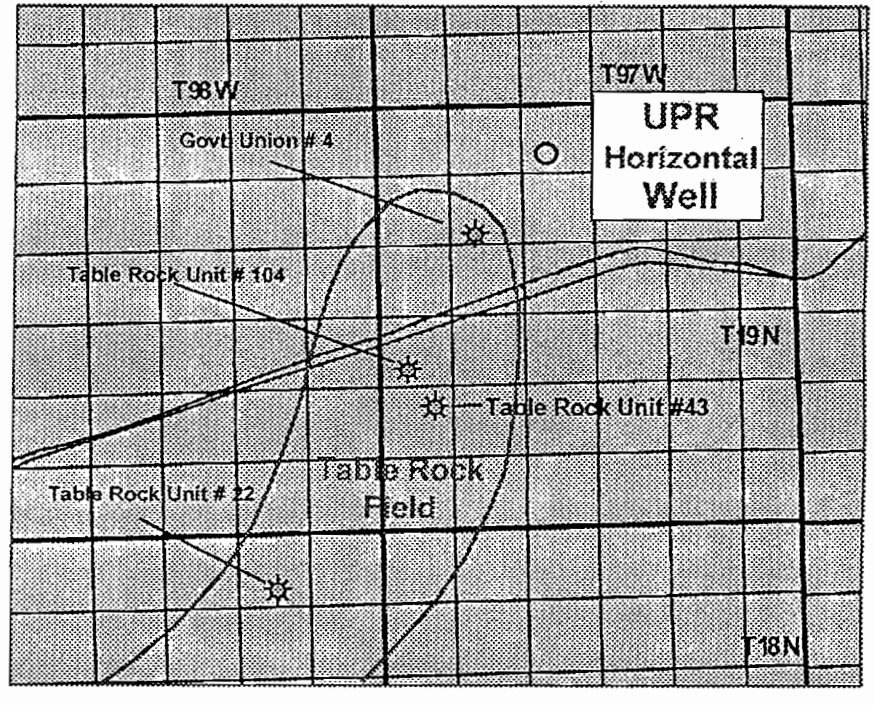
The major fault systems in the area were mapped from the basement break to the up section terminus. The Table Rock thrust system east and north of the field is comprised of two major faults, a thrust fault that trends N30°E and an oblique reverse-strike-slip fault that trends approximately N60°E. For the 12 township regional anlaysis, only the connected geometry of the thrust and strike-slip faults were used in the geomechanical model and the northern continuation of the thrust was ignored.

The areal locations of shear fractures calculated by the geomechanical model are consistent with successful production from the Frontier Fm. Inside the area of local fracture clusters, the Govt. Union #4 well produces 6,000 Mcfd and the Table Rock #104 IP'd at 4,300 Mcfd. Outside the area, the initial tests of Table Rock Unit #22 and #43 wells were discouraging and the wells are shut-in at the Frontier interval. The Rock Island 4H location is at the northeastern extent of the stress concentration. The model predicted that the well will encounter shear fracture orientations at N25-30°W and N85-90°W.

Deep, High Risk Frontier Fm. Reservoir

- *15,000'; 270° F; 10,000 psi*
- *Unsuccessful exploration well at Frewen*
- *World record tight gas horizontal well*

Table Rock Field Area



Greater Green River Basin

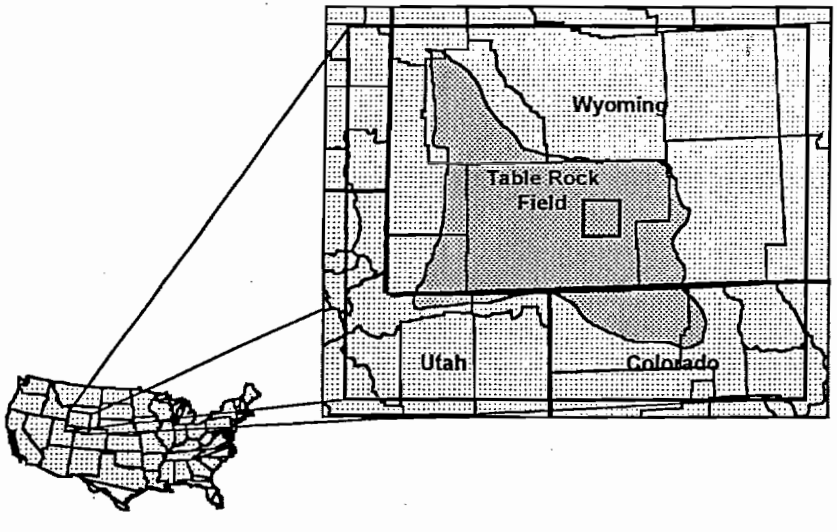


Figure 1-4: Table Rock Field Case Study, Frontier Fm., Green River Basin

The geomechanical model was next run for local natural fracture analysis, appropriate for prospect delineation, in an 80 section area around the Rock Island 4H horizontal well. A full 3D data set was extracted to map the local fault geometry. The data was again depth-converted to map faults in space rather than time and coherency processing was applied to optimize fault identification. Subtle faults and complex geometry of the main thrust and strike-slip system were revealed from coherency filtering.

The detailed mapping of the geometry of the fault systems permitted the prediction of local natural fracture development. A geomechanical model was run again with all the smaller faults included. The results showed that the Rock Island 4H well occupies an area between two small faults and appears to have hit a zone of enhanced stress concentration, **Figure 1-5**. After completion, the Rock Island 4H well tested at 12 to 20 MMcf and currently produces at 13 MMcfd.

PHASE SIX: GREATER GREEN RIVER BASIN PARTITIONING STUDY. Phase Six of the Project involved a Partitioning Study of the Greater Green River Basin (GGRB) to identify the in-place and technically recoverable natural gas resources in the overpressured low permeability Frontier and Mesaverde Formations, **Table 1-4 and Figure 1-6**. As part of this, an in-depth examination was made of the Green River Deep partition and the location of the UPR/DOE Stratos test well in the deep Frontier, as discussed in ***Appendices C and D***. (See Chapter 3 for further discussion of the GGRB Partitioning Study).

TECHNOLOGY TRANSFER. Finally, a series of presentations, workshops and technical papers have been prepared during the final project year to help transfer the technology to interested parties and potential users. These materials are provided in ***Appendices A and B***.

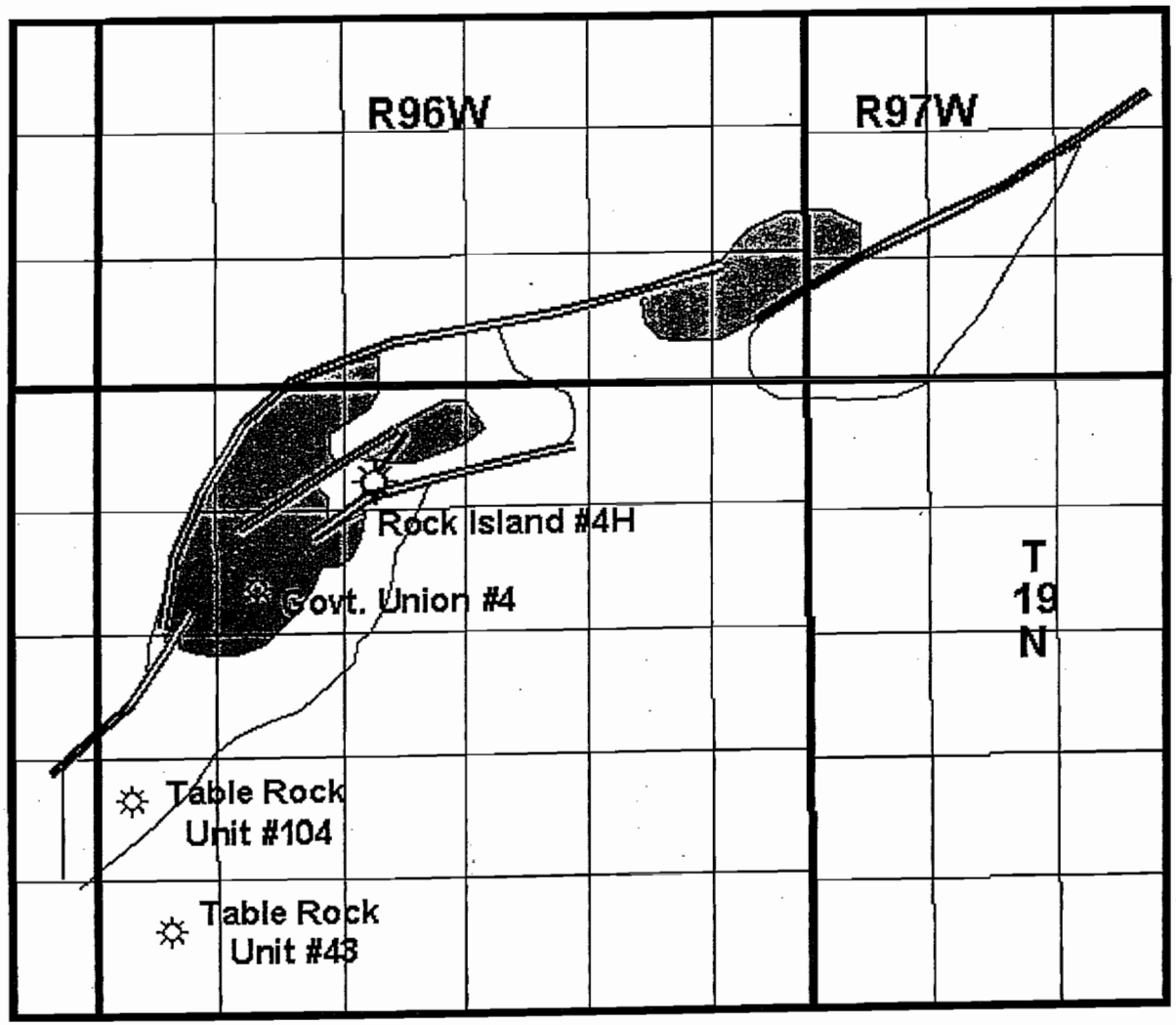


Figure 1-5. Stress Concentrations and Expected Fault-Related Natural Fracture Development as Calculated by the Geomechanical Model in the Vicinity of the Rock Island 4H.

Table 1-4
Overpressured Natural Gas Resources, Frontier and Mesaverde Fms., GGRB

Basin Partitions	Gas-in-Place (Tcf)		Technically Recoverable Gas Resources (Tcf)			
			Base Case		Advanced Case	
	Frontier	MV	Frontier	MV	Frontier	MV
Cherokee Arch	2	13	0.4	2.5	0.6	3.5
Dad Dix	2	-	0.2	-	0.3	-
East Sand Wash	7	37	0.7	3.3	1.3	4.7
East Washakie	4	23	0.4	2.1	0.6	3.0
Farson Deep	24	80	2.6	6.0	4.6	8.5
Green River Deep	24	-	3.1	-	5.5	-
Hoback	29	197	2.4	11.2	4.2	15.8
Pinedale	17	238	2.6	19.6	4.7	27.5
Red Desert Deep	9	10	0.6	0.8	1.0	1.1
Red Desert	44	181	4.0	12.8	7.0	18.4
Sand Wash Deep	8	89	1.3	13.1	2.3	18.4
Vermilion	11	-	1.0	-	1.8	-
Wamsutter Arch	7	63	1.1	7.0	1.9	9.9
Washakie Deep	12	84	1.3	8.4	2.4	11.9
Washakie West	4	-	0.8	-	1.4	-
West of Moxa Arch	12	-	0.9	-	1.7	-
TOTAL	**216**	**1,015**	**23**	**87**	**41**	**123**

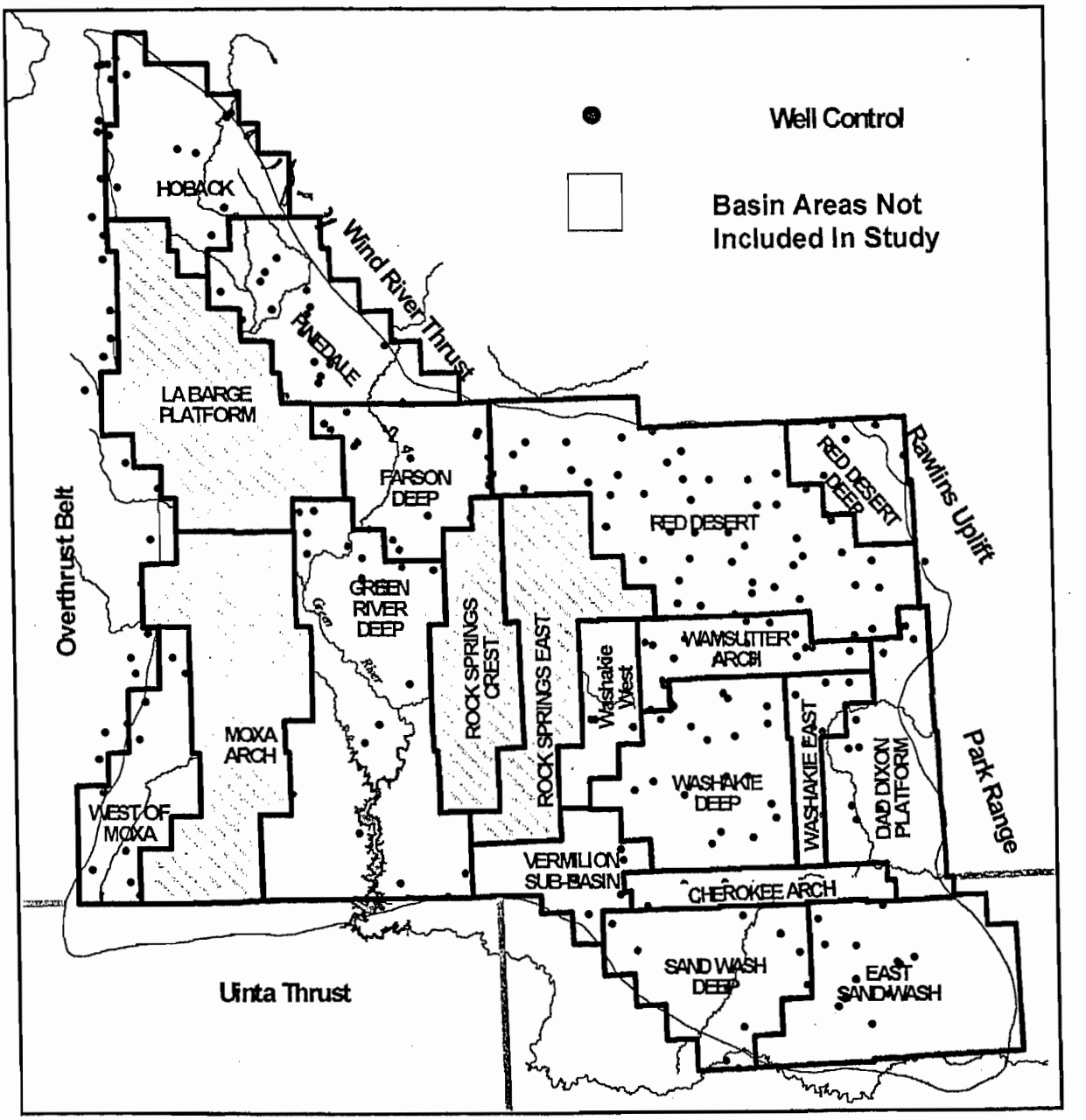


Figure 1-6. Greater Green River Basin Partitions (Overpressured Mesaverde and Frontier Formations)

CHAPTER 2
Finding Local Fault-Related Natural Fracture Clusters in Low Permeability Fractured Reservoirs: Geomechanical Based Exploration Technologies

Introduction

Low permeability fractured reservoirs contain vast natural gas resources, particularly in the Rocky Mountain gas basins. These reservoirs already provide 4.3 Tcf (23%) of annual domestic natural gas production, and will need to play an increasingly important role in meeting future U. S. natural gas demand. The primary obstacles to the economic exploitation of these vast resources are the difficulties in successfully exploring for and efficiently developing the productive, naturally-fractured "sweet spots" and in these basins.

Historically, industry has found the detection of natural fractures, prior to drilling, to be a major challenge. As a result, low permeability plays have often been approached as a statistical play where the regional naturally fractures of the reservoir are assumed constant and the primary risk is encountering thick pay with sufficient gas charge. In addition, horizontal or deviated wells have been used to increase the statistical probability of intersecting regional natural fractures. While pragmatic, these approaches to low permeability reservoir development have often resulted in low productivity wells and poor economic margins.

It is now widely agreed that improving the exploration and development success in low permeability gas reservoirs requires technology that can reliably identify the intensely naturally fractured areas of a gas play. Recent drilling in the Rocky Mountain basins confirms that a local natural fracture overprint on the regional natural fracture system is the essential condition for highly productive wells in low permeability gas reservoirs.

This Chapter will: (1) introduce the relevance of local natural fracture systems to low permeability gas exploration and development; (2) review the most promising technologies for detecting local naturally fractured settings in advance of drilling; and, (3) present three case studies

where the highly productive areas in otherwise low permeability reservoirs (containing the essential overprint of local natural fractures on a regional fracture system) have been delineated with seismic and geomechanical based natural fracture detection technology.

Regional and Local Natural Fractures

Natural fractures are formed in reservoir rock under a variety of conditions including accommodation of overburden load due to burial, release of high pore pressures resulting from hydrocarbon generation, and accommodation of lateral deviatory stresses due to basin tectonics. While a complex history is associated with the origin of natural fractures in any given basin, the resulting natural fracture sets can be divided into two distinct types -- regional fracture systems and local ("tectonic") fracture clusters.

Regional Fracture Systems

Fractures developed in undeformed strata are usually referred to as regional fracture systems (Babcock, 1973). Regional natural fractures are laterally pervasive, consistent in orientation, and generally vertical in extension (see Lorenz et al., 1991a, for an overview on the formation of regional natural fractures). Due to their consistency, regional fractures have been employed as regional stress indicators assuming a straightforward relationship between their development and the principal orientation of the regional stress field in a basin. Regional natural fractures have been shown to generally occur at micro-scale and have received considerable study in cores and basin outcrops.

For low permeability formations, regional fracture systems have been shown to be important for understanding a reservoirs baseline permeability (Lorenz, et al., 1991b). One problem with regional natural fracture systems is that they create highly anisotropic horizontal permeability due to the parallel pattern of occurrence with few cross fractures. This anisotropy illustrates one of the problems when only regional natural fractures systems exist in a low permeability setting -- the lack of connectivity in regional fracture systems severely limits reservoir contact using vertical wells. Thus, it is often necessary to drill a deviated or horizontal well to encounter a larger set of regional fractures and to capture their contribution to enhanced permeability. A second problem with regional natural fracture systems is that these fractures are often short, millimeters in length, with insufficient

fracture width to provide adequate enhancement to an otherwise "tombstone tight" reservoir matrix, even when using a horizontal well.

Local Fracture Clusters

Local fracture clusters are developed in deformed strata principally near and around faults and folds. In addition to extension fractures, local fracture clusters are often comprised of sheared fractures -- natural fractures that are essentially small faults with micro- to macro-scale displacement along the plane of the fracture. In outcrop, local fracture clusters show directional deviations and complex superposition over the regional fracture set (Engelder, 1987). Local fracture development can be explained by employing a geomechanical characterization of stress concentrations developed around larger structures. Both theory and observation support the geomechanical aspect of local fracture development and provide confidence that a scientifically-based technology can be developed to detect local fracture clusters (see Rispoli, 1981, and Olsen and Pollard, 1989).

The highly variable spatial occurrance of permeability in low permeability reservoirs provides evidence for local fracture control over production. Furthermore, reservoirs have been observed to produce better near fault systems and related folds (e.g. Austin Chalk of the Gulf Coast, and Frontier Fm. of the Greater Green River Basin). Natural fractures near these tectonic fractures have commonly been called "fault-related" or "fold-related" fractures. The enhancement of reservoir permeability by local fracture clusters results from three conditions interest to local fractures -- increased reservoir fracture connectivity provided by the local fracture overprint on the regional system, longer natural fractures with increased width, and a reduced sensitivity of the fractures to changes in stress (as reservoir pressure is reduced near the wellbore) due to the irregular orientation and surfaces of these local fracture sets.

While regional fracture systems are undoubtedly important in the development of low permeability reservoirs, it is the local fracture overprint that creates the highly productive "sweet-spots" in the reservoir (**Figure 2-1**). Identifying a fractured reservoir's "sweet-spots" in advance of drilling has been the objective of many exploration programs and has been the focus of considerable R&D. One of the most promising aspects of this research has been the development of natural fracture detection technology using seismic and geomechanics.

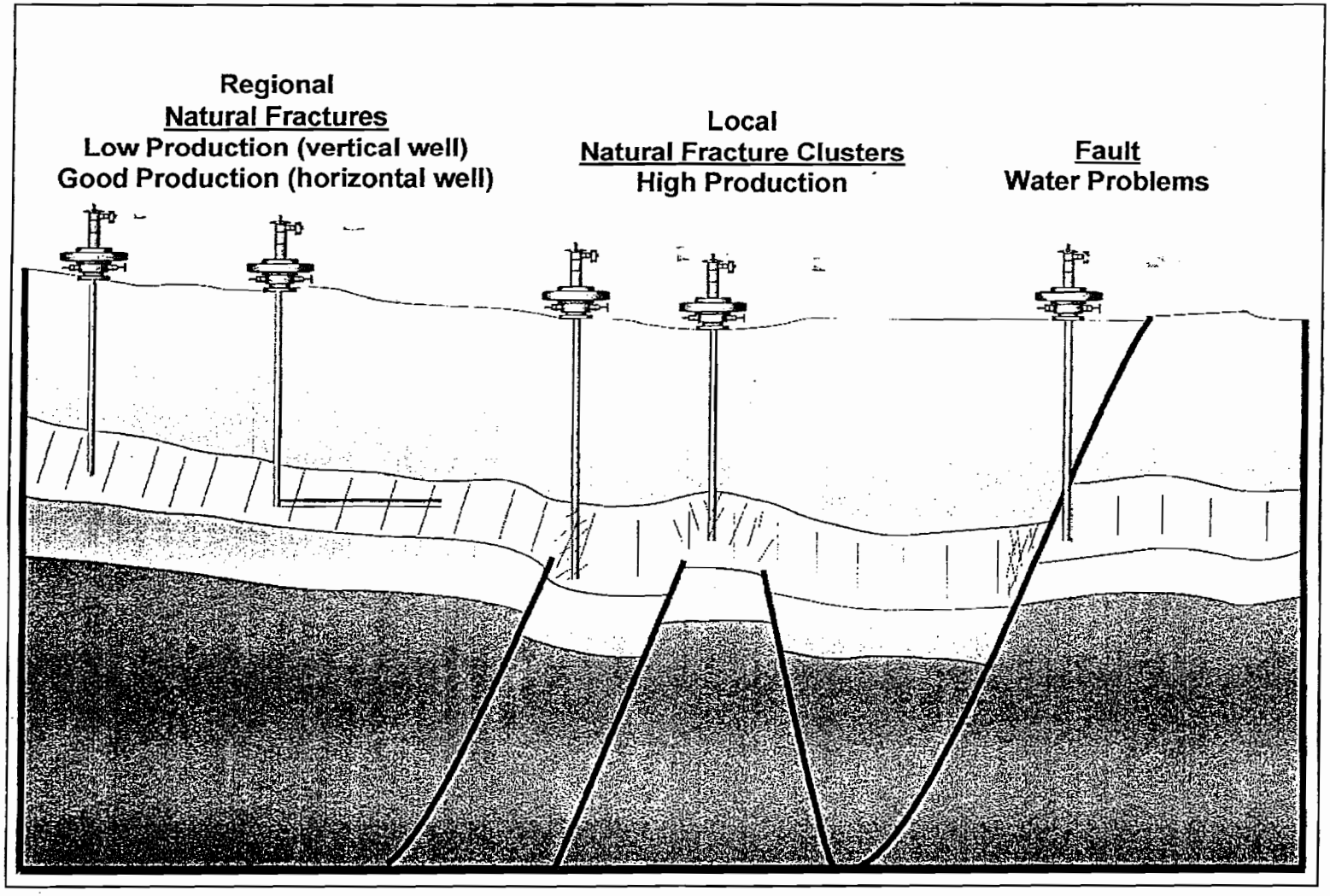


Figure 2-1. Natural Fracture Settings and Their Relationship to Low-Permeability Gas Production.

Natural Fracture Detection Technologies

The detection of natural fractures in the subsurface is generally ranked as the highest priority technology need in exploring and developing low permeability reservoirs. Great advances have been made in borehole based technologies such as imaging logs, borehole sonic and cross-well tomography. The greatest challenge, however, is the development of low cost technologies that can detect natural fracture systems in advance of drilling and beyond the borehole, particularly for exploration drilling.

The Direct Seismic Approach

Seismic methods that directly image natural fractures are built on the assumption that natural fractures cause directional variations (azimuthal anisotropy) in seismic waves. Both shear (S-) and compressional (P-) waves are theoretically sensitive to the presence of fractured reservoirs. Recent case studies show some promise in specific applications of this technology, as discussed in the summary of the assessment of direct seismic methods and case studies final report (DOE, 1998).

Shears (S-)waves are more sensitive to discontinuities in the rock fabric than are compressed (P-)waves and therefore are considered superior for fracture detection. In a perfectly isotropic medium -- one in which wave propagation is the same in all directions -- shear motion in one direction would be recorded only on a geophone with a similar orientation. Seismically anisotropic materials exhibit shear wave splitting, where the shear wave breaks into two new waves, traveling along the same ray path. In a simple anisotropic medium consisting of parallel natural fractures, the slow shear wave has particle motion perpendicular to cracks, and the fast shear wave vibrates in the plane of the cracks. S-waves can map fracture density and orientation and are insensitive to fracture contents (such as gas). Processing is complex, and the acquisition requires horizontal vibrators. Because of the relative complexity in S-wave acquisition and processing, these methods are much more expensive (approximately five times) than P-wave surveys.

Compressional (P-) waves are less sensitive to fractures than S-waves, but do respond to fracture contents and can also be used to directly image natural fractures. P-wave surveys can be adapted to measuring anisotropy simply by maintaining sufficient live receivers for good all-azimuth

coverage. Azimuthal variations in travel times (velocities) can be used to estimate relative fracture density and fracture azimuth, providing directly measureable seismic attributes. Without sufficient fold, however, signal-to-noise decreases rapidly. However, the seismic attribute method has severe limitations in that it is not robust, can provide false or no anomalies in the presence of dense and diversely oriented natural fractures, and suffers in resolution in the presence of complex sand/shale lithlogic variations.

The greatest current weakness in the direct seismic approach for natural fracture detection is the lack of a unique solution, particularly when a reservoir contains a complex geometry of natural fractures. This is especially the case when local naturals fracture clusters overprint the regional fracture set. When a reservoir contains numerous sets of natural fractures, their complex geometry reduces seismic anisotropy and may effectively provide a no-anomaly signal for the most prospective ("sweet spot") portion of a low permeability reservoir.

Geomechanical Approach

While seismic technology for direct detection of natural fractures is still promising, the lack of a unique solution in current methods provides motivation to develop alternative technology that works in conjunction with seismic analysis. Given that larger structures such as faults create secondary local fracture clusters, the geometry and deformation history of these faults provides the necessary information for rigorous geomechanical modeling and natural fracture detection.

Detailed structural interpretation of 2D and 3D seismic data provides the required input for the geomechanical model. Stress concentrations around the major structures are calculated from observed slip across the faults or the paleostress regime if slip vectors are not available. The derived principal stresses can then be used to calculate the local failure criteria, such as the maximum Coulomb shear stress for shear failure (sheared fractures) or the maximum tensile stress for tensile failure (extensional fractures). Since local stresses vary around major faults, these failure criteria define where secondary sheared and extensional fractures may have formed. This enables the geomechanical model to predict the occurrence and location of local natural fractures and regions of enhanced permeability.

The geomechanical approach not only allows identifying the expected areas of local natural fracture clusters in a low permeability gas play, but also enables calculating the orientation and the intensity of these local natural fracture clusters. The method can be used as a stand-alone application or can be used in conjunction with direct seismic technologies.

Field Case Studies

The application of the geomechanical approach for identifying and predicting the location of fault-related natural fracture systems is discussed in three field studies -- Rulison, Mamm Creek and Table Rock fields.

Rulison Field, Piceance Basin

The Rulison Field in the Piceance Basin, Colorado provided the initial evidence that local fracture systems were responsible for the reservoir's "sweet-spots". It also served as the site for the first field test of the geomechanical approach.

Background. The Piceance Basin in western Colorado is a complex basin formed by Laramide tectonism during late Cretaceous through Paleocene time. The basin is the site of a large basin-center continuous gas deposit within the sandstones of the Mesaverde Williams Fork Fm **(Figure 2-2)**.

Updated gas-in-place estimates for the Williams Fork sandstones were prepared using a stratigraphic study of the southern Piceance Basin, advanced well log analysis on 30 key wells, and reservoir data from operators. Based on this, it was estimated that 311 Tcf of gas-in-place exists in the Williams Fork tight lenticular sands of the Piceance Basin (plus 75 Tcf of gas-in-place in the Cameo and Coal Ridge coals). Of this amount, approximately 10 Tcf of gas-in-place is located in the two townships that currently define the Rulison Field.

In the Rulison Field, the Williams Fork Fm is a 3,000 to 4,000 feet thick sequence of tight

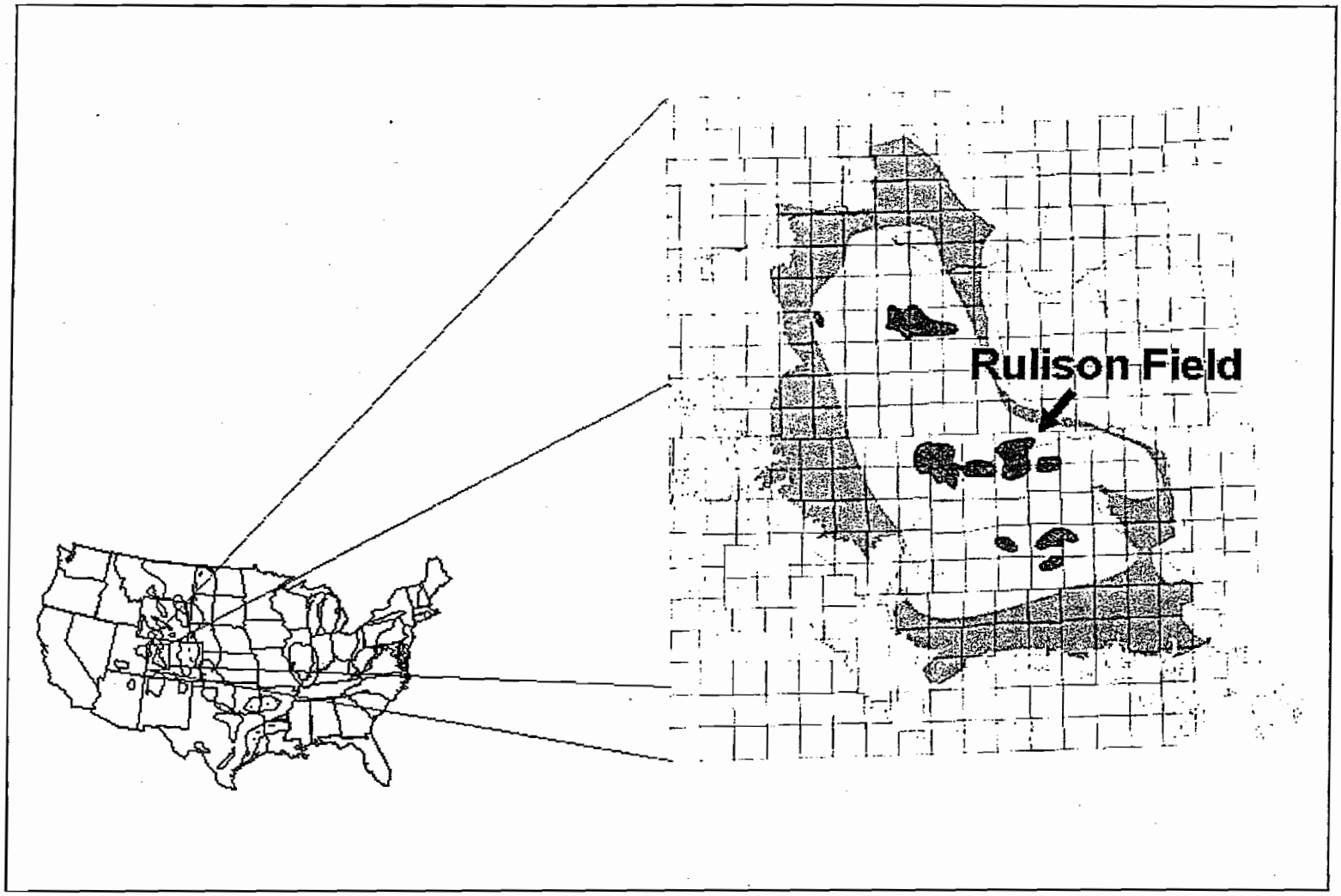


Figure 2-2. Location of the Rulison Field Site.

sands, shales and coals. The two sections of interest are the lower Williams Fork interval of coals and sands (locally, Cameo Formation) that lies on top of the Rollins Sandstone and the upper Williams Fork interval (locally, Mesaverde Formation) with a top at the Cretaceous-Tertiary unconformity. The sands in these two intervals are part of a basin-center gas trap, with overpressured gas down-structure from more permeable water-bearing sands. The fluvial sandstones are point bar deposits, stacked into a composite of meander-belt reservoirs, each 20 to 60 feet thick and 500 to 1,500 feet wide, with considerable internal discontinuities and compartmentalization. A series of excellent publications and articles are available on the Mesaverde geologic setting, stemming from past Department of Energy (DOE) and Gas Research Institute (GRI) sponsored geologic studies (Kuuskraa, 1997) and from DOE and GRI sponsored work at the MWX field laboratory and test site in the Rulison Field (Lorenz, 1990).

Reservoir and Natural Fracture Characteristics. Due to the presence of authigenic clays, carbonate cement, and quartz overgrowth, the sandstones of the Williams Fork Fm. have low matrix permeabilities, on the order of one microdarcy. Net pay and gas filled porosity are favorable, providing a rich gas package of $\pm$140 Bcf per square mile. Historically, operators had assumed that net pay (and its deposition) controlled gas production in these tight, lenticular sands. However, completed net pay and expected ultimate gas recovery per well showed little correlation, indicating that another reservoir property, such as natural fractures, controls the productivity of this gas play. Subsequent analysis showed that an excellent correlation exists between the product of permeability and completed net pay (kh) and estimated ultimate recovery per well. This provided confidence that the most significant reservoir property to characterize is natural fracture-related permeability.

Exploration History and Recent Drilling Results. Starting in 1993, the primary Rulison Field operator (Barrett Resources) began an active program to fully develop the field by in-fill drilling and recompleting sands left behind pipe. The recompletion program was particularly valuable for defining the true productivity of these stacked, lenticular low permeability sands. With the increased drilling density, the variability in reservoir performance and permeability became fully apparent. This variability was primarily ascribed to the presence or absence of local fracture networks.

Step-out drilling was started at Rulison Field in mid-1996 to extend the field to the southeast where operators had initially encountered a pocket of highly productive wells. However, the traditional step-out approach to field expansion resulted in a mix of productive, marginal and non-productive gas wells. A major reason for these mixed results was the rapid variability in permeability and natural fractures in the area, with wells less than a mile apart differing five to tenfold in productivity and estimated ultimate recovery (**Table 2-1**).

Table 2-1. Comparison of Three Wells in the South Rulison Field

	Fusilier 2-11 (Sec. 2, T7S, R94W) (Compl. 7/97)	**Savage Fed 1-3 (Sec. 1, T7S, R94W) (Compl. 2/95/Rec. 10/96)**	**Federal RU 34-6 (Sec. 6, T7S, R93W) (Compl. 12/96)**
EUR	0.9 Bcf	4.5 bcf	0.3 Bcf
NET PAY	300 ft.	322 ft.	285 ft.
Porosity	9.8%	10.60%	12.2 %
Permeability	4 μd	14 μd	2 μd

Fault Mapping and Geomechanical Model. Advanced Resources tested the geomechanical approach in the Rulison Field, using seismic data and a geomechanical model to identify areas of stress concentrations and local natural fracture clusters due to local faults. Inputs to the geomechanical model were limited to information that was directly observable -- fault geometry and displacements derived from the 3D (and 2D) seismic analysis in the Rulison Field area. Using a criterion of the maximum tensile failure, regions where tensile stress concentrations occur were mapped (**Figure 2-3**). These regions represent the location where it is more likely that fault-related natural fractures occur.

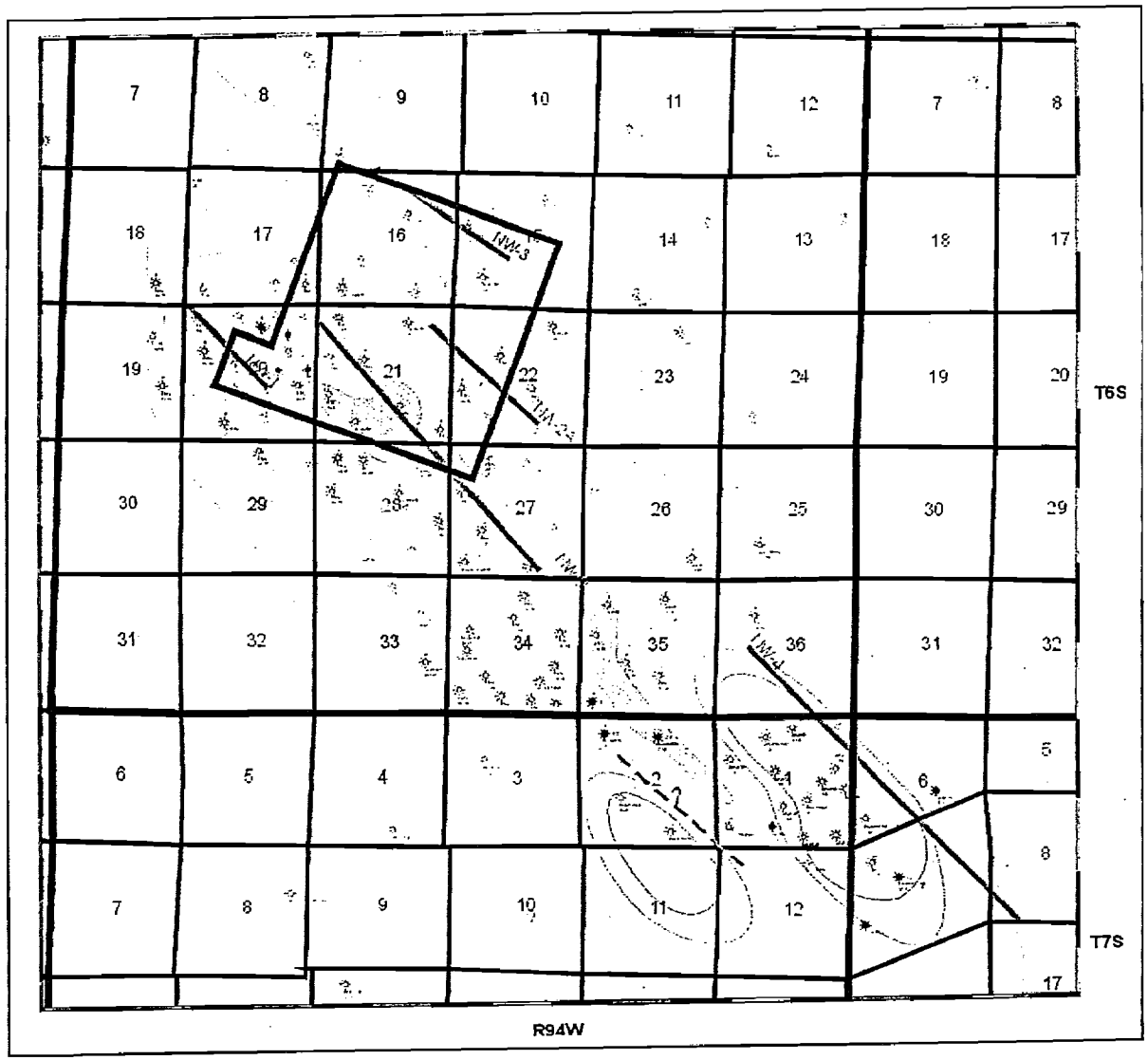


Figure 2-3. Calculated Permeability of the Rulison Field.

As a first step, Advanced Resources, with sponsorship by DOE/FETC and participation by Barrett Resources and Western Geophysical, acquired a high-resolution 3D seismic survey over Rulison Field. (This survey was also used to assess direct seismic detection of natural fractures using multi-azimuth P-wave analysis.) The data was used to map the local fault system in the field. The high-resolution 3D seismic data revealed numerous small reverse faults that had been not previously mapped. The fault trends correlated loosely with high gas productivity trends and provided support for fault-related natural fracture systems. The area's major faults were mapped using both 3D and 2D seismic data. The geometry and relative displacements of these faults provided input into the geomechanical model.

Advanced Resources' geomechanical model (FSD) was used predicted areas of elevated permeability from the overprint of local natural fracture clusters on the regional system. Well production in the northern portion of the Rulison Field correlated generally with predicted natural fracture clusters. The analysis in the northern Rulison Field could benefit from more complete fault mapping and more complex fault system inputs to the geomechanical model in the area.

The subsequent application of the geomechanical model in the south-east extension of the Rulison Field showed that well performance in this area correlated extremely well with predicted areas of local natural fractures (**Table 2-2**). In the southern Rulison Field, a significant reverse fault appears to have created a large pocket of local natural fracture clusters, enhancing the area's productivity.

Table 2-2. Comparison of Southern Rulison Field Well Performance for Regions of Local Fracture Development and Regions Where Primarily Regional Fractures Exist

	Wells Inside Local Fracture Clusters	**Wells Outside Local Fracture Clusters**
No. Wells	12	23
Average Permeability (md)	17	6
Average Net Pay (ft.)	266	224
Average EUR/Well (Bcf)	**3.4**	**1.0**

Structural analysis in the Rulison Field confirms that local fault-related natural fracture clusters are responsible for the increase in permeability. The field test also provides confidence that a geomechanical approach can be used to quantitatively establish the location, intensity and orientation of these local natural fractures.

Table Rock Field, Greater Green River Basin

Background. The Table Rock Field is the site of a field based research and development partnership between Union Pacific Resources and DOE/FETC (**Figure 2-4**). The primary goal of this project is to develop technology that could transform the very large 275 Tcf tight sand resource in the deep Frontier Fm. into a technically and economically feasible gas play. Horizontal drilling technology was selected as the primary means to test the Frontier gas play. The field site provided an opportunity to test and further develop the geomechanical approach to mapping fault-related natural fracture systems in a different basin and geologic setting.

Exploration History and Recent Drilling Results. Texaco discovered the Table Rock Field in 1946. Production from conventional reservoirs is limited by structural closure of the thrust-related anticline.

Exploring the Frontier Fm. in the Eastern Greater Green River Basin and at Table Rock has had varying degrees of success and failure. The Table Rock #104 well was initially tested at 4.3 MMcfd from the Frontier Fm. though it currently produces at only 300 Mcfd. Two other attempts to produce from the Frontier Fm (wells TRU #22 and TRU #43) did not meet with success and were shut-in. Production remained minimal for the Frontier Fm. until the drilling of the Govt. Union #4 well. Though the primary objective of this well was a deeper target, the Frontier Fm. had a major gas show and the well was perforated in the section. Production from the Govt. Union #4 is at 6 MMcfd with little decline.

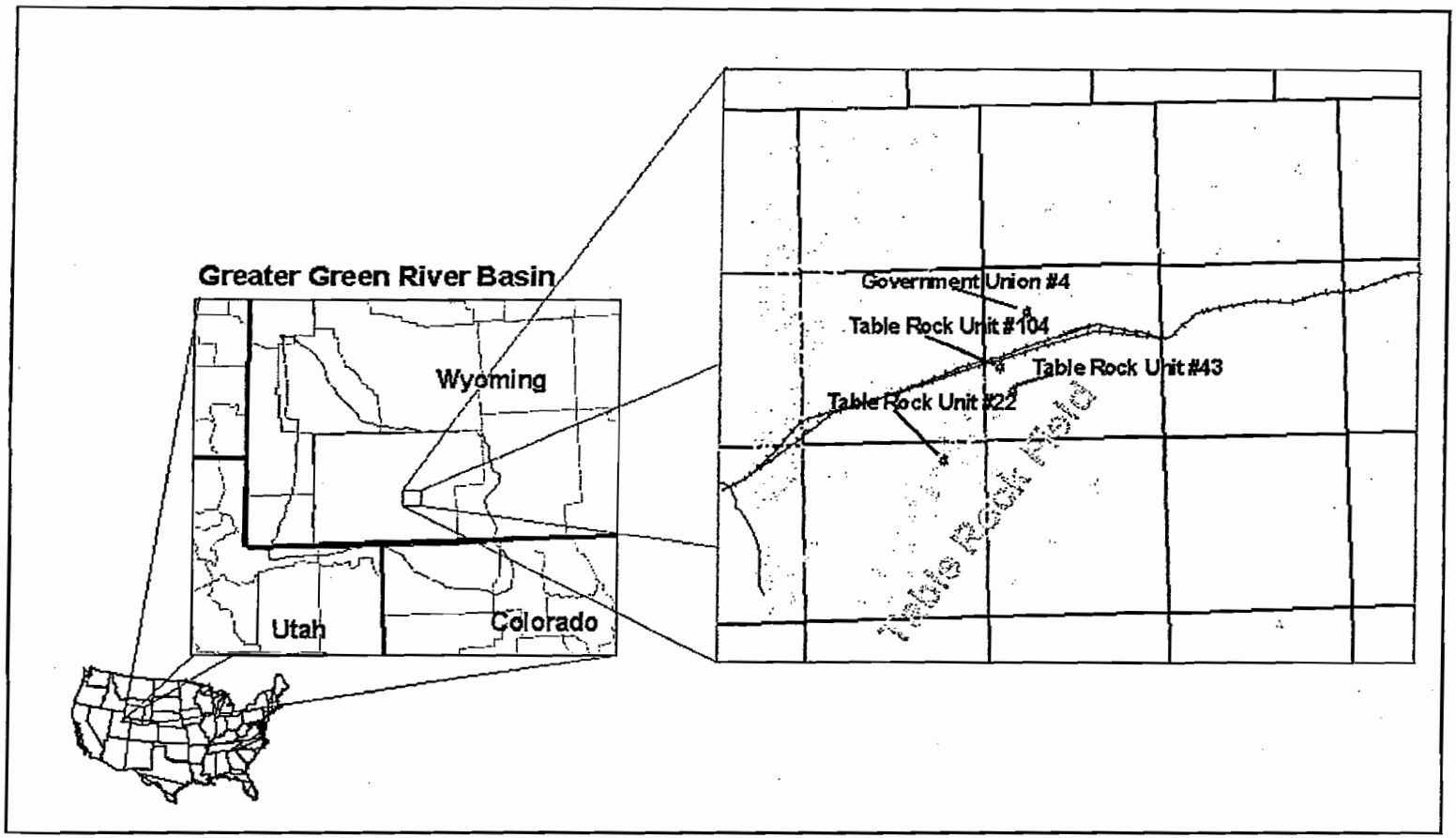


Figure 2-4. Location of Table Rock Field Site.

Two townships east of Table Rock Field, Amoco had previously tested the deep potential of the Frontier Fm. Amoco drilled the Frewen Deep #4 well, encountering the Frontier Fm. at approximately 18,250 feet. From core observations, it was determined that the well encountered large open natural fractures. In spite of the presence of open natural fractures, the well produced at low gas rates and was abandoned.

The latest development in the search for an economic play in the Frontier Fm is the UPR Rock Island 4H well. The horizontal well is an offset to the producing Govt. Union #4 well, approximately 1.5 miles to the northeast, and includes a horizontal leg of 1700 feet. The well has one of the highest gas flow capacities (15 to 20 MMcfd) for the Frontier Fm. in the Greater Green River Basin. It currently is on line and producing at 13 MMcfd.

Reservoir and Natural Fracture Characteristics. The lower two benches of the overpressured Cretaceous Second Frontier Fm. are the target reservoir in this tight gas play. The lower benches are dominantly massive to hummocky cross-stratified nearshore marine sandstone. Porosity averages around 10% with matrix permeability around 25 μd.

Given the low permeability, natural fractures are essential to make this reservoir an economic producer. Prior cores and logs showed that both extensional and shear fractures were evident in wells in and near the Table Rock Field. Based on the examination of the Govt. Union #4 (located in the Table Rock field) core, four types of natural fractures were identified:

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

In contrast, the core from Amoco's Frewen Deep #4 well (located 17 miles east of the Govt. Union #4 well) identified only three types of natural fractures (Lorenz and Billingsley, 1996):

- Extensional natural fractures with large isolated apertures .

- "Irregular anastamosed fracture strands."
- Bitumen-filled splay fractures.

The primary difference is that the natural fractures in the Govt. Union #4 well contain an oblique-reverse sheared fracture (local) overprint on the extensional fracture (regional) component, whereas the natural fractures in Frewen Deep #4 well are dominantly extensional. Since the Govt. Union #4 well currently produces at 6 MMcfd whereas the Frewen Deep #4 was a dry hole, the sheared fracture (local) set appears to provide the essential reservoir connectivity and thus is the controlling factor in enhanced permeability for this formation and area of the basin.

Fault Mapping and Geomechanical Model. Prior to drilling the Rock Island horizontal well, a geomechanical analysis was performed for the area to ascertain whether the location of the well was appropriate for a fault-related natural fracture play. If the area was found to be appropriate then the geomechanical model would be used to determine how to optimally orient the horizontal well. This analysis included a regional fault mapping of the area using existing 3D seismic data. The analysis objectives were to:

1. Examine history of deformation associated with the regional and local fault systems
2. Provide accurate fault geometry in spatial coordinates for use in the geomechanical model.

Selected portions of the Table Rock and Continental Divide Phase II 3D surveys were post-stack depth converted for local fault mapping and for seismic coherency analysis.

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 N30°E and an oblique reverse-strike-slip fault that trends approximately N60°E (**Figure 2-5**). This 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. For the regional analysis (12 townships), only the connected geometry of the thrust and strike-slip faults were used in the

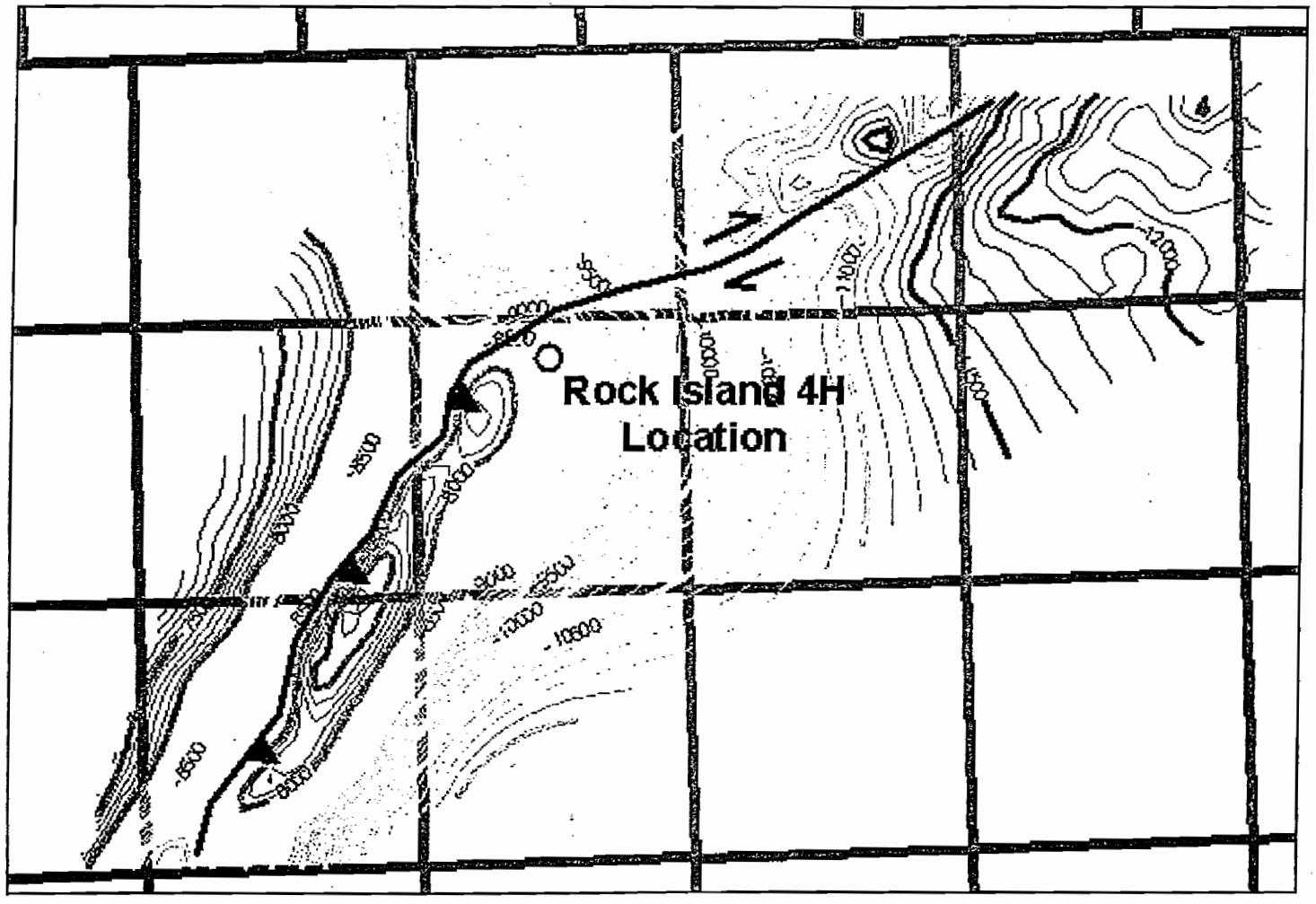


Figure 2-5. The Geometry of the Table Rock Thrust and Strike-Slip Fault System.

geomechanical model and the northern continuation of the thrust was ignored.

The location of shear fractures that were calculated by the geomechanical model is consistent with successful production from the Frontier Fm. (**Figure 2-6**).This does not mean, however, that the region of mapped natural fractures is a single, connected reservoir. Inside the area of local fracture clusters, the Govt. Union #4 produces 6 MMcfd and the Table Rock #104 IP'd at 4.3 MMcfd. Outside the area, the initial tests of Table Rock Units #22 and #43 were discouraging and the wells are shut-in at the Frontier interval. The Rock Island 4H location is at the northeastern extent of the stress and local natural fracture cluster concentration. The model predicts that the well will encounter shear fracture orientations at N27°W and N87°W.

The geomechanical model was then run for the local (80 section) area analysis, appropriate for prospect delineation around Rock Island 4H well location. The analysis was as follows:

1. Depth-migrate the entire 3-D seismic data volume for better definition of structure.
2. Map all small faults using coherency filter to enhance identification.
3. Rerun geomechanical model to capture small perturbations and identify local areas of shear fracture occurrence that may impact offset well location(s).

A full 3D data set was extracted around the horizontal drilling location to map the local fault geometry. The data was again depth-converted to map faults in space rather than time and coherency processing was applied to optimize fault identification. Subtle faults and complex geometry of the main thrust and strike-slip system are revealed after coherency filtering (**Figure 2-7**).

The mapping of the detailed geometry of fault systems at Table Rock permitted the prediction of local natural fracture development at a scale more appropriate for prospect delineation. The geomechanical model was run again with all the smaller faults included. The results showed that the Rock Island 4H occupies an area between two small faults and appears to have hit a zone of enhanced stress concentration (**Figure 2-8**).

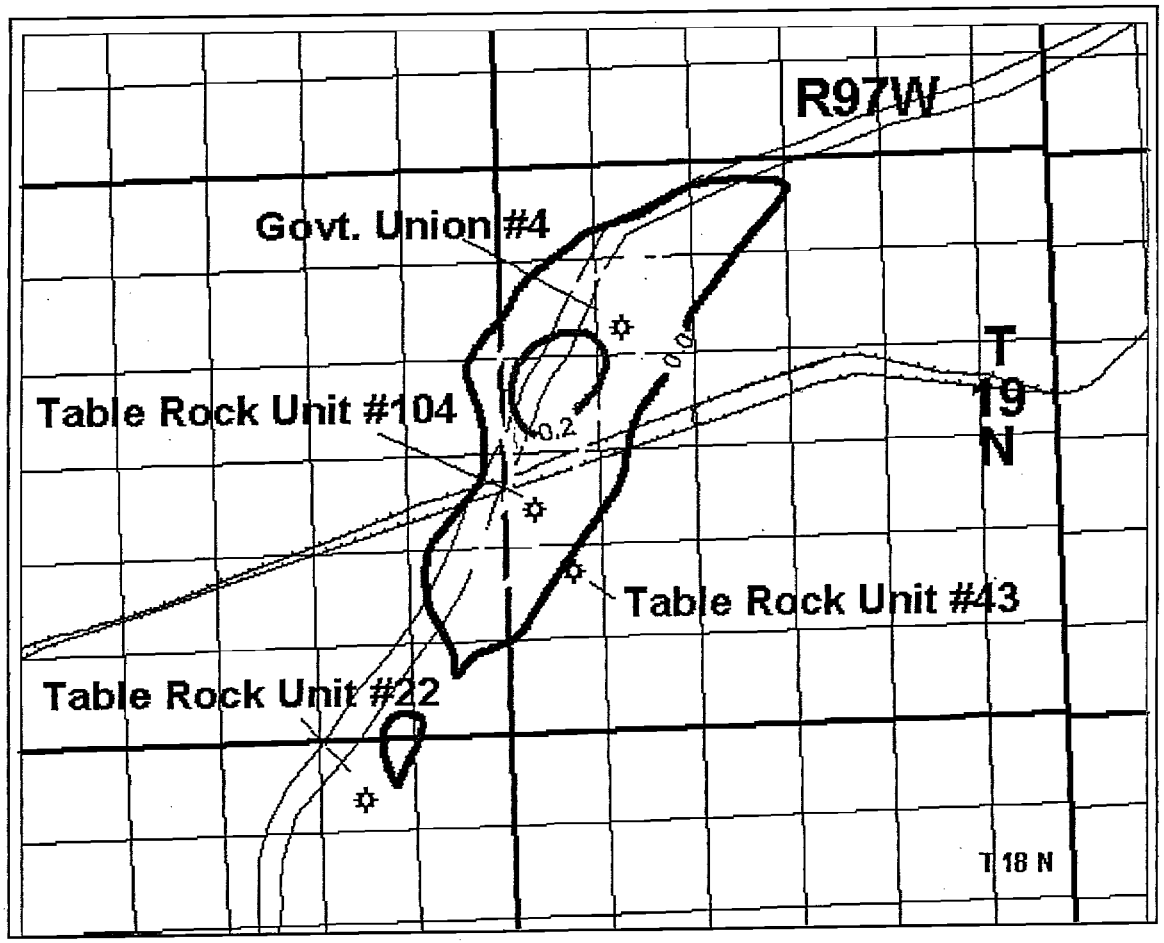


Figure 2-6. Sheared Fracture Occurrence as Calculated by the Geomechanical Model Based on the Regional Geometry of the Thrust-Strikeslip Fault System.

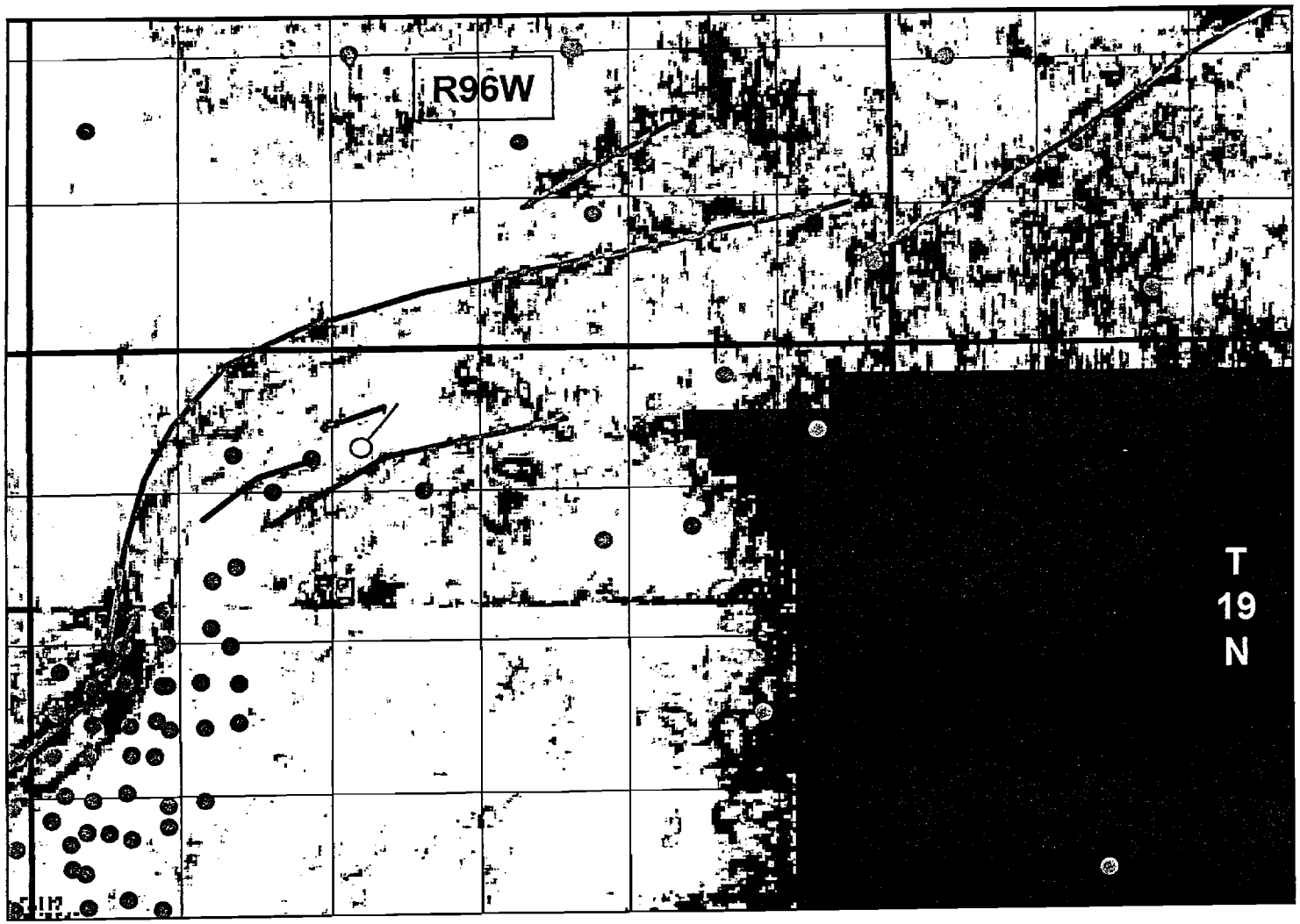


Figure 2-7. Coherency Depth-Slice at 16,000 feet. Red Lines are Mapped Faults. Yellow Dot is Location of Rock Island 4H.

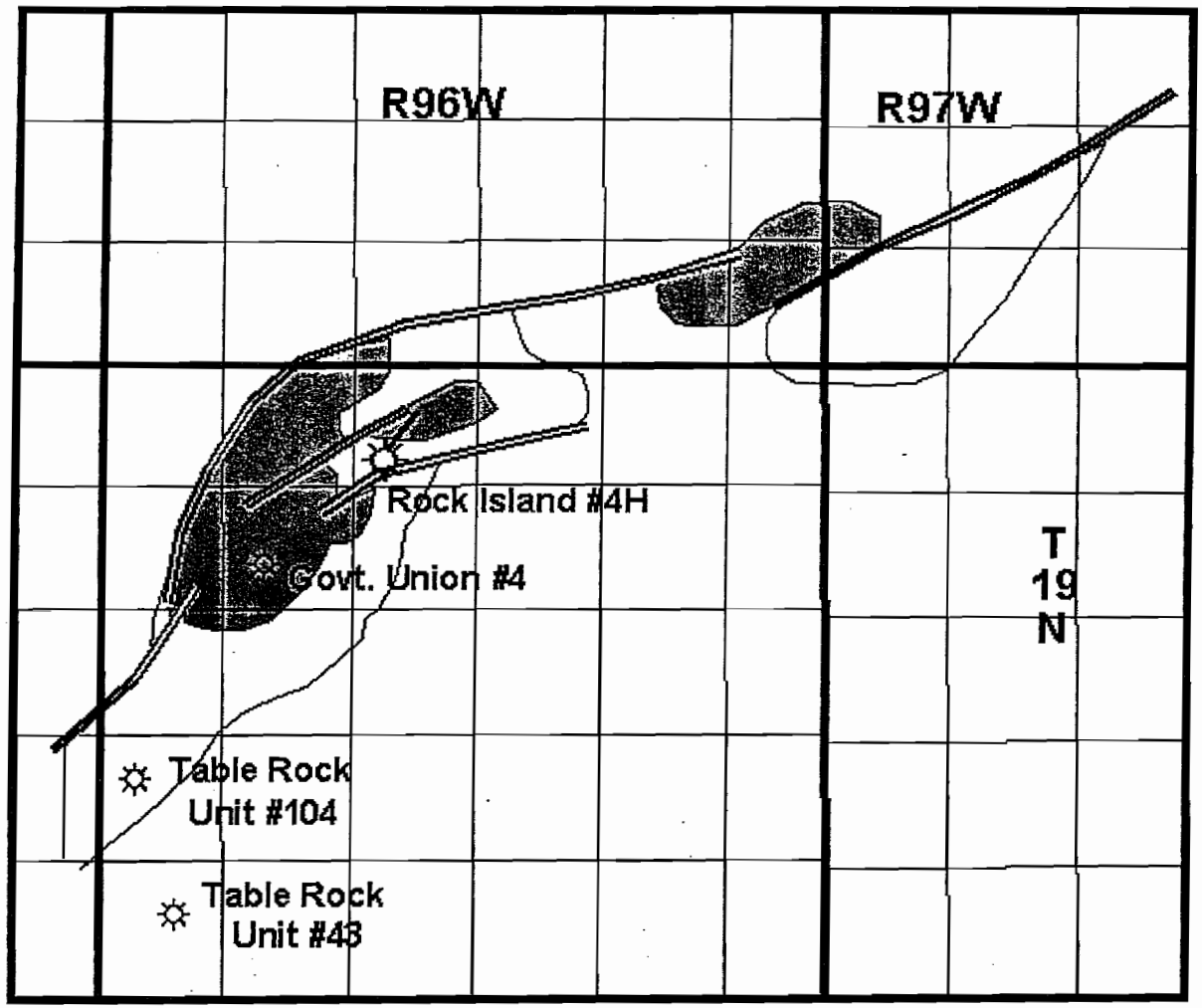


Figure 2-8. Stress Concentrations and Expected Fault-Related Natural Fracture Development as Calculated by the Geomechnical Model in the Vicinity of the Rock Island 4H.

Conclusions and Discussion

The geomechanical approach provides one means to map fault-related local natural fracture clusters that control a reservoir's highly productive "sweet-spots." The approach is scientifically rigorous and utilizes standard seismic data and borehole information. The integration of 3D seismic with quantitative modeling offers the industry a new set of technologies for detecting and predicting the location of natural fractures before drilling. The delineation of tight gas prospects using these technologies provides a significant cost advantage over a statistical or step-out drilling approach and allows for a more successful exploration and development program in naturally fractured reservoirs.

The geomechanical approach can be used "stand-alone" or in conjunction with other natural fracture detection techniques, such as:

- Corroboration of seismic anomalies from azimuthal P-wave methods
- Extension of regions of natural fractures detected by 2D shear methods.

Further development and testing of the geomechanical model in other basins and more complex fault and fracture settings is needed to fully demonstrate the value and reliability of this promising approach.

Appendix E presents the summary and results of geomechanical analysis of the Table Rock Horizontal Drilling Project.

Entire Chapter

CHAPTER 3
Green River Basin Partitioning Study

Introduction

The final phase of the Project has focused on the Greater Green River Basin where substantial tight gas reserves are known to be present in the overpressured portions of the basin. Previous investigators of the Greater Green River Basin's natural gas resources that have estimated Upper Cretaceous Mesaverde and Frontier Fm tight gas sands hold over 3,550 Tcf (Law, 1989). Considerable differences exist in estimates of remaining recoverable reserves for these two formations, ranging from 22 Tcf (Scotia Group, 1993) to 77 Tcf (USGS, 1995).

The Greater Green River Basin is located in southwestern Wyoming and northeastern Colorado (**Figure 3-1**). It comprises a number of foreland-style sub-basins including Green River, Hoback, Red Desert, Washakie and Sand Wash (**Figure 3-2**). The basin is structurally defined by a number of thrusted terranes that surround the basin, as well as internal arches such as the Rock Springs uplift.

The scope of Advanced Resources' effort has been the overpressured, basin center Mesaverde Group and Frontier Formation low permeability natural gas plays (**Figure 3-3**). To effectively explore for this resource Advanced Resources has developed a methodology for high-grading areas of tight gas basins with greater likelihood for the presence of natural fracturing and the economic development of low permeability natural gas resources. Advanced Resources has also advanced the methodology to the prospect generation phase to exploit productive areas of the plays.

This study, which focuses on these two important Upper Cretaceous natural gas plays in the Rocky Mountains, is intended to having at least the following uses:

- Assisting future planning of DOE/FETC's Low Permeability Natural Gas Program.
- Providing information to basin operators for more efficiently developing these resources.
- Measuring the impacts of E&P technology advances from R&D.
- Providing information on volumes and costs of future natural gas supplies.

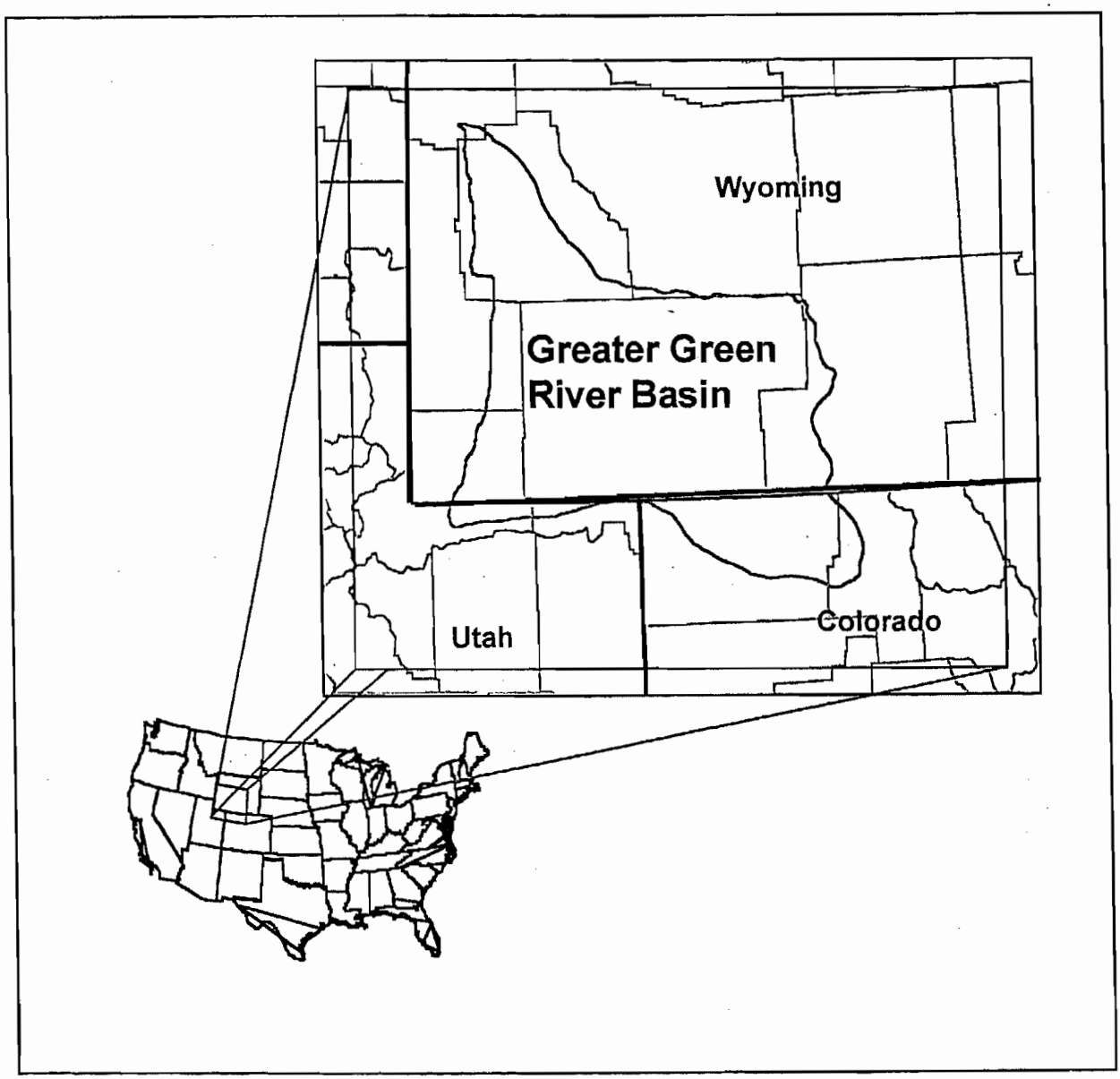


Figure 3-1. Greater Green River Basin

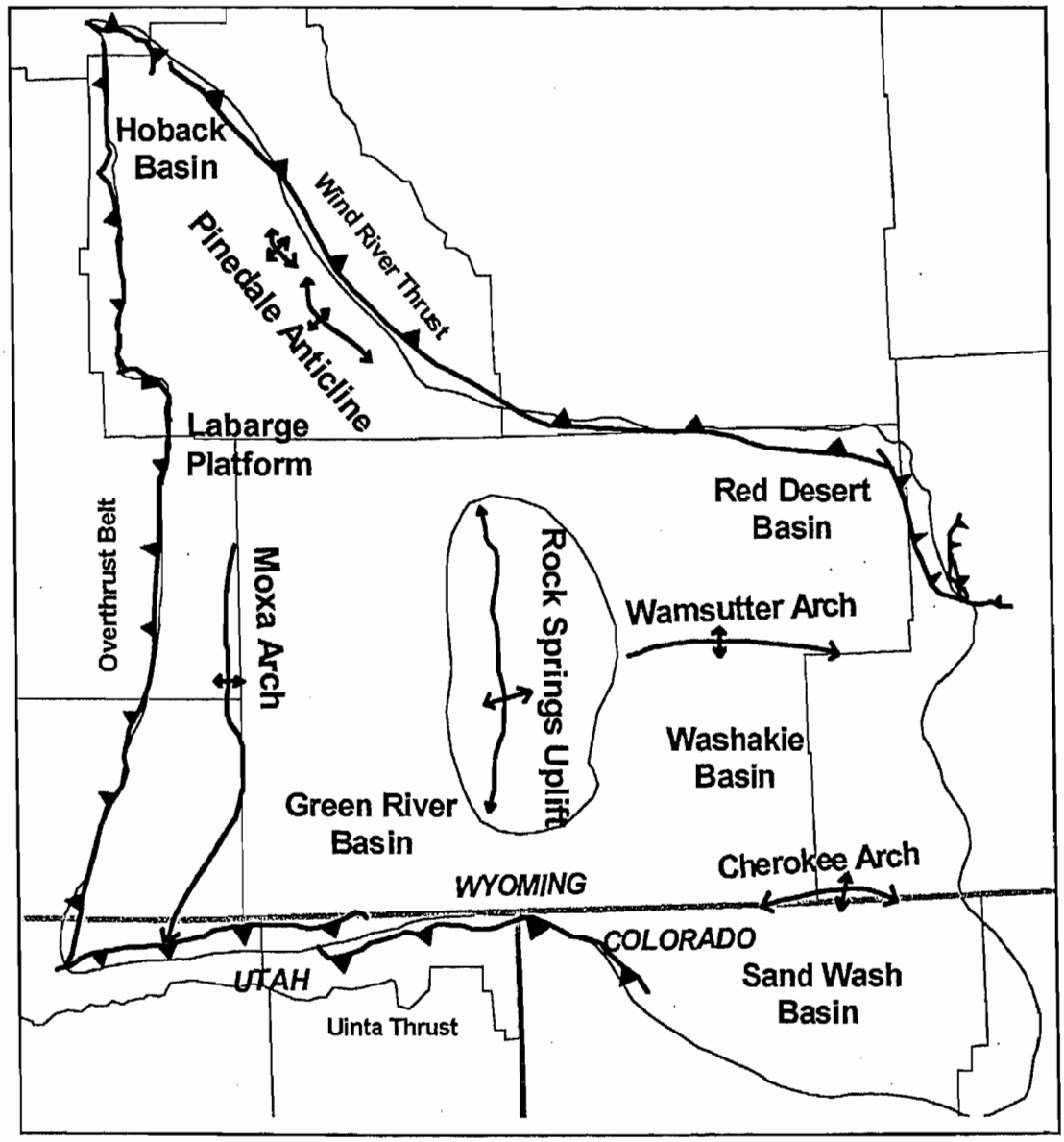


Figure 3-2. Major Structural Elements of the Greater Green River Basin

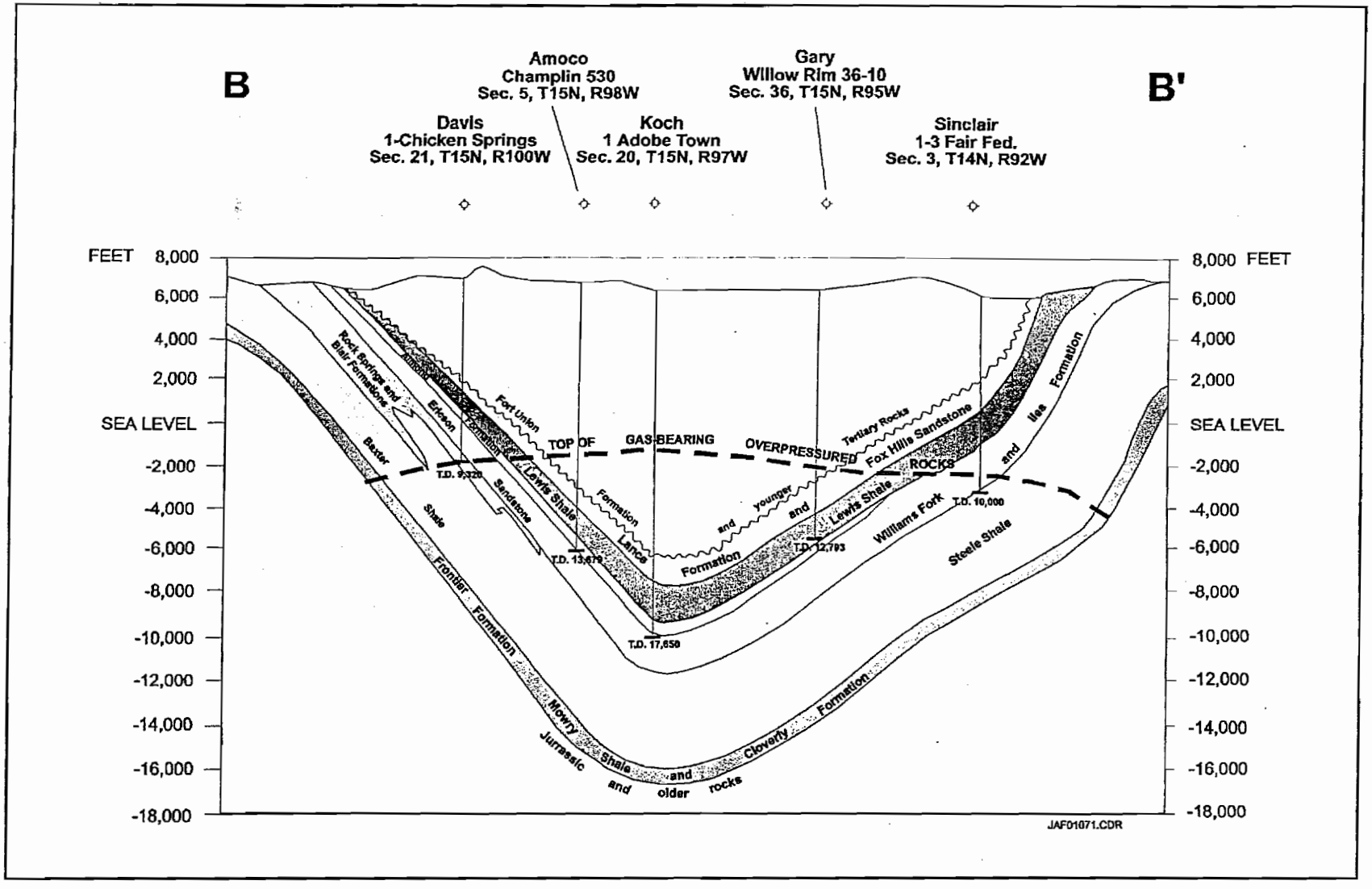


Figure 3-3. Cross Section B-B'

Methodology

Economic exploration and development of the low-permeability Mesaverde and Frontier formation natural gas plays, requires the delineation of areas that have a greater likelihood for exhibiting natural fractures. As the first step, Advanced Resources partitioned the basin into regions with similar geologic, structural and resource characteristics as an aid to further analysis. Next, we categorized each partition, using remote sensing and potential field geophysical data for structural complexity -- basement faulting and surface lineaments associated with natural fracturing. Next, we assembled log and reservoir data to estimate gas in-place and further categorize each partition using resource-in-place. Finally, we used break-even economic analysis to further delineate the partitions.

To move beyond the basin partitioning to assessing individual prospects, we utilize 3-D seismic, stress modeling and geomechanical modeling to characterize drillable locations that show greater likelihood for exhibiting natural fracturing. The previous discussions of the Rulison, Mamm Creek and Rulison case studies illustrates our prospect development approach.

Partitioning. For analytic purposes, the Greater Green River Basin was divided into 20 partitions (**Figure 3-4**) based on structural features within the basin, reservoir characteristics and other geologic information, as described below. Examination of the partitions was initiated with the Greater Green River Deep partition, site of the Stratos-1 well (see ***Appendix C*** for discussion of the Stratos well). Four of the partitions are areas of conventional, established production; the balance of 16 partitions is the site of overpressured, basin-centered gas. Individual descriptions of the partitions are described in ***Appendix D***. The partitioning methodology is described below.

Structural Elements. Natural fractures and permeability are the most essential components to gas recovery from the tight Upper Cretaceous gas sands. As a result, our first partitioning criterion was structural features -- uplifts, arches, folds, basement features and normal, reverse and strike-ship faults -- and their association with natural fracture development. Structure maps, previously identified basin structural features, satellite imagery (**Figure 3-5**), gravity and magnetic surveys (**Figures 3-6 & 3-7**), and selected seismic lines provided the basic data.

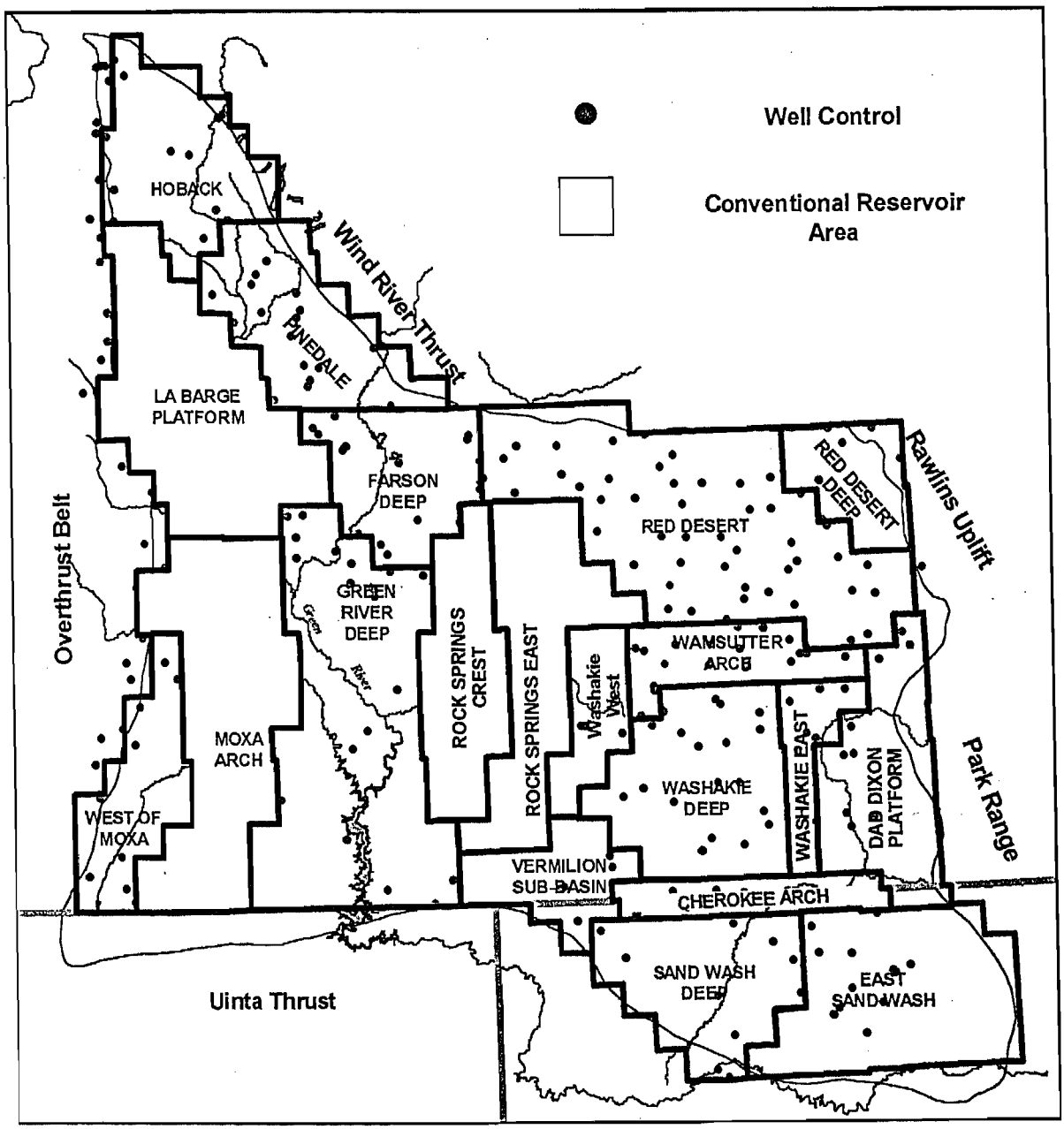


Figure 3-4. Basin Partitions

A seven scene Landsat-TM satellite image mosaic was constructed for surface linear features analysis.

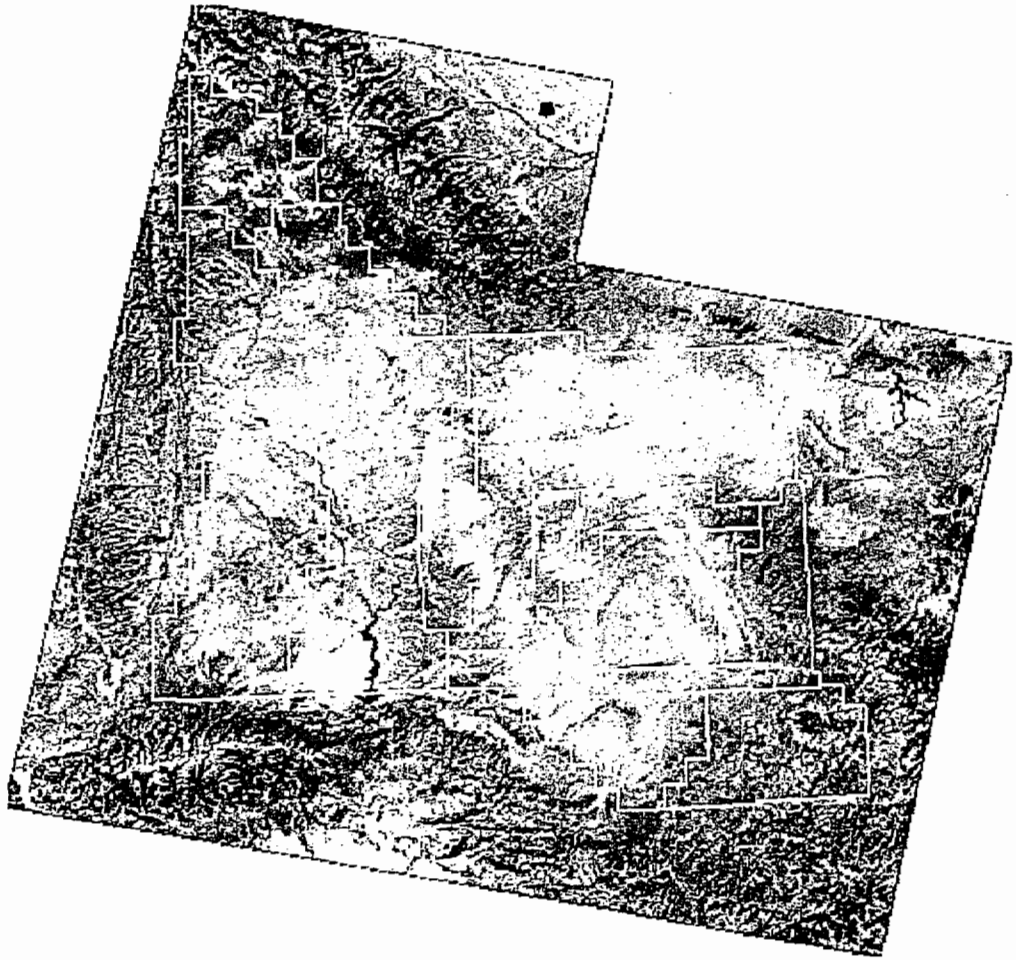


Figure 3-5. Regional Surface Features: Landsat Image Analysis

Gravity data reveal the architecture of the Greater Green River Basin and facilitate basin partitioning.

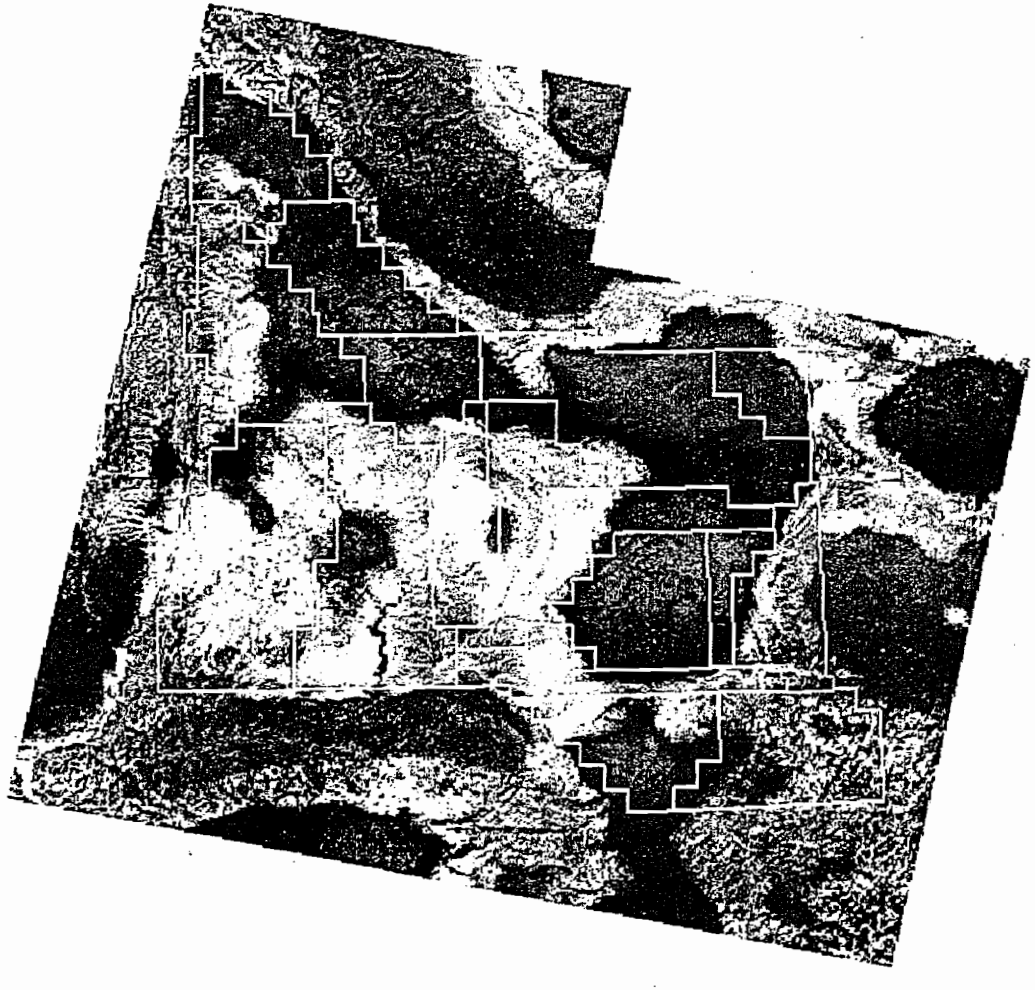


Figure 3-6. Regional Basement Anomalies: Isostatic Gravity

Aeromagnetic data reveal significant basement-related structures. Pinedale/ Hoback sub-basin contains several north- and northwest-trending basement anomalies.

Figure 3-7. Regional Basement Anomalies: Aeromagnetic Data

Depth. Well depth has a direct relationship with well costs and has been judged to be correlated with loss of primary porosity and permeability. We used the 7,500 foot and 15,000 foot depth contours to partition the effects of depth on the geologic and economic potential of gas development. **Figure 3-8** shows depth contours for the Frontier Formation. **Figure 3-9** shows depth to the Mesaverde Group.

In the Greater Green River Basin, average drill depth to the Frontier Formation in the basin is significant, averaging about 14,700 feet. The shallower Mesaverde averages about 10,800 feet of depth.

Overpressuring. Overpressured areas were assessed to define the areal extent of the plays. Overpressured settings have a strong relationship with gas center basins and often help define the boundary between the fully gas charged and the transition (gas and water) zone. Pressure boundaries were established by using early work by Law (1989), from field studies prepared by Advanced Resources, and selected control points assembled from public data. These ancillary data include vitrinite reflectance, mud weights, pressure test data from wells and mapping of the occurrance and nature of formation water (Barlow & Haun, 1999).

Figure 3-10 displays overpressuring within the Frontier Formation; **Figure 3-11** shows areas of overpressuring in the Mesaverde group. The upper part of the Mesaverde Group, the Upper Almond Formation, was excluded from this study because it is a maturely developed primarily conventional gas formation.

The Frontier Formation is largely overpressured occur the basin, except in areas of conventional production (Figure 3-10). Overpressured Mesaverde Group sediments are restricted to areas north and east of the Moxa Arch/LaBarge Platform and to the eastern portion of the basin (Figure 3-11). Due to the presence of conventional production or due to a lack of overpressuring, the LaBarge, Moxa Arch, Rock Springs Crest and Rock Springs East partitions were not analyzed further in the study.

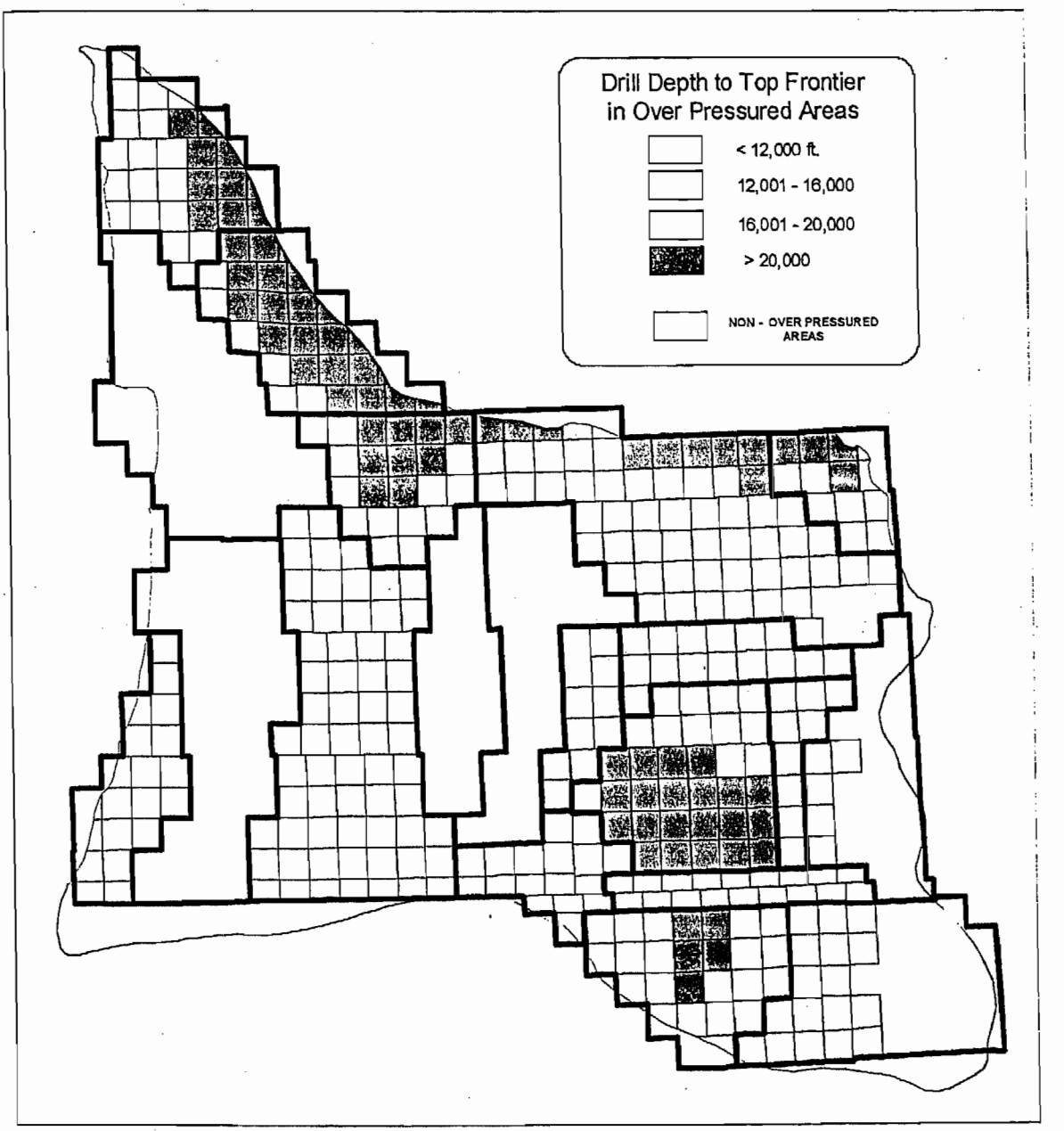


Figure 3-8. Frontier Drill Depth

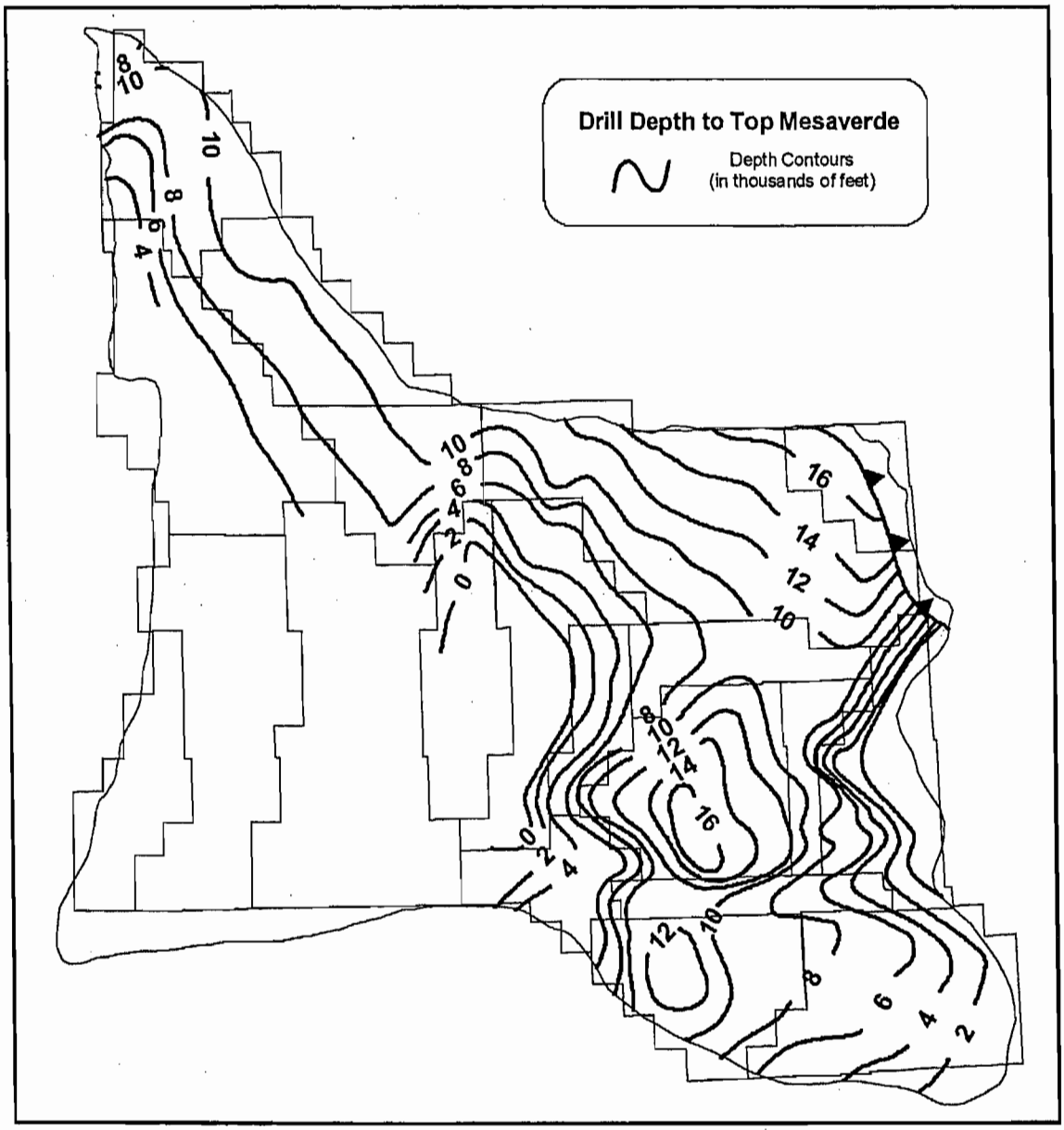


Figure 3-9. Mesaverde Drill Depth

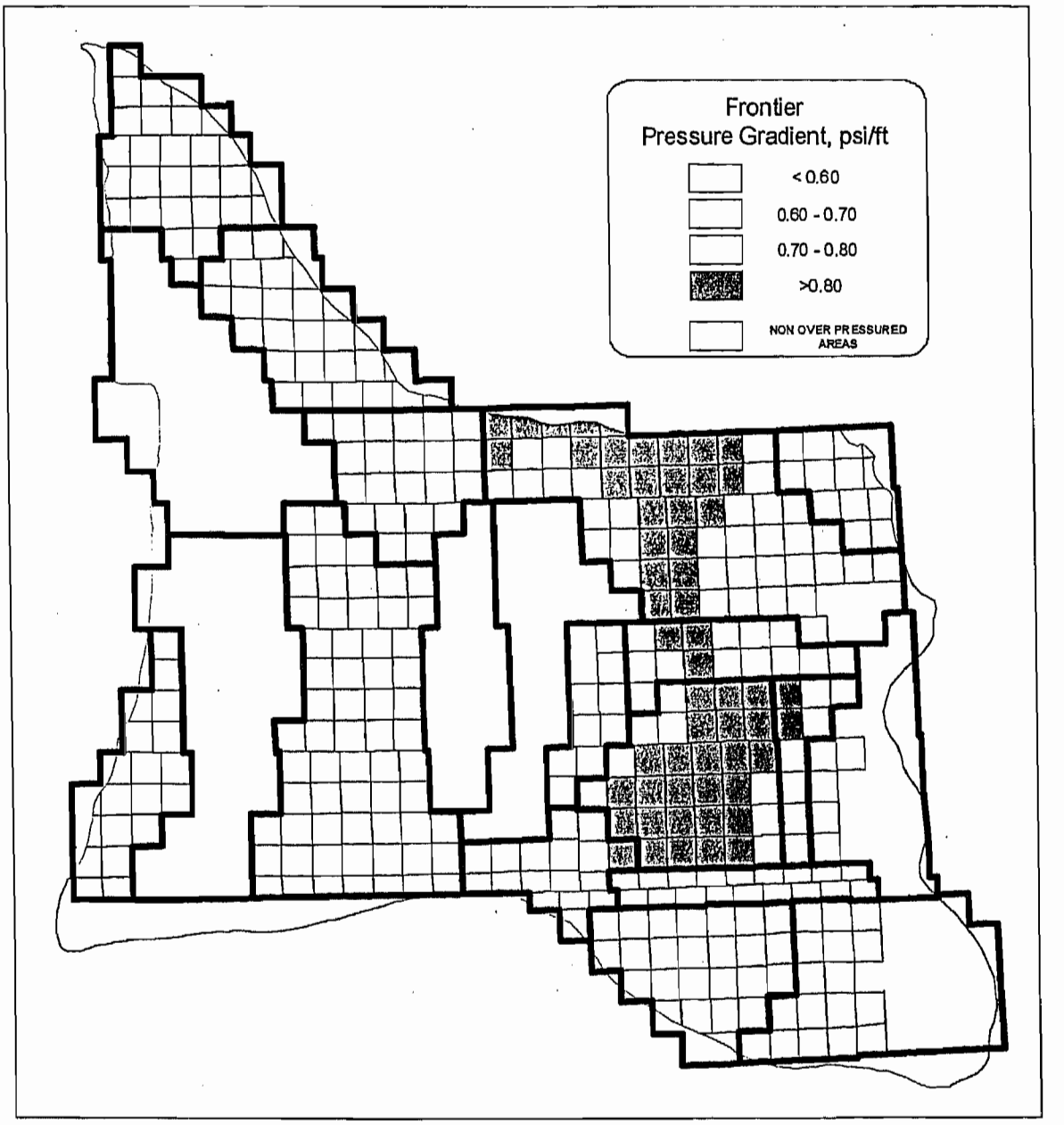


Figure 3-10. Frontier Overpressured Areas

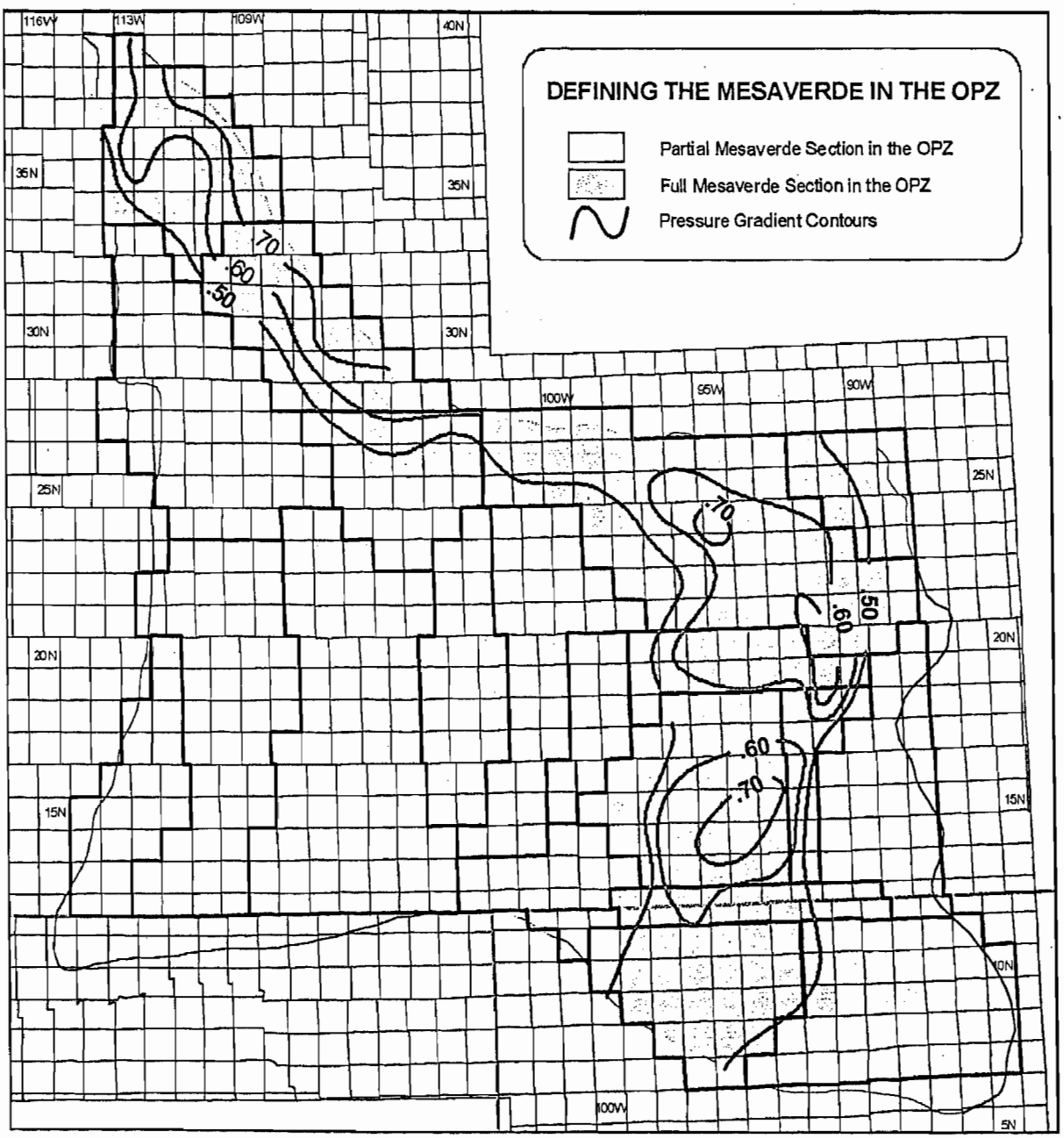


Figure 3-11. Mesaverde Overpressured Areas

Geology and Deposition. Sandstones of the Frontier Fm were deposited in a fluvial deltaic to nearshore marine environment. Fluvial reservoirs dominate only in the westernmost quarter of the Greater Green River Basin. Frontier sandstones generally have 100 to 150 feet of gross thickness, thinning to the south and east. The Frontier Formation is a stratigraphically complex exploration target with multiple stacked reservoirs, reflecting changes in eustatic sea level, variability in sediment supply, and a high degree of tectonism.

In this study, examination of the Mesaverde Group was restricted to its lower portion comprising Main Almond, Rock Springs, Blair, Haystack Mountains, Allen Ridge and Illes formations. The Mesaverde Group is significantly thicker than the Frontier Formation reaching nearly 5000 feet of gross thickness in the eastern and central parts of the basin. The lower part of the Mesaverde Group was deposited during a major eastward transgression of the interior Cretaceous seaway, and is composed of sediments deposited in alluvial plain, flood plain, coastal plain, tidal flat, delta plain, marine shoreline and marine shelf and slope environments. Marine influence is greater in the eastern portion of the basin.

Maturity of Development. Overall the Frontier Formation is an immature gas play; exceptions are the Moxa Arch on the southwest edge of the basin; the La Barge Platform on the western edge of the basin; and, the Rock Springs Crest, in the center of the basin. Scattered Frontier Fm. development also exists on the Rock Springs East and the Dad Dixon Platform. The overpressured lower Mesaverde Group is largely undeveloped, except along the Wamsutter Arch.

Resource Estimates

We next assessed the natural gas resources in-place in the Frontier and Mesaverde tight gas plays. The objective was to highlight portions of each partition and play that could be targeted for further evaluation and testing by industry. For each partition, a gas resource-in-place was calculated on the basis of area, net sand thickness, porosity, water saturation, temperature (as a function of depth) and pressure (as a function of depth).

To accurately assess the resource base present in the Greater Green River Basin, we used a primary database derived from well control, based on the selection of the deepest, complete well in a given township to represent many of the parameters for that township. Well logs were collected from the Denver Earth Resource Library (DERL) and analyzed to provide the parameters necessary to calculate gas-in-place. Well data were supplemented by published data.

To determine wells to be analyzed, a list of "high-graded" wells was developed, using Advanced Resources' GIS database to streamline and accelerate the data gathering process. The multi-step filter selected the two deepest wells in each township that were completed after 1975 and that penetrated either the Mesaverde or the Frontier formation. The year 1975 was used as a filtering parameter because of the advances that have taken place in logging technology since that time.

On the western side of the basin, where correlations can be difficult due to the dominance of nonmarine sands, wells from published cross sections (e.g. Rholer, 1990) were used to guide determination of formation tops. This was supplemented using PI/Dwights Scout Tickets. Other wells were selected based on their age, depth, and the formations they penetrated.

Gross sand in the wells was calculated generally using a gamma ray cut-off of 60 API units. Net sands were determined based on counts from neutron density logs. The net sand porosity cutoff varied with depth. **Table 3-1** shows the porosity cutoffs that were used to define net pay in the Mesaverde and Frontier Formations. Net sand and porosity maps for the Frontier Formation (**Figure 3-12** and **Figure 3-13**) and Mesaverde Group (**Figures 3-14 and 3-15**), respectively, were used.

Mud weights, drill stem tests, and bottom hole temperatures were recorded from the log headers and used in calculations to define the top of the overpressuring. Neutron-density cross-over (NDXO) was also used to help estimate the top of overpressuring. Water saturation in the basin was assumed to be 40 percent.

Total resource-in-place was determined to be about 216 Tcf for the overpressured Frontier play (**Figure 3-16**) and 1015 Tcf for the overpressured Mesaverde Group (**Figure 3-17**).

Table 3-1

Porosity Cutoffs Used to Define Net Pay
Mesaverde and Frontier Formations

Depth Upper (ft.)	Bound Lower (ft.)	Porosity (%)
0	2,500	12
2,500	5,000	10
5,000	7,500	8
7,500	10,000	7
10,000	15,000	6
15,000	20,000	5
20,000	25,000	4

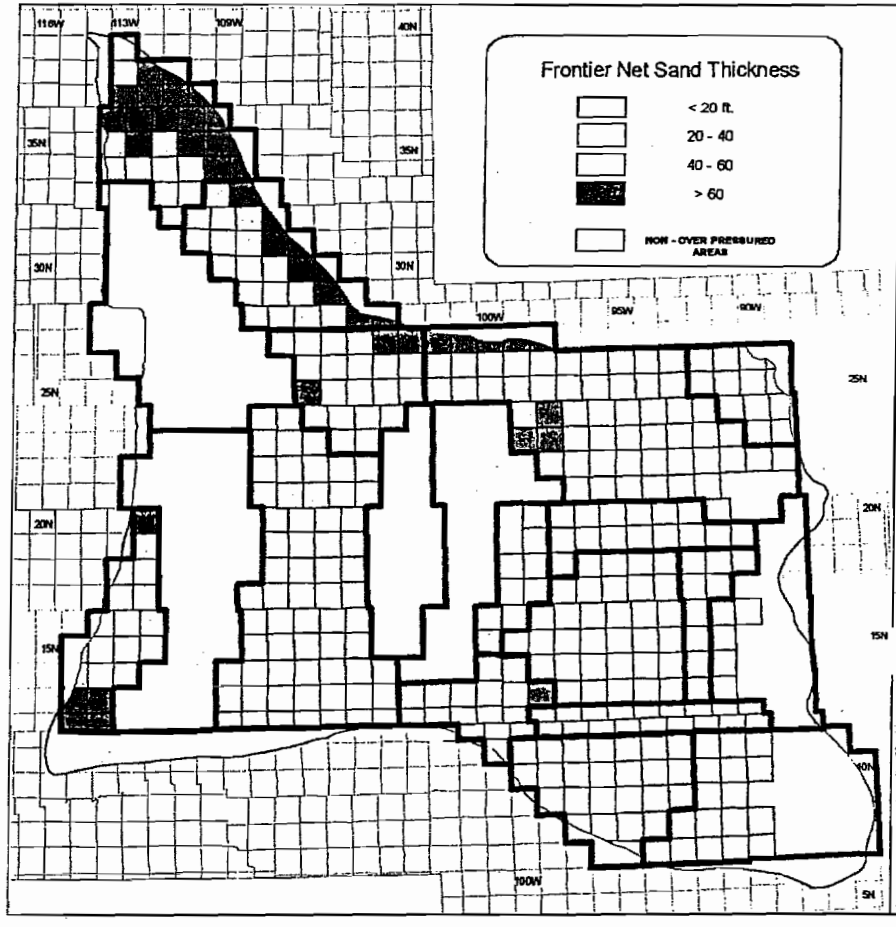


Figure 3-12

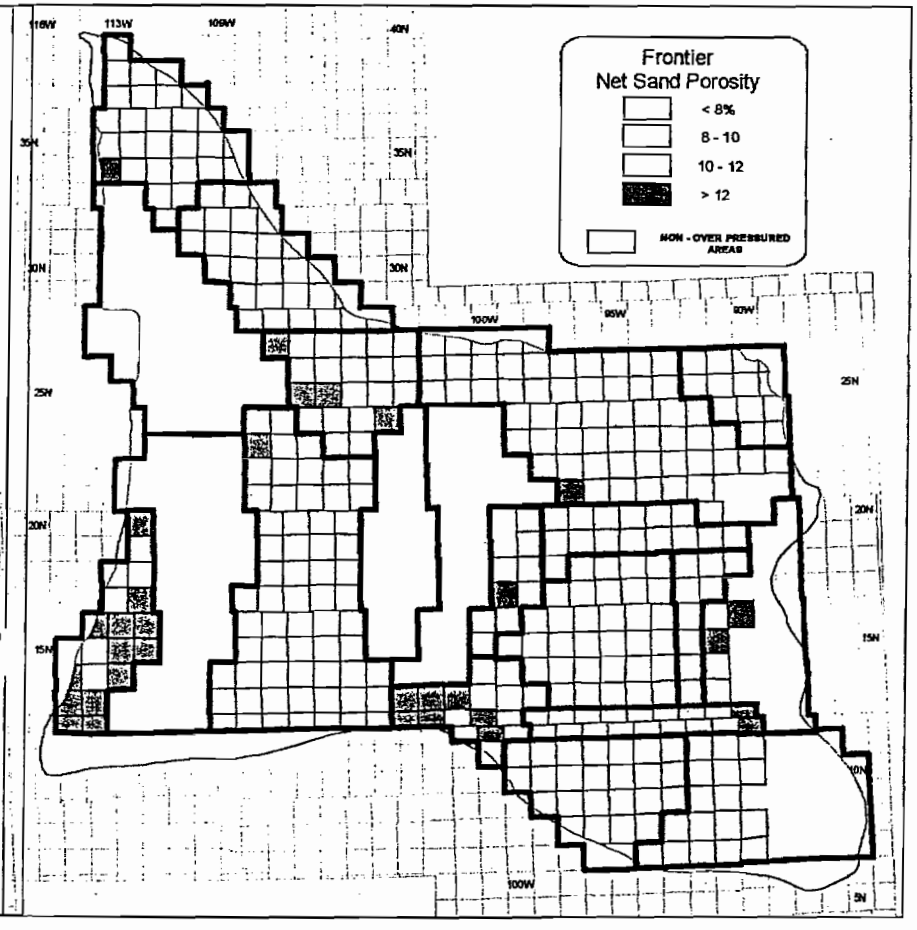


Figure 3-13

Frontier Formation: Net Sand and Porosity.

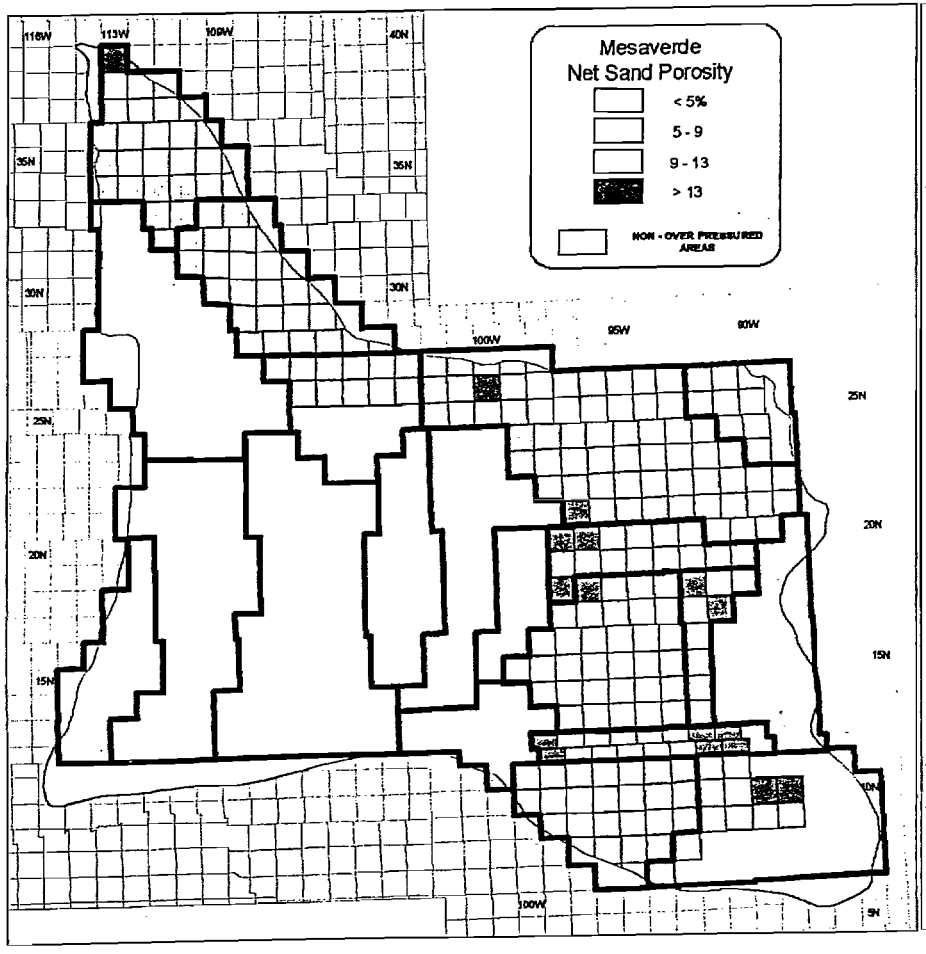


Figure 3-14

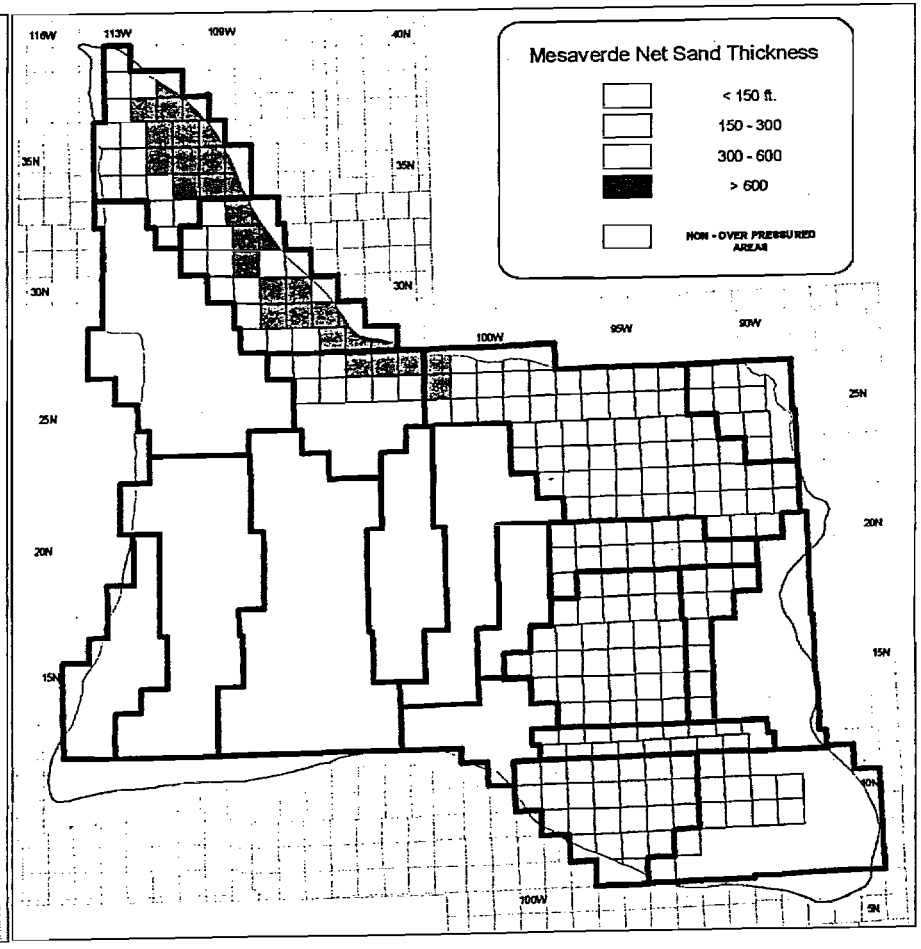


Figure 3-15

Mesaverde Formation: Net Sand and Porosity.

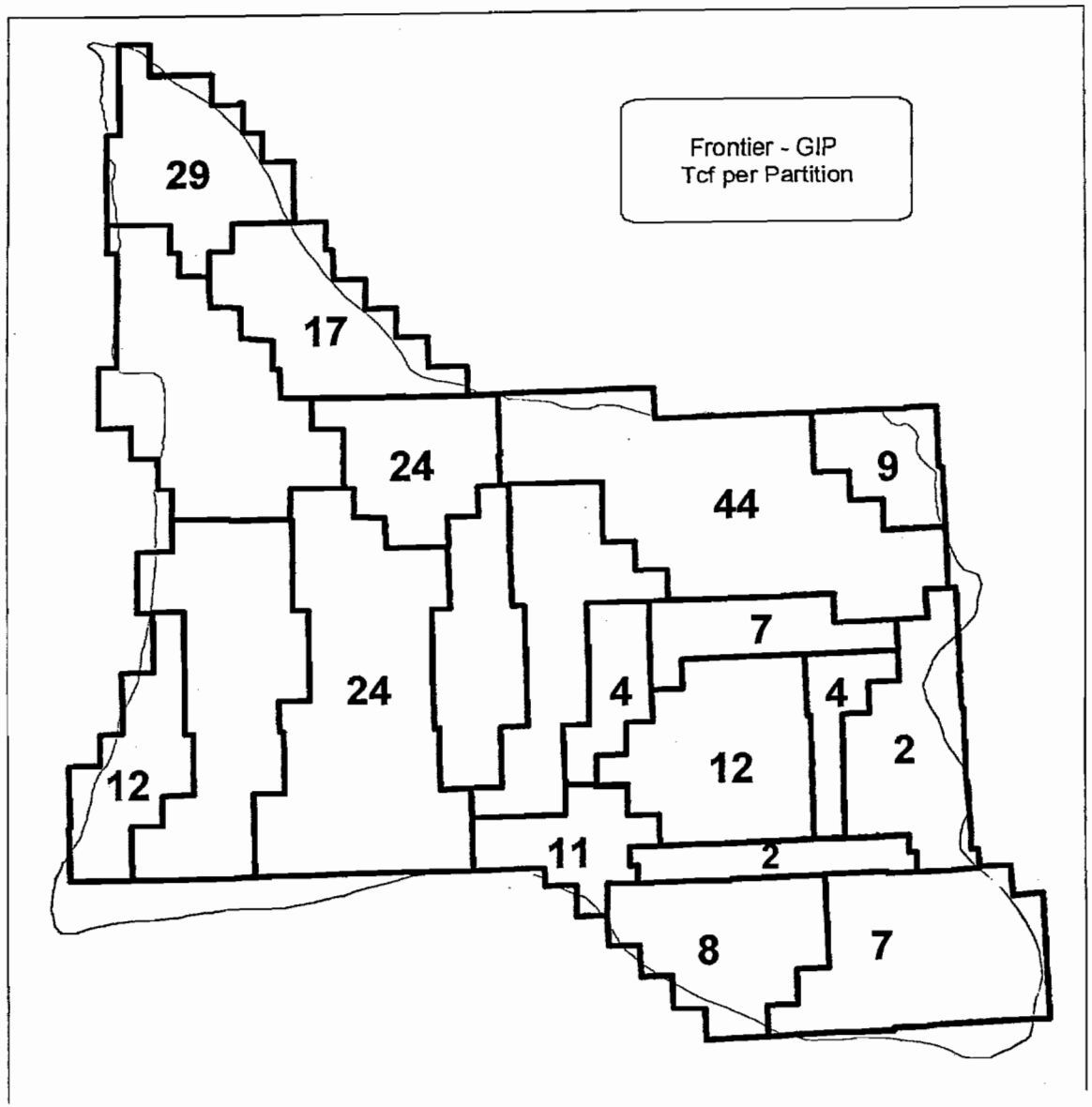


Figure 3-16. Basin Partitions.

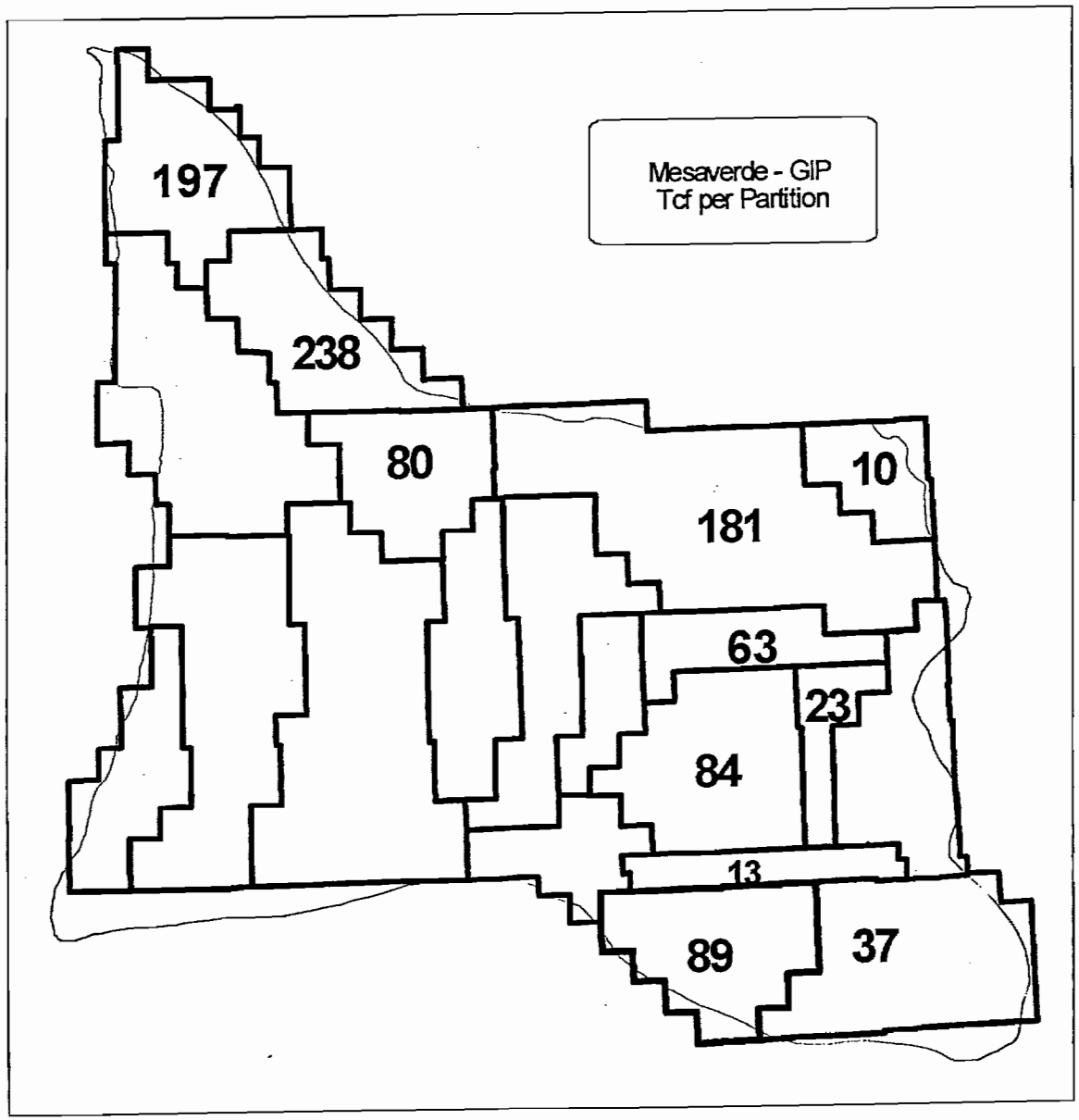


Figure 3-17. Basin Partitions.

Recoverable Resource. To determine those partitions in the basin that would be most prospective, Advanced Resources developed a simple break-even economic model for the Frontier and Mesaverde plays. Based upon the natural fracture ranking and the development of production profiles, Base and Advanced cases were developed.

Existing gas production data were used to construct distributions of expected well performance for the Base and Advanced cases. For the Frontier Formation (**Figure 3-18**), horizontal wells were used in the Advanced case where recovery was assumed to be three times current production rates. For the Mesaverde, well performance was assumed to improve by 20 percent in the advanced case compared to the base case (**Figure 3-19**). Due to the greater thickness of the Mesaverde, vertical wells were assumed to be used in the development of the play.

The distribution of expected well performance was adjusted within the partitions to reflect differences in storage capacity (gas-in-place). Drilling costs were established as a function of depth based on recent API/JAS data. Completion and facilities costs were estimated based on Advanced Resources' industrial experience.

While the Base case assumed the use of vertical wells for both plays and statistical drilling, the Advanced case implemented a number of improvements:

- An ability to efficiently determine high-quality areas within the partitions based upon the presence of natural fracturing (**Table 3-2**)
- Ten percent improvement in drilling success rates
- Improved well performance in each of the plays
- Reduction in D&C and O&M costs by 15 percent

Results. Results of the modeling show that large amounts of natural gas-in-place, through the integrated application of advanced E&P technology are technically recoverable. In the Advanced case, about 41 Tcf of gas are technically recoverable from the Frontier Formation and over 123 Tcf are recoverable from the Mesaverde. Further, the Advanced case represents a substantial improvement in recovery compared to the Base case (**Table 3-3**). With regard to economically

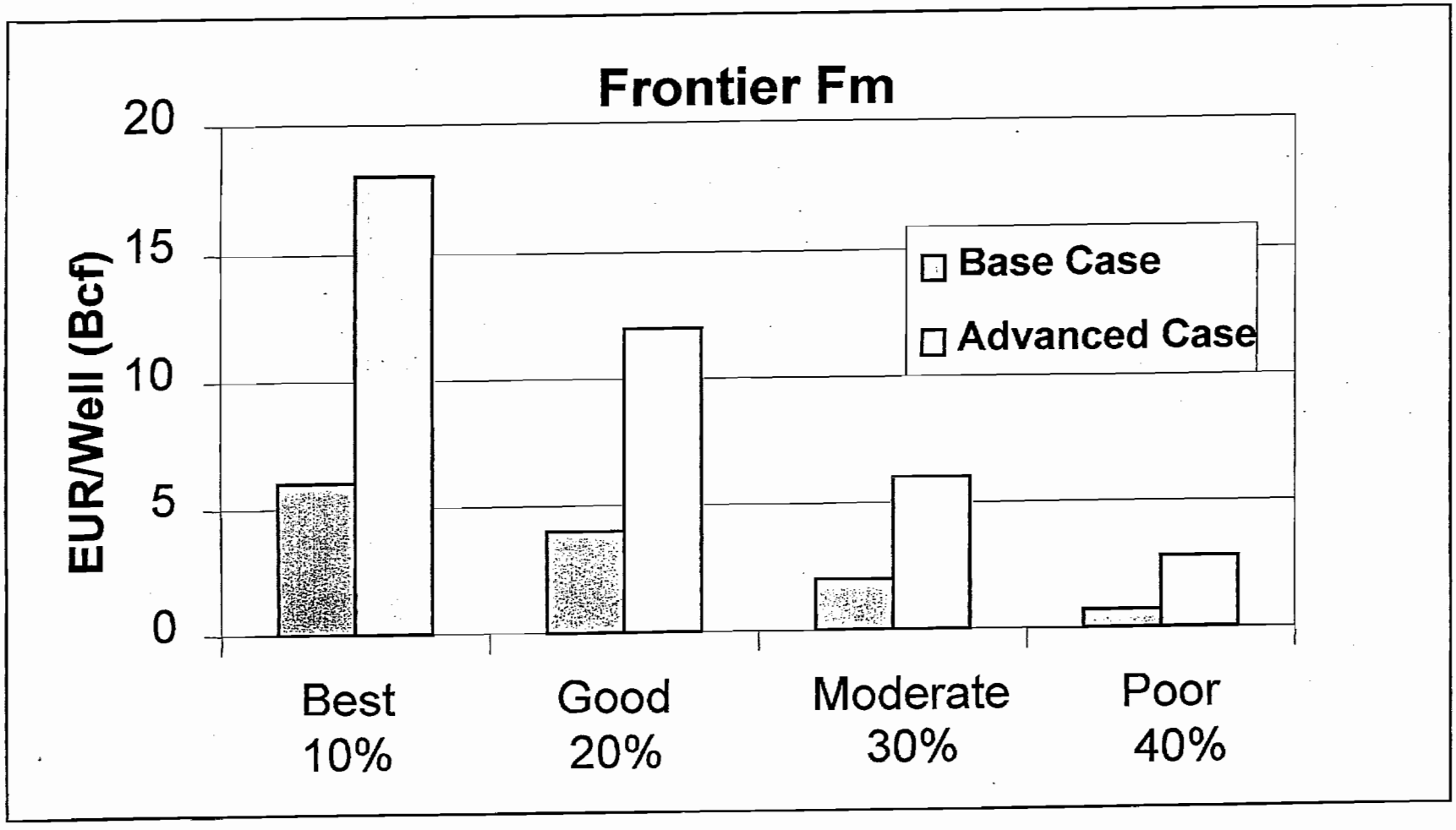


Figure 3-18. Distribution of Well Performance

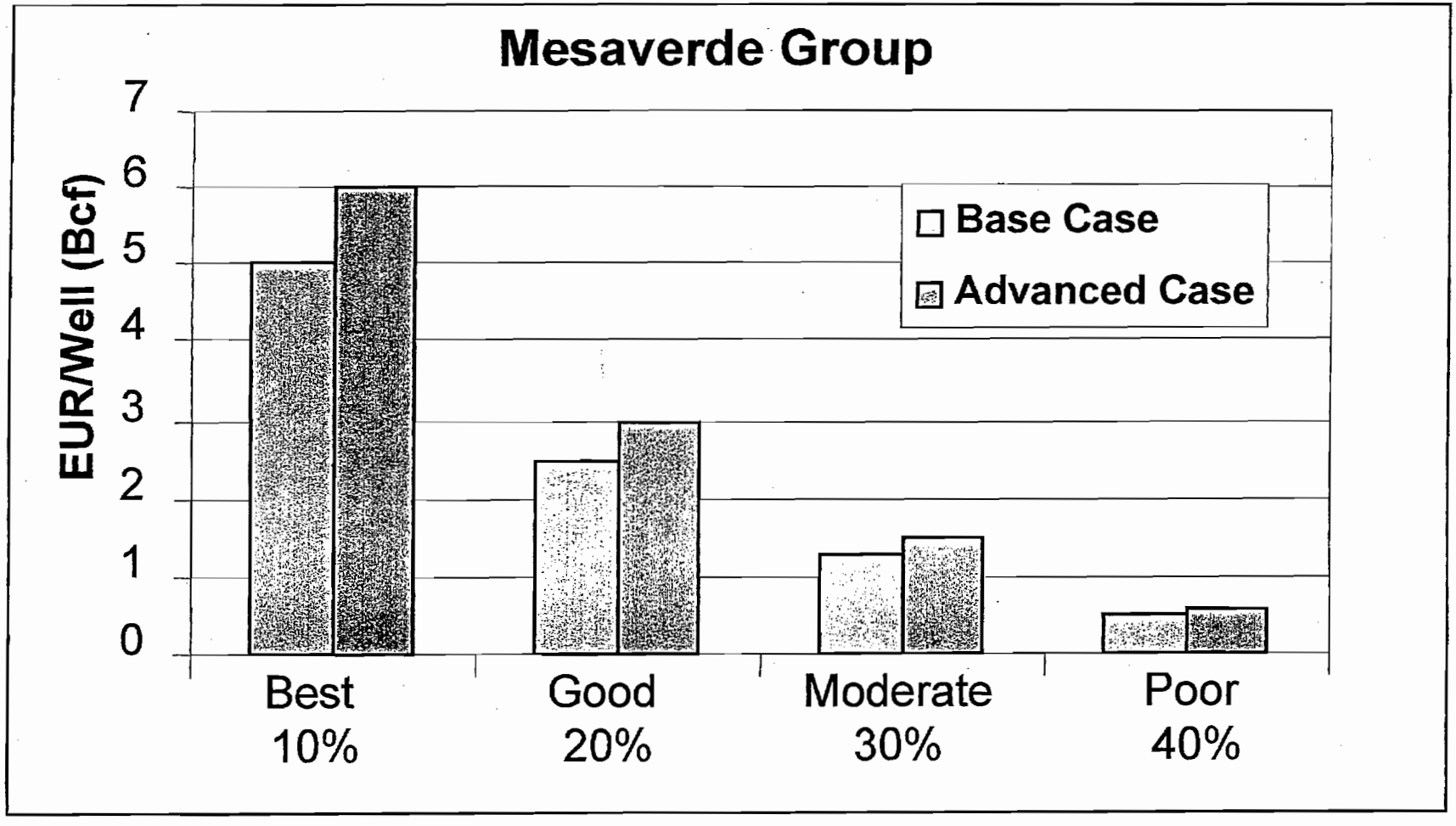


Figure 3-19. Distribution of Well Performance

Table 3-2

Natural Fracture Ranking and Distribution

Partition	Ranking (Number of Townships)			
	Best	Good	Moderate	Poor
Green River Deep	5	15	23	20
Pinedale	4	7	10	7
Hoback	2	4	4	18
Farson Deep	2	2	8	10
East Sand Wash	2	2	7	6
Washakie West	2	2	1	4
Cherokee Arch	2	1	3	3
Sand Wash Deep	1	10	10	3
Washakie Deep	1	7	16	9
Wamsutter Arch	1	4	4	5
East Washakie	1	-	5	3
Red Desert	-	14	10	34
Vermilion	-	4	2	8
West of Moxa Arch	-	2	7	11
Red DD	-	2	1	10
Dad Dix	-	1	2	1
TOTALS	23	77	113	152

Table 3-3

Economically Recoverable Natural Gas Resources (Tcf)

	Technically Recoverable	Moderate Cost (<$3/Mcf)	High Cost (>$3/Mcf)
FRONTIER			
• Base Case	23	4.3	19.1
• Advanced Tech. Case	41	2.4	16.8
MESAVERDE*			
• Base Case	87	38.4	48.7
• Advanced Tech. Case	123	78.9	43.9

recoverable resources (at costs of $3/Mcf or less), in the Advanced case approximately 24 Tcf of gas could be developed with Frontier Formation and 79 Tcf of gas in the Mesaverde Group.

A tally of townships for the recovery of low cost gas and the recoverable resource is shown in **Tables 3-4 and 3-5** (Frontier) and **Tables 3-6 and 3-7** (Mesaverde). These results illustrate the significant improvement associated with the Advanced case. Of the potential technological advances, the reliable identification of naturally fractured areas and the use of horizontal drilling in the Frontier Formation have the highest impact on the economic recovery of resource in the plays. The modeling further indicates that, for the Frontier Formation, the Red Desert, Hoback and Farson Deep partitions are the most attractive partitions for development with and almost 12 Tcf of recoverable gas at less than $3.00/mcf. For the Mesaverde, the higher ranked partitions comprise the Pinedale, Sand Wash Deep, Hoback, Wamsutter Arch, Red Desert, and Farson Deep partitions. These partitions have the potential for over 67 Tcf of recoverable gas at less than $3.00/Mcf.

The Advanced Resources analysis shows that a gas prospects in the Greater Green River Basin can be on the order of 200 to 500 Bcf in size and that numerous such multi-section sized "sweet spot" prospects may exist.

Table 3-4

Frontier Base Case

Partitions	Technically Recoverable Resource (Tcf)	Economically Recoverable Resources			
		<$3 Gas Township Count	Recover. Resource (Tcf)	<$3 Gas Township Count	Recover. Resource (Tcf)
Hoback	2.4	3	1.1	25	1.3
Farson Deep	2.6	1	0.9	21	1.7
Vermilion	1.0	3	0.6	11	0.4
Washakie West	0.8	2	0.5	7	0.3
West of Moxa Arch	0.9	1	0.4	19	0.5
Red Desert	4.0	2	0.3	56	3.7
Wamsutter Arch	1.1	1	0.3	13	0.8
Green River Deep	3.2	1	0.2	62	3.0
Pinedale	2.7	-	-	28	2.7
Washakie Deep	1.3	-	-	33	1.3
Sand Wash Deep	1.3	-	-	24	1.3
East Sand Wash	0.7	-	-	17	0.7
Red Desert Deep	0.7	-	-	13	0.6
Cherokee Arch	0.4	-	-	9	0.4
East Washakie	0.4	-	-	9	0.4
Dad Dix	0.2	-	-	4	0.2
TOTALS	23.6	14	4.3	351	19.2

Table 3-5

Frontier Advanced Case

Partitions	Technically Recoverable Resource (Tcf)	Economically Recoverable Resources			
		<$3 Gas Township Count	Recover. Resource (Tcf)	<$3 Gas Township Count	Recover. Resource (Tcf)
Red Desert	7.0	16	5.0	42	2.0
Hoback	4.2	9	3.4	19	0.8
Farson Deep	4.6	5	3.3	17	1.3
Pinedale	4.7	9	2.9	19	1.8
Green River Deep	5.5	11	2.7	52	2.8
Vermilion	1.8	6	1.6	8	0.2
Washakie West	1.4	4	1.2	5	0.2
Wamsutter Arch	1.9	3	1.2	11	0.7
West of Moxa Arch	1.7	2	0.9	18	0.7
Red Desert Deep	1.0	2	0.6	11	0.4
Sand Wash Deep	2.2	2	0.5	22	1.7
East Sand Wash	1.3	3	0.4	14	0.8
Cherokee Arch	0.6	2	0.4	7	0.2
Dad Dix	0.3	1	0.2	3	0.1
East Washakie	0.6	1	0.1	8	0.5
Washakie Deep	2.4	-	-	33	2.4
TOTALS	41.2	76	24.5	289	16.8

Table 3-6

Mesaverde Base Case

Partitions	Technically Recoverable Resource (Tcf)	Economically Recoverable Resources			
		<$3 Gas Township Count	Recover. Resource (Tcf)	<$3 Gas Township Count	Recover. Resource (Tcf)
Pinedale	19.7	5	11.4	23	8.3
Sand Wash Deep	13.1	5	6.8	20	6.3
Hoback	11.2	3	5.3	25	5.9
Wamsutter Arch	7.1	4	4.9	11	2.2
Farson Deep	6.0	1	3.0	10	3.0
Red Desert	12.9	2	2.0	62	10.9
Cherokee Arch	2.5	2	1.9	6	0.7
East Sand Wash	3.3	1	1.2	11	2.1
Washakie Deep	8.4	1	1.1	32	7.4
East Washakie	2.1	1	0.8	8	1.3
Red Desert Deep	0.8	-	-	9	0.8
TOTALS	87.1	25	38.4	217	48.7

Table 3-7

Mesaverde Advanced Case

Partitions	Technically Recoverable Resource (Tcf)	Economically Recoverable Resources			
		<$3 Gas Township Count	Recover. Resource (Tcf)	<$3 Gas Township Count	Recover. Resource (Tcf)
Pinedale	27.5	12	21.8	16	5.7
Sand Wash Deep	18.4	10	13.2	15	5.2
Hoback	15.8	7	10.6	21	5.2
Wamsutter Arch	9.9	6	8.3	9	1.7
Red Desert	18.4	8	7.1	56	11.3
Farson Deep	8.5	4	6.4	7	2.0
Washakie Deep	12.0	5	4.6	28	7.4
East Sand Wash	4.7	3	2.8	9	1.9
Cherokee Arch	3.5	2	2.6	6	0.9
East Washakie	3.0	2	1.6	7	1.4
Red Desert Deep	1.1	-	-	9	1.1
TOTALS	122.8	59	78.9	183	43.9

Appendix A

ARI Presentation from the DOE-FETC
Oil & Gas Conference, Dallas, Texas
Session 3A, June 30, 1999

"Low Cost Methods for Finding Tight Gas, Gas Shales and Coalbed Methane"

By

Vello A. Kuuskraa

David J. Campagna

Advanced Resources International, Inc.

DOE-FETC Oil & Gas Conference, Dallas, Texas

Session 3A

June 30, 1999

Discussion Outline

1. Importance of Tight Gas, Gas Shales and Coalbed Methane

2. The Exploration Challenge: Favorable Natural Fracture Settings

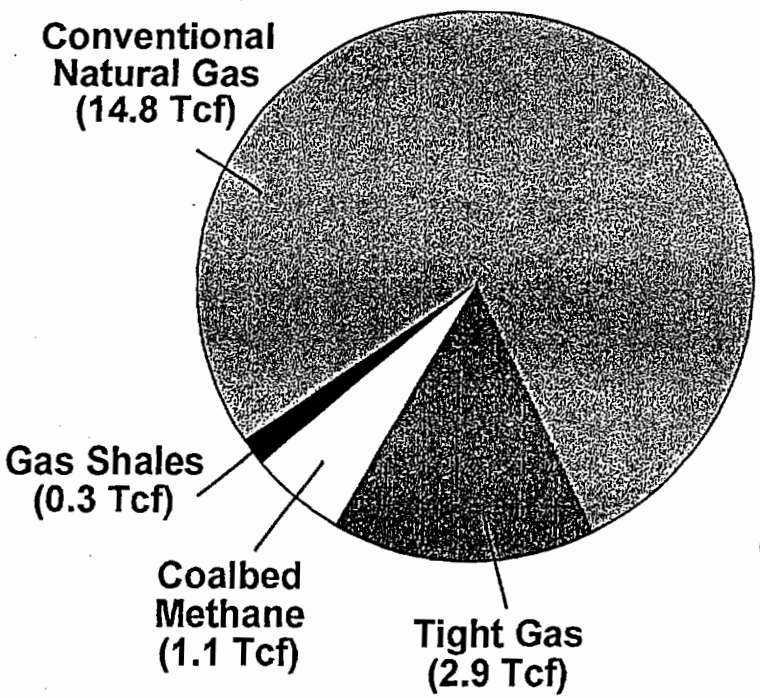
3. Successful Case Studies
   - *Southern Piceance Basin (Rulison)*
   - *Eastern Green River Basin (Table Rock)*

Importance of Tight Gas, Gas Shales and Coalbed Methane

- Tight Gas, Gas Shales and Coalbed Methane are fastest growing part of gas supply:
  - *23% of gas production*
  - *31% of gas reserves*
- Seven of top eleven natural gas fields produce "unconventional gas".
- Largest undeveloped portion of natural gas resource base.

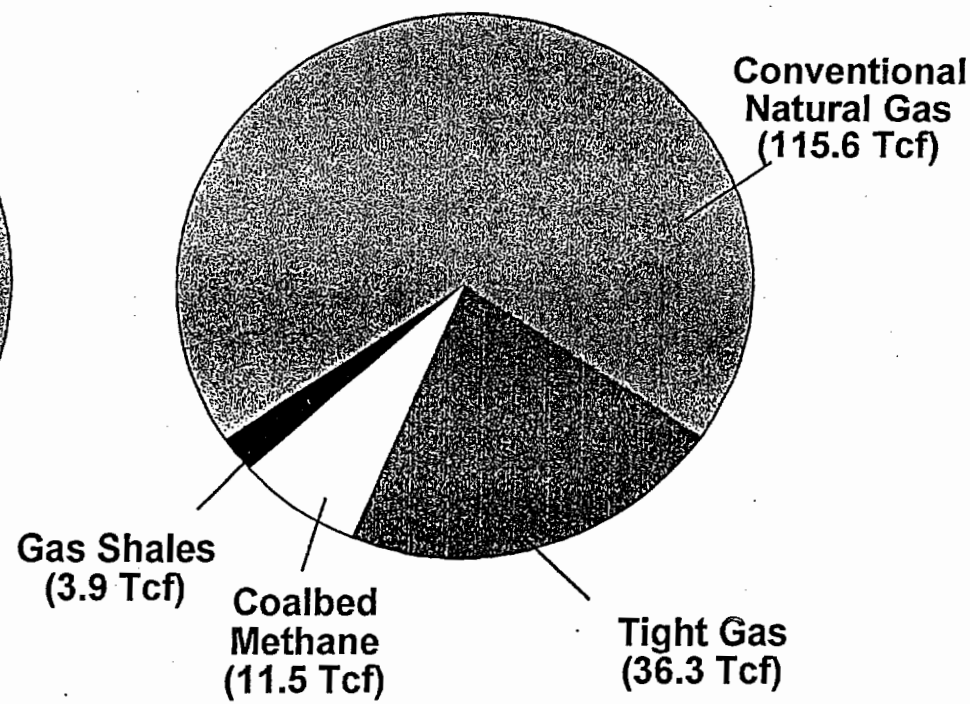
Tight Gas, Gas Shales and Coalbed Methane Are Already Essential Components of U.S. Natural Gas Supply

23% of Total Gas Production



Total Production = 19.2 Tcf

31% of Total Gas Reserves



Total Reserves = 167.2 Tcf

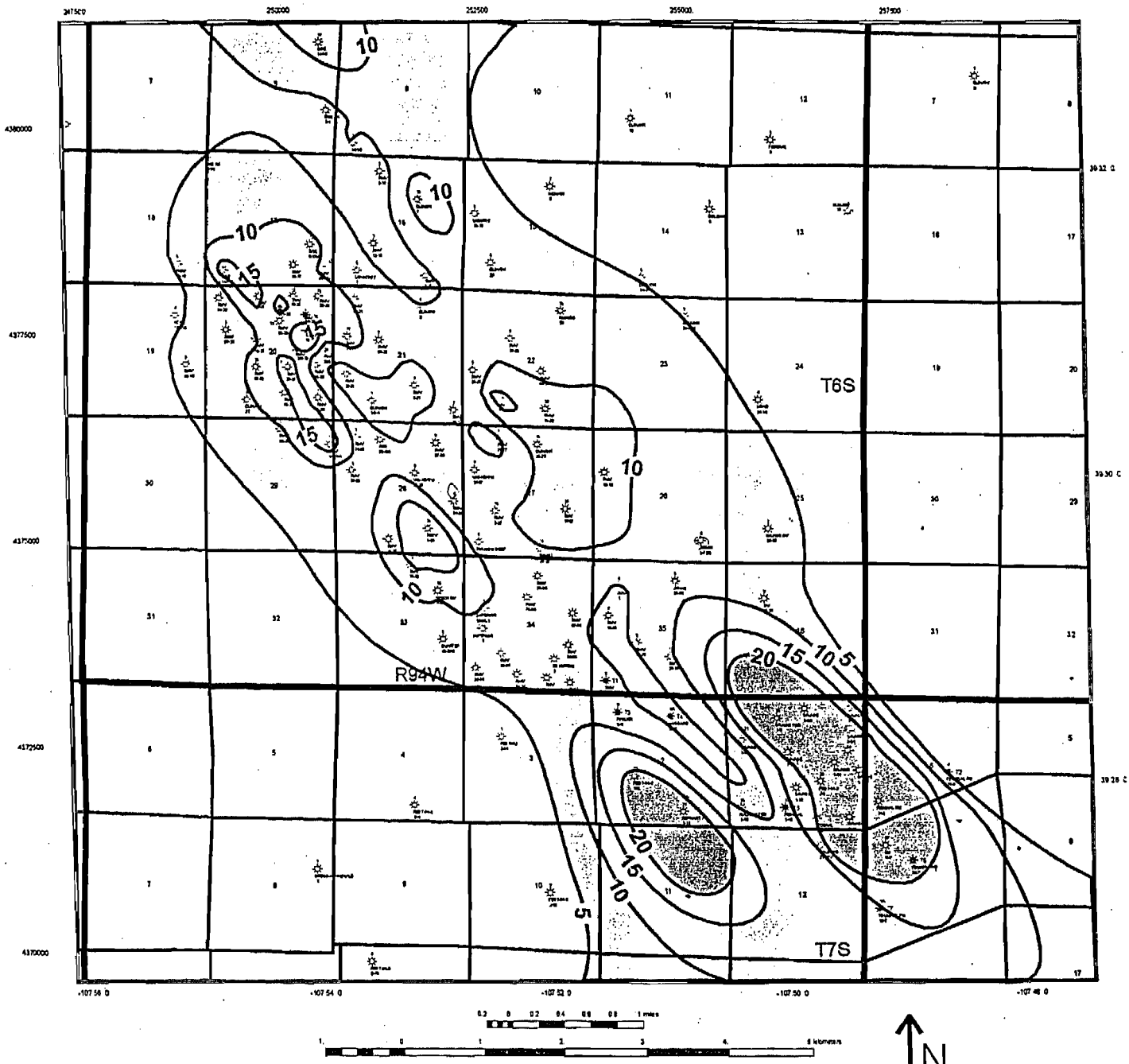
U.S. Natural Gas Fields Producing Tight Gas, Gas Shales and Coalbed Methane

Rank	Field	Basin	State	1997 Gas Production (Bcf)
1.	Basin	San Juan	NM	787
2.	Blanco	San Juan	NM/CO	606
4.	Giddings	Austin Chalk	TX	383
5.	Carthage	East Texas	TX	212
7.	Antrim	Michigan	MI	123
9.	Bob West	Gulf Coast	TX	106
11.	Wattenberg	Denver	CO	95

The Exploration Challenge

- Increase success by locating naturally fractured "sweet spots", *prior to drilling*.
- Highly productive "sweet spots" occur where:
  - *Local natural fracture clusters overprint the regional natural fracture system.*
  - *Local natural fracture system coincides with thick, gas-charged pay.*

Map View of Williams Fork Reservoir Permeability, Rulison Field



Permeability Contours -- 5 md

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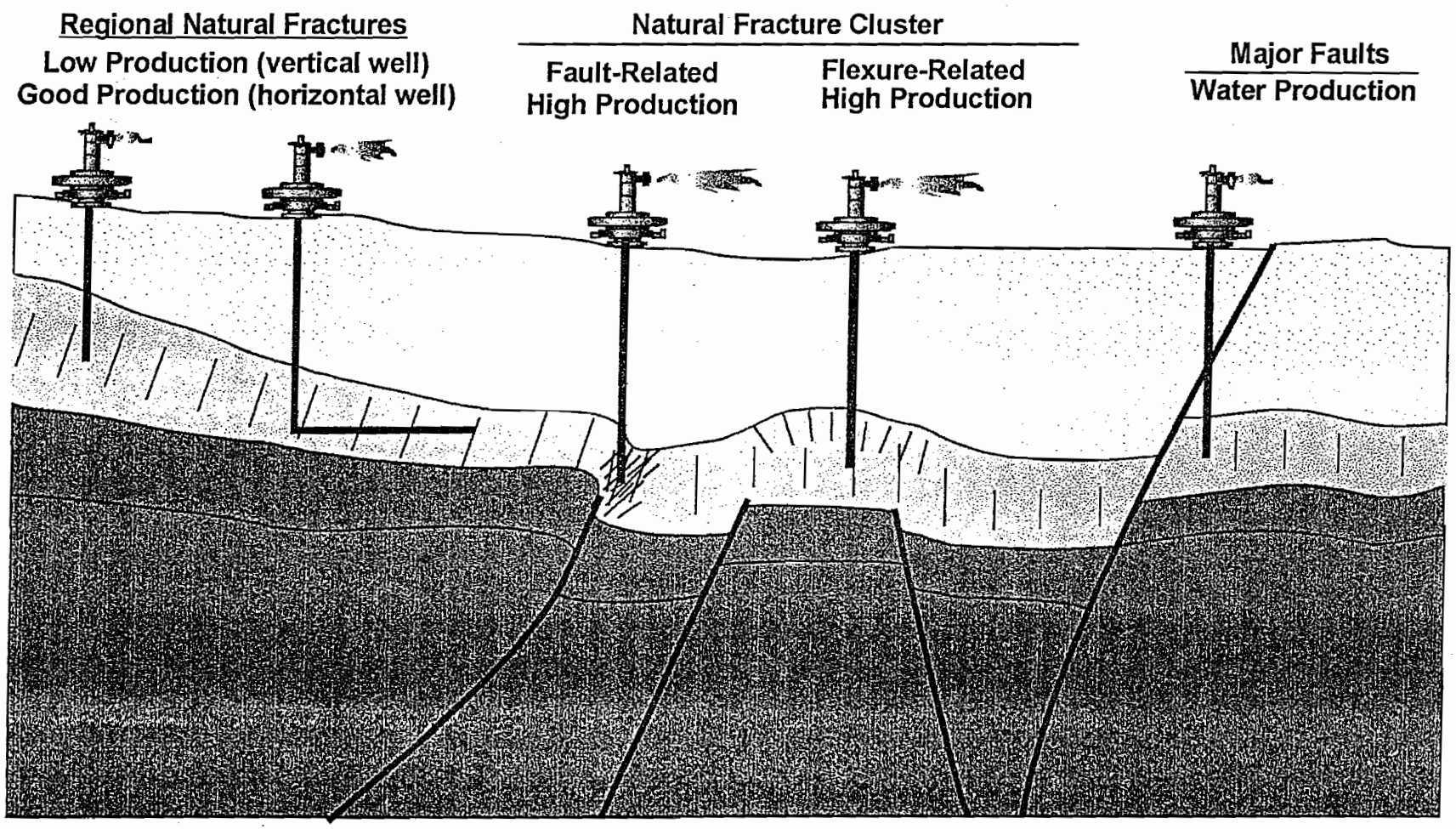
Distribution of Natural Fractures and "Sweet Spots"

- Local, one to ten sections in size, areas of fracture enhanced permeability exist in low-permeability reservoirs.
- These fault-related fractured areas can be located with seismic and geomechanical methods.
- The randomness of well behavior in fractured reservoirs is due to sampling not fundamental geology.

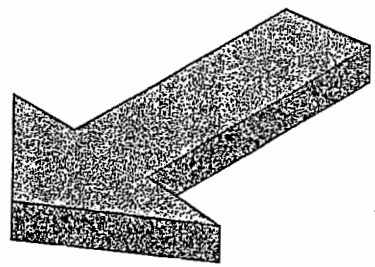
The Exploration Challenge: Finding Favorable Natural Fracture Settings

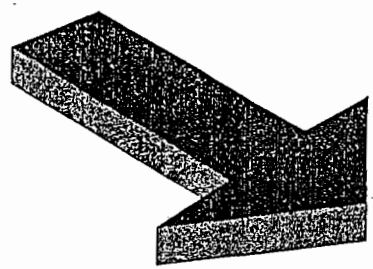


Fractured Reservoir Development Strategy

Basin and Regional High-Grading

Remote Sensing for Surface Features
Gravity and High Resolution Aeromagnetics
Calibration with Subsurface Data



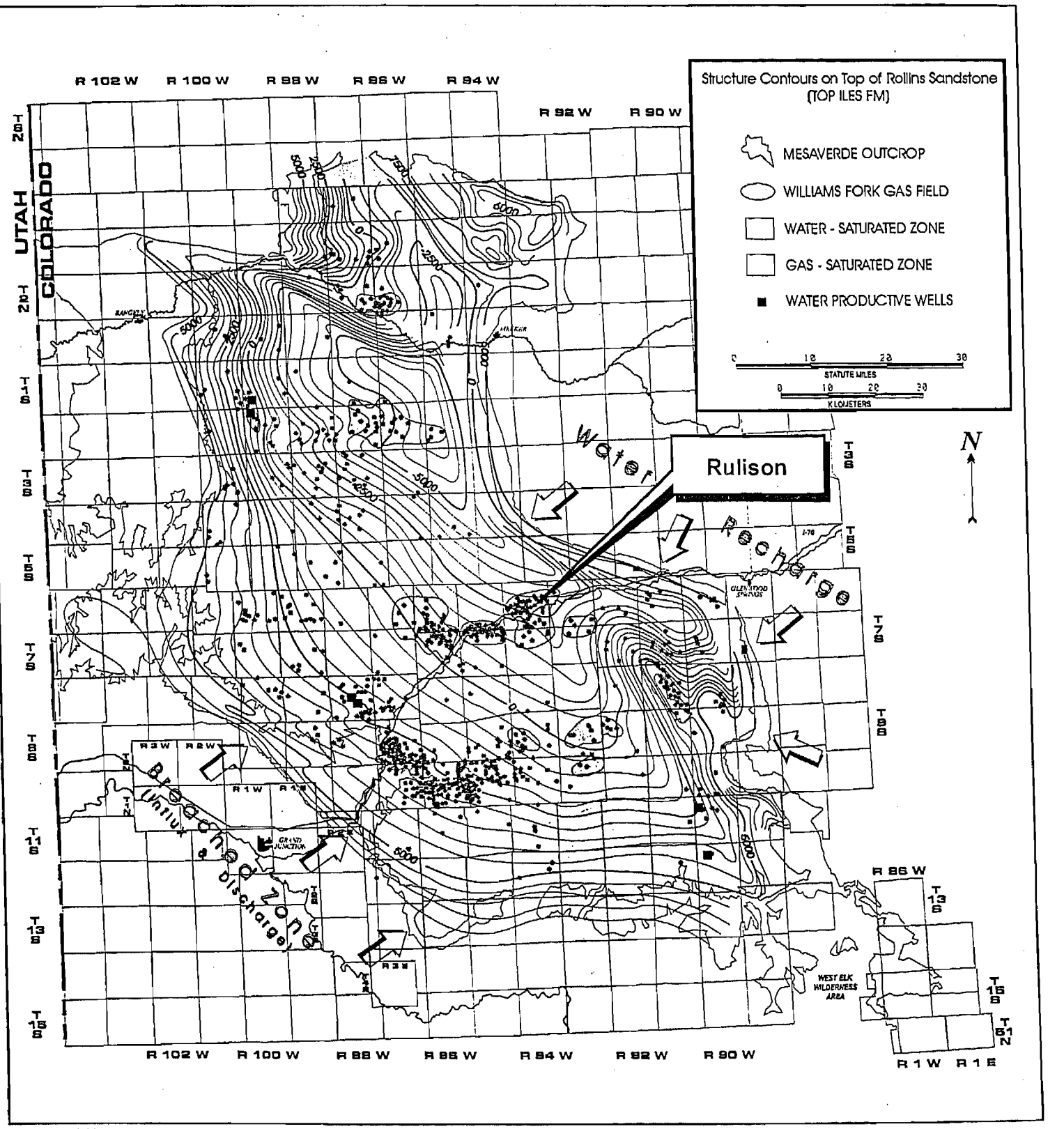


Statistical/Step Out Approach

Prospect Definition

Rulison Field Case Study

Williams Fork Fm, Piceance Basin



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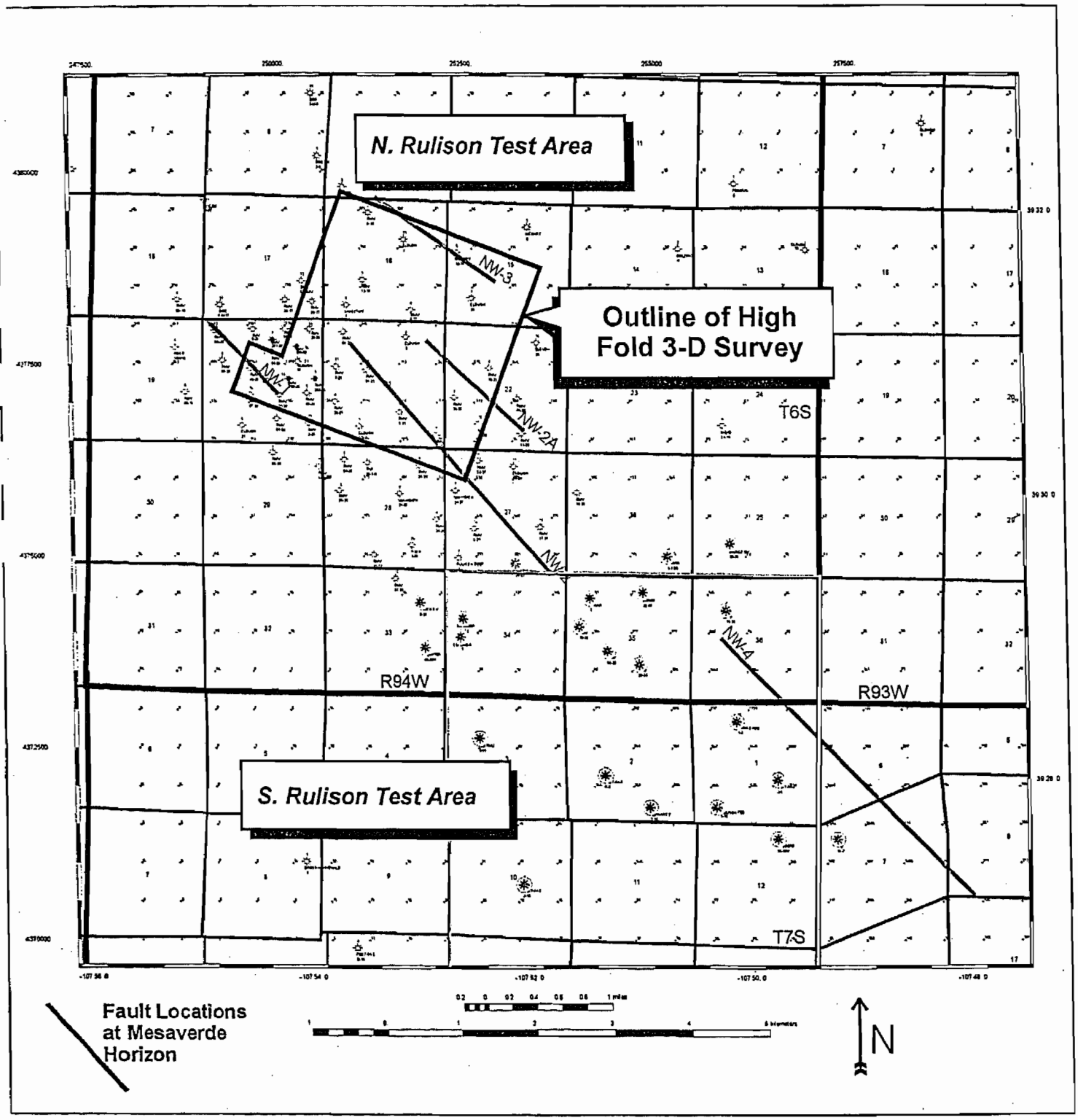
North and South Rulison Test Areas and 3-D Seismic Survey

Development Objective (in mid-'96) was to Extend the Rulison Field to the South-East



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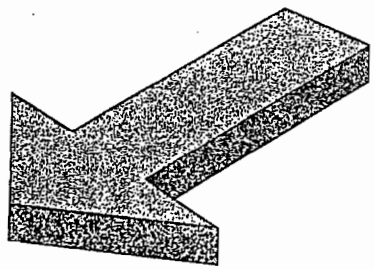
Fractured Reservoir Development Strategy

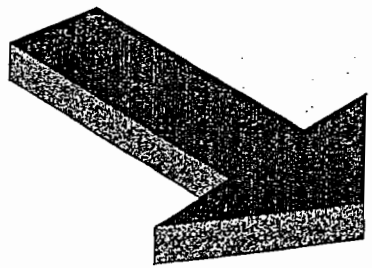
Basin and Regional High-Grading

Remote Sensing for Surface Features
Gravity and High Resolution Aeromagnetics
Calibration with Subsurface Data



Statistical/Step Out Approach

- Multiple Well Drilling Program

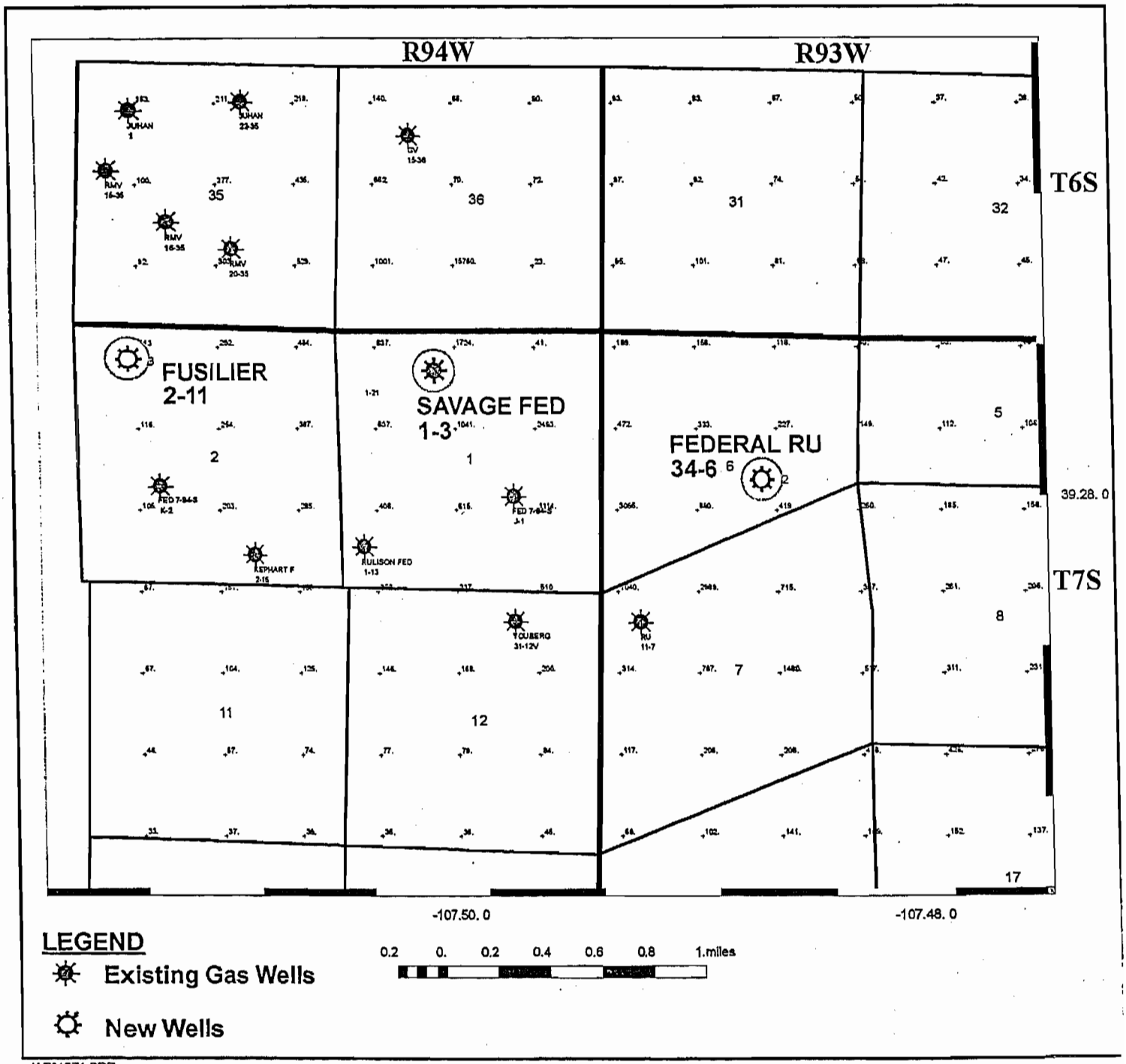


Prospect Definition

- Seismic
- Geomechanical Modeling

South Rulison Field, Piceance Basin

Dramatic Changes In Well Performance Are A Characteristic of the Williams Fork Fm



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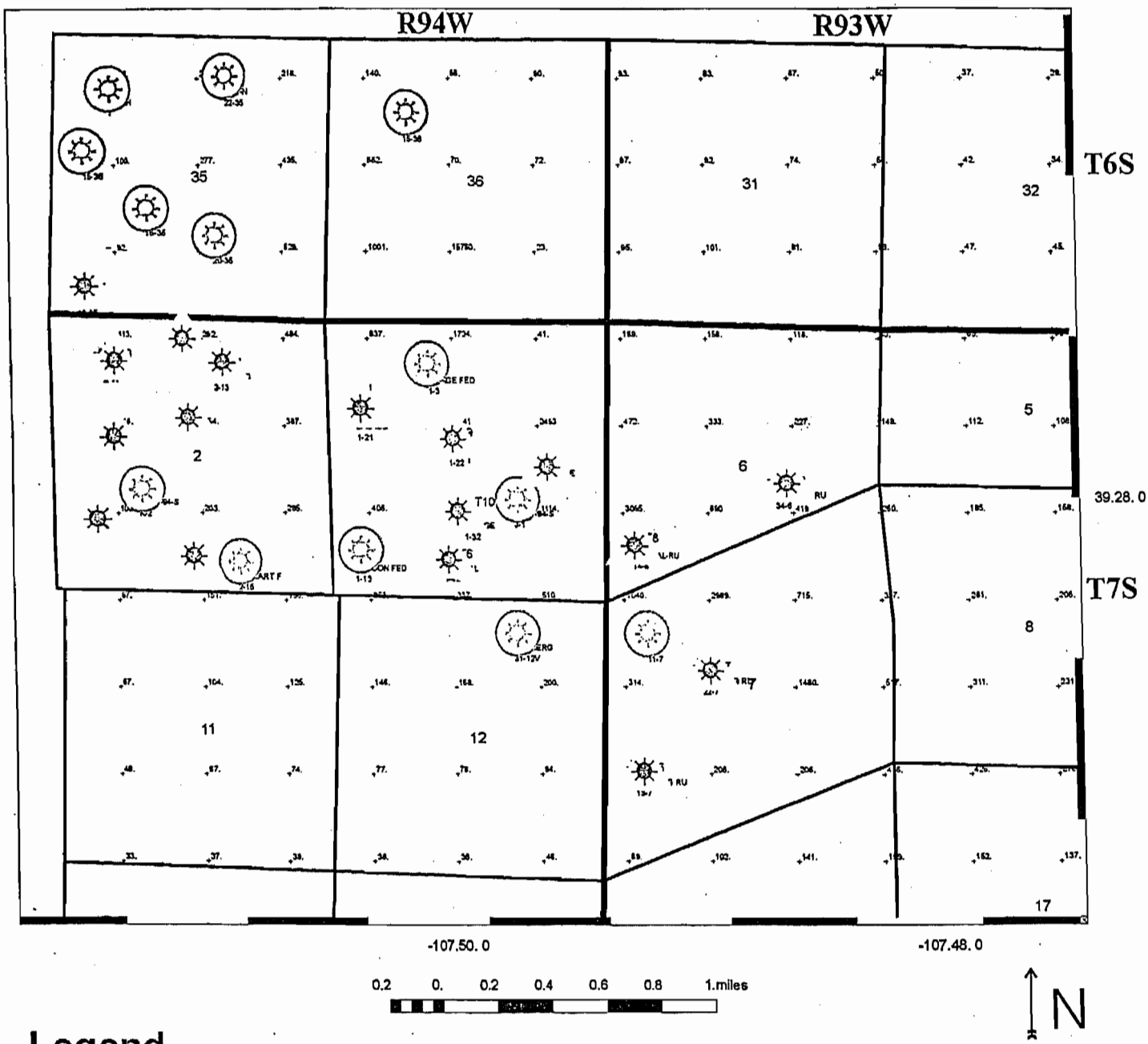
Performance of Three Closely Spaced Wells, S. Rulison Field

	Well #1 Fusilier 2-11 (Sec. 2, T7S, R94W) (Compl. 7/97)	Well #2 Savage Fed 1-3 (Sec. 1, T7S, R94W) (Compl. 2/95, Rec. 10/96)	Well #3 Federal RU 34-6 (Sec. 6, T7S, R93W) (Compl. 12/96)
EUR	0.9 Bcf	4.5 Bcf	0.3 Bcf
NET PAY	300 ft	322 ft	285 ft
Porosity	9.8%	10.60%	12.2%
Permeability	4 md	14 md	2 md

South Rulison Field, Piceance Basin

By Early '98, 35 Wells Completed Using Statistical/Step Out Drilling



Legend

Exploration/Validation Wells (17) (13 Represented)

Step Out/Delineation Wells (18) (17 Represented)

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S. Rulison: Step Out Approach

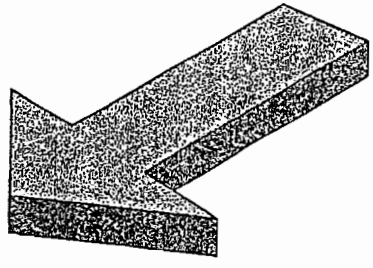
1. Exploration and Validation
   - *17 wells (1990-96)*
   - *$15.3 million**
2. Step Out and Delineation
   - *18 wells (1996-Present)*
   - *$16.2 million*
3. Results:
   - *Reserves 63 Bcf*
   - *Total Costs - $31.5 million*

**Assuming $0.9 million per well.*

Fractured Reservoir Development Strategy

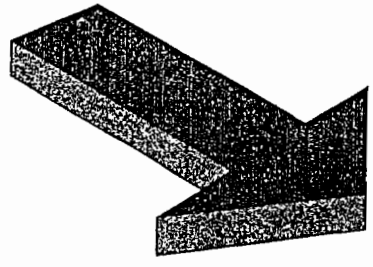
Basin and Regional High-Grading

Remote Sensing for Surface Features
Gravity and High Resolution Aeromagnetics
Calibration with Subsurface Data



Statistical/Step Out Approach

- Multiple Well Drilling Program

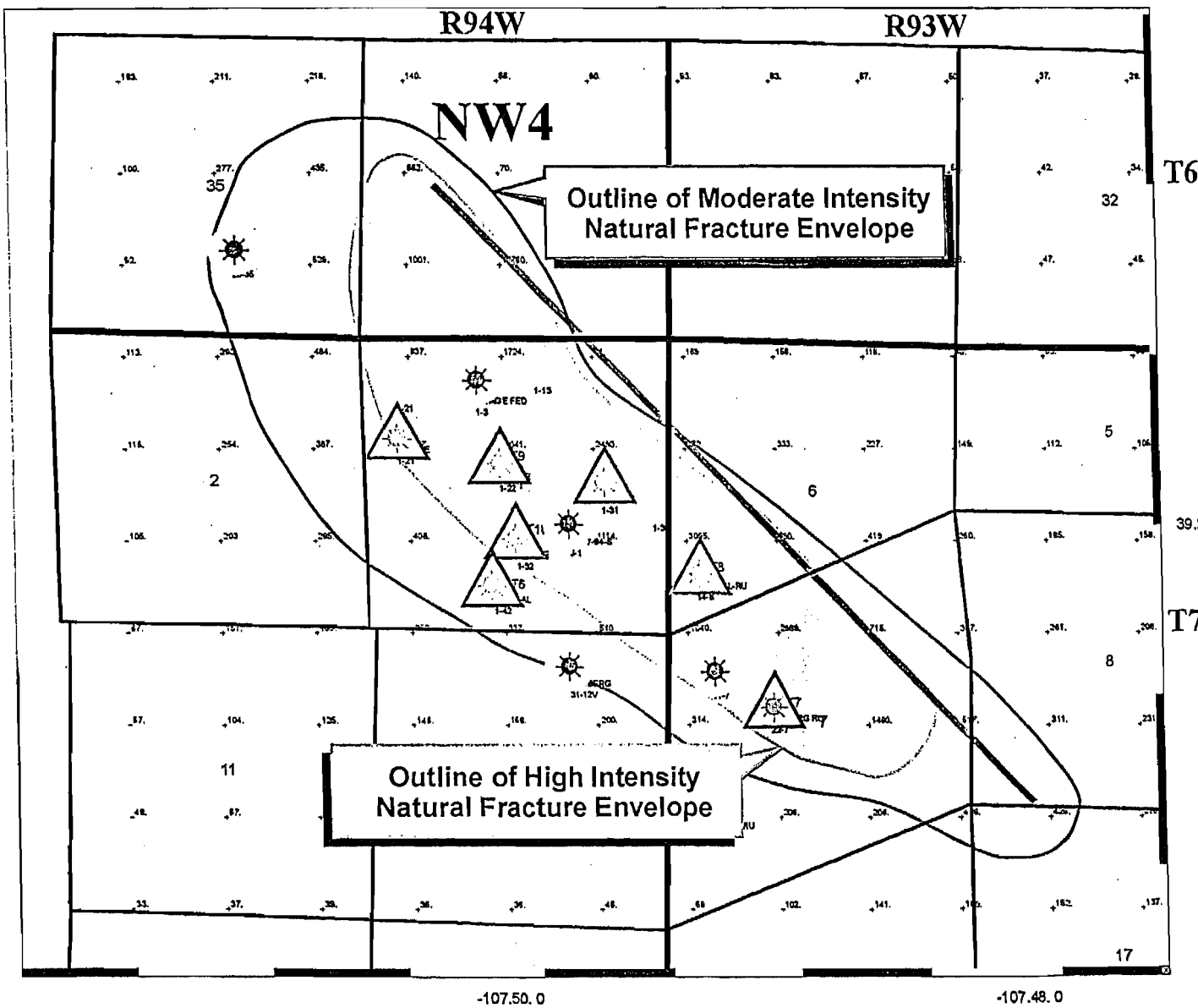


Prospect Definition

- Seismic
- Geomechanical Modeling

South Rulison Field, Piceance Basin

Alternative is Using Prospect Definition (Seismic and Geomechanics) to Locate Wells in Naturally Fractured "Sweet Spots"



Legend

- Exploration/Validation Wells (5)
- Step Out/Delineation Wells (7)

JAF01286.CDR

S. Rulison: Prospect Definition Approach

1. **Exploration and Validation**
   - *72 square miles 3-D seismic, plus geomechanical analysis*
   - *5 wells*
   - *$6.6 million**

2. **Step Out and Delineation**
   - *7 wells*
   - *$6.3 million*

3. **Results:**
   - *Reserves 40 Bcf*
   - *Total Costs - $12.9 million*

**Assuming $1.8 million for seismic survey, $0.3 million for analysis, $0.9 million per well.*

Comparison of Step Out Approach vs. Prospect Definition

	Step Out Approach	Prospect Definition
• Costs*	$31.5 MM	$12.9 MM
• Reserves	63 Bcf	40 Bcf
• Wells	35	12
• Reserves/Well	1.8 Bcf	3.4 Bcf
• Finding Costs @85% NRI	$0.59/Mcf	$0.38/Mcf

**Includes $0.9 million per well and $2.1 million for seismic and geomechanical analysis.*

Cost Savings From Using Prospect Definition (Seismic and Geomechanics) for Efficient Field Development (S. Rulison Example)

	Statistical/ Step Out Approach	Prospect Definition
Target Reserves	1,000 Bcf	1,000 Bcf
Average EUR/Well	1.8 Bcf*	3.4 Bcf**
No. of Wells	556	294
Capital Costs*** (@$900,000/well)	$500 million	$267 million
Cost Savings		**$233 million**

*Average EUR for 35 wells statistically drilled in S. Rulison area.
**Average EUR for 12 wells located and drilled in naturally fractured envelope
***Capital costs of Prospect Definition include $2.1 million for seismic and geomechanical analysis.

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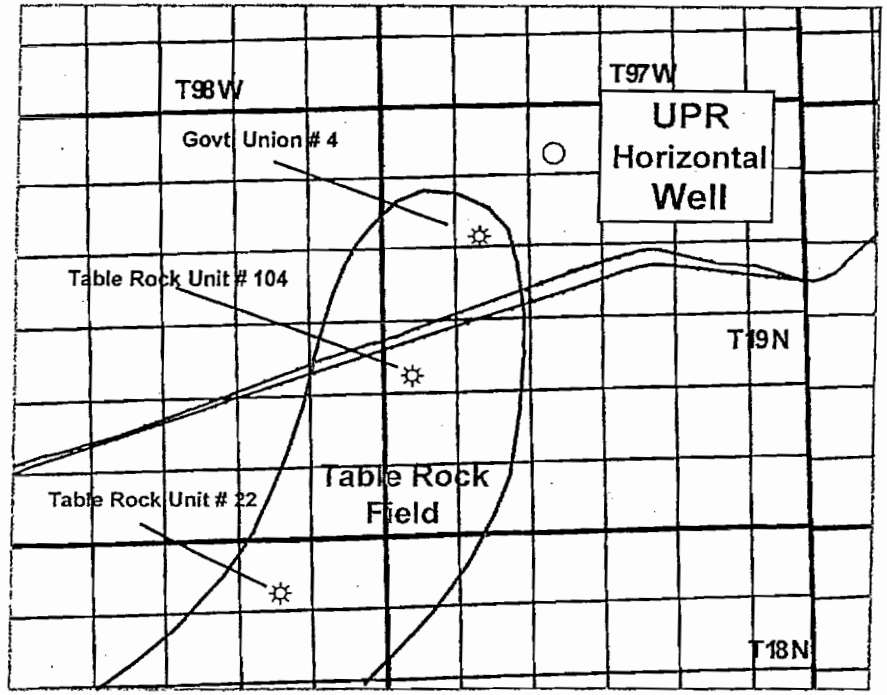
Table Rock Field Case Study
Frontier Fm., Green River Basin

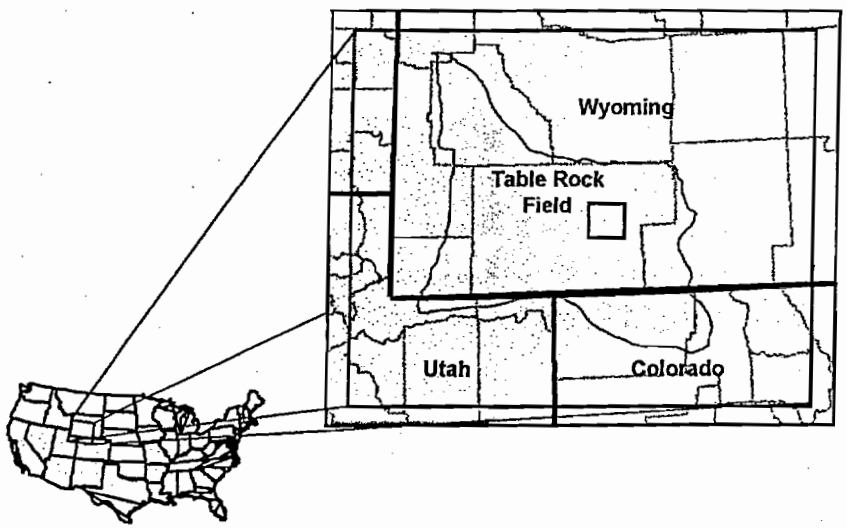
Deep, High Risk Frontier Fm. Reservoir

- *15,000'; 270° F; 10,000 psi*
- *Unsuccessful exploration well at Frewen*
- *World record tight gas horizontal well*

Table Rock Field



Greater Green River Basin



Prospect Corroboration

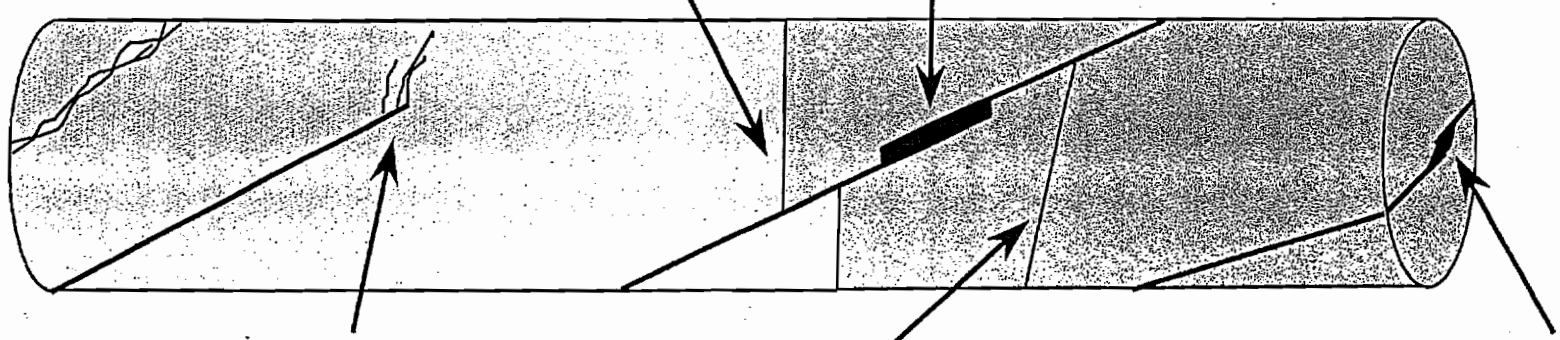
Given expense and risk of horizontal drilling, statistical approach to locating exploration wells in deep, high-risk Frontier Fm is not viable.

ARI's role was to corroborate the horizontal well location using the Prospect Definition approach:

- *Natural Fracture Characterization*
- *Fault Mapping Using 3-D Seismic*
- *Geomechanical Modeling*

Natural Fracture Characterization: Table Rock, Green River Basin

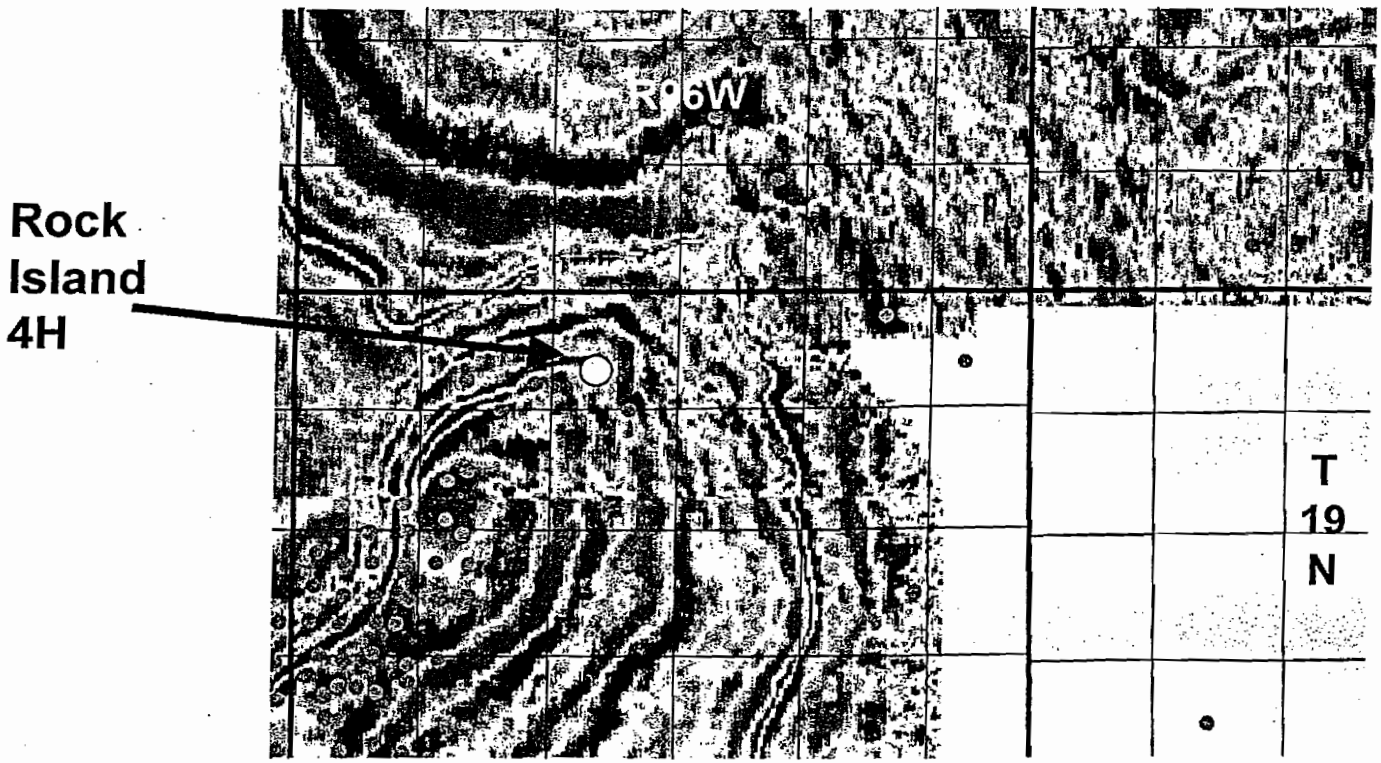
- Natural fractures in Frontier Fm are dominantly oblique-reverse shears with extensional component.
- Open voids provide storage; <u>shear fractures</u> provide permeability.



Natural Fractures Observed in Core

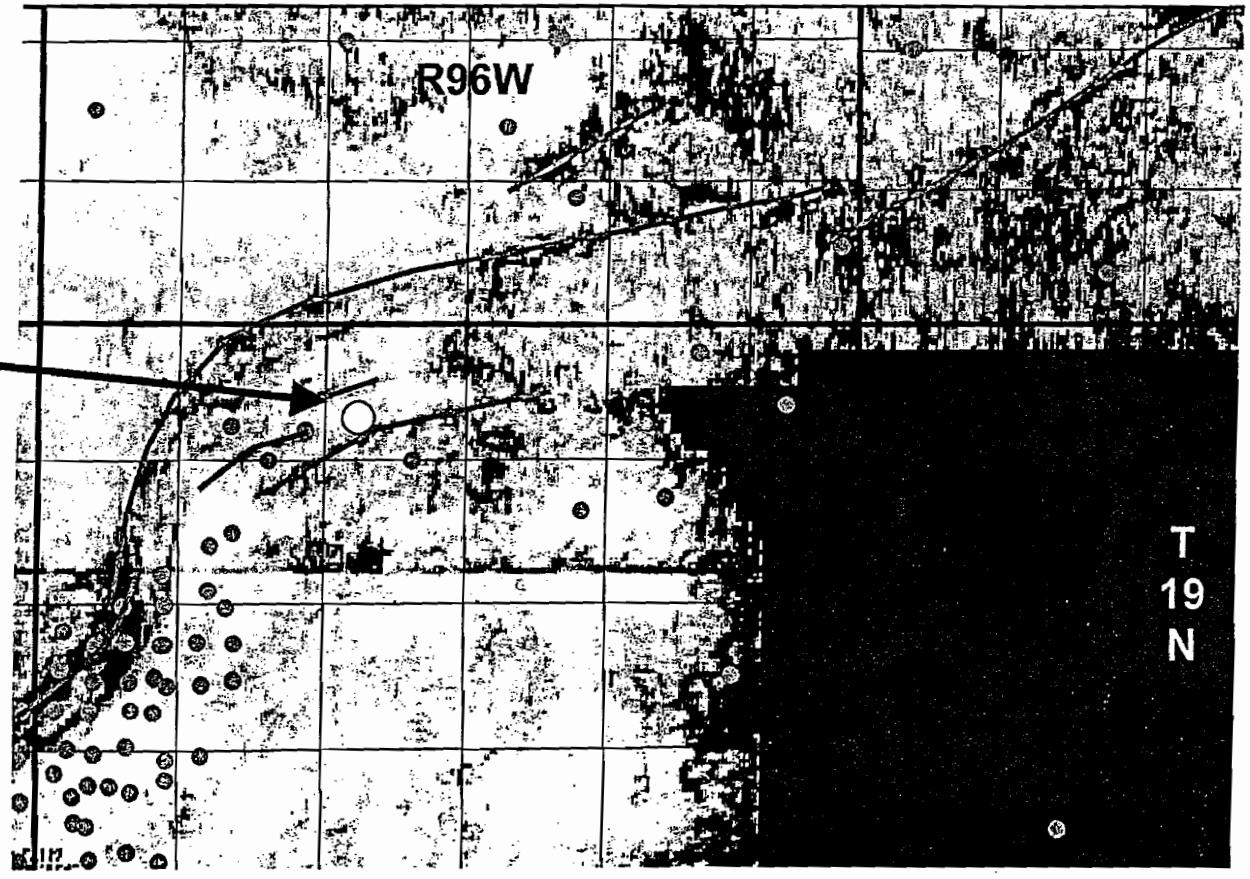
3D Seismic: Depth Slice 16,000'

Location of Rock Island 4H is on the northern nose of the Table Rock fold (off-structure).



3D Seismic: Fault Mapping

Subtle faults and complex geometry of the main thrust and strike-slip fault system are revealed after coherency filtering.



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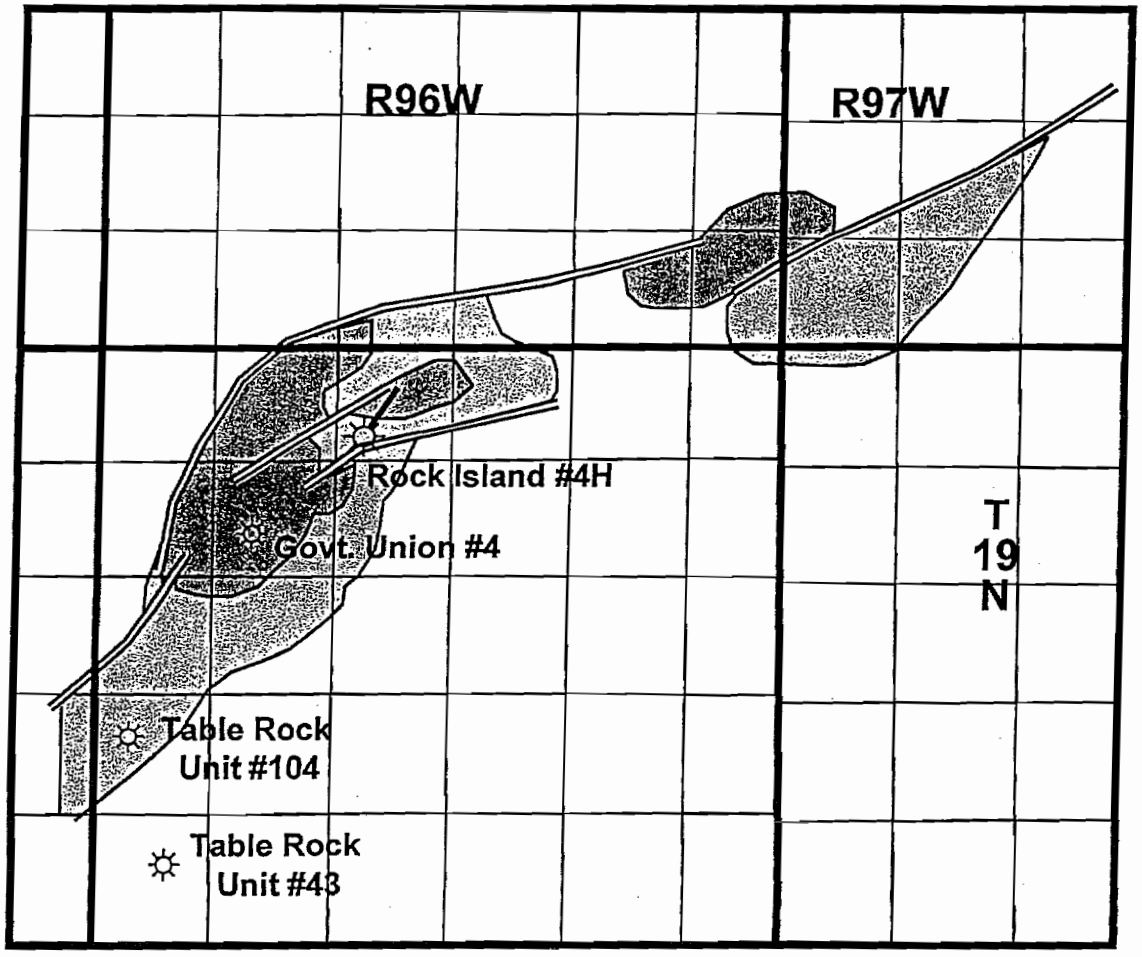
Natural Fracture Prediction: Geomechanical Model Results

The Rock Island 4H occupies an area between two small faults and may have hit a zone of enhanced stress concentration.



Prospect Definition Results

Monday April 26, 10:55 am Eastern Time

UPR'S HORIZONTAL WELL TESTED AT OVER 12 MMCFD

Union Pacific Resources Group, Inc., Working with Federal Energy Tech Center, Completes Experimental Horizontal Frontier Formation Gas Well

Value of Using Seismic and Geomechanics for Prospect Definition

1. Play Assessment. Provides viable leads for an economic tight gas exploration program.

2. Exploration Success. Helps avoid "program killers", early dry holes.

3. Efficient Development. Provides a low cost approach for developing low-permeability gas fields.

Summary

1. *Tight Gas, Gas Shales and Coalbed Methane Can Provide Large, Economic Resource Targets.*

2. *Prospect Definition, Using the Geomechanical Approach to Natural Fracture Prediction, Is a Cost-Effective Alternative to Step Out and Statistical Drilling.*

Summary

3. *The Geomechanical Approach Provides a Low Cost, Advanced Exploration Tool for Naturally Fractured Reservoirs:*
   - *2D and 3D seismic data*
   - *Standard seismic processing*
   - *Available numerical simulator*

4. *Successful Results Have Been Achieved at Rulison (and Mamm Creek), Piceance Basin and Table Rock, Green River Basin.*

Appendix B

ARI Presentation from the DOE-FETC
Oil & Gas Conference, Dallas, Texas
Pre-Conference Workshop
June 28, 1999

The Geomechanical Approach in Exploring for Naturally Fractured Reservoirs:

Piceance Basin and Greater Green River Basin Case Studies

David J. Campagna
Advanced Resources International

Pre-Conference Workshop

"Exploring For and Developing Naturally Fractured Low-Permeability Gas Reservoirs: From the Rocky Mountains to the Austin Chalk"

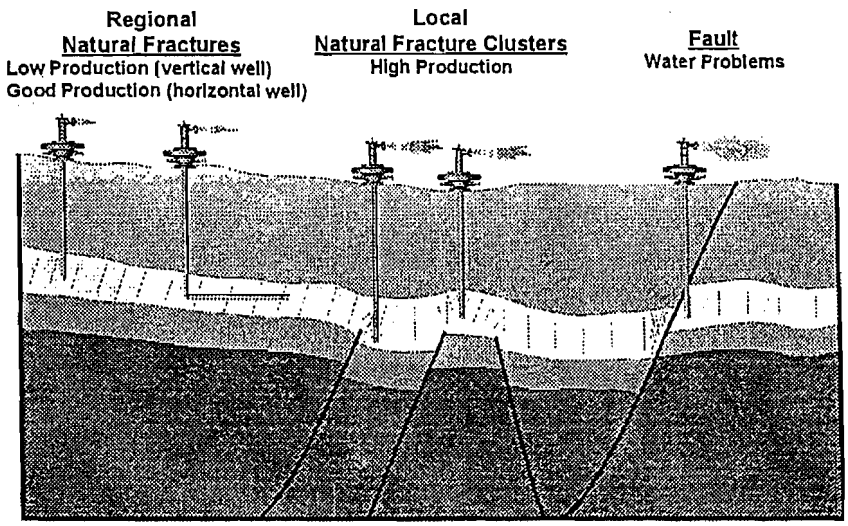
DOE Federal Energy Technology Center 1999 Oil & Gas Conference

Dallas, Texas 28 June 1999

Outline

1. *Natural Fracture Settings*
2. *The Geomechanical Approach*
3. *Case Study 1: Rulison Field, Piceance Basin, Colorado*
4. *Case Study 2: Table Rock Field, Greater Green River Basin, Wyoming*
5. *Concluding Remarks*

Natural Fracture Settings in the Rocky Mountain Basins



Geomechanical Approach

The geomechanical approach provide the means to detect the occurrences and characteristics of natural fractures around faults and thus allow the prediction of fracture-related reservoir "sweet spots."

Advantages include:

- Scientifically rigorous method
- Inputs from standard seismic data and analysis
- Economic - less expensive than advanced seismic detection techniques such as shear wave.

Geomechanical Approach: Objectives & Methods

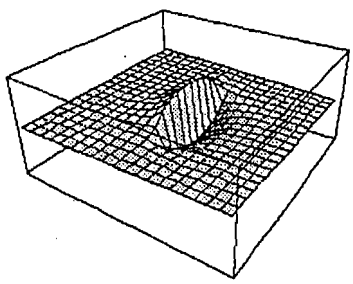
Objectives : To predict location and orientations of natural fractures that form due to fault-related deformation.

Methods: 3D numerical model (Boundary Element Method or Finite Element Method) that solves linear elastic equations for stress and displacement.

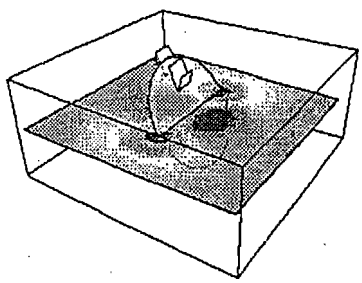
The BEM method is limited to modeling failure due to displacement and stress perturbations along a discontinuity (fault, fracture).

Geomechanical Approach: BEM Numerical Method

Poly3D is a three dimensional, BEM numerical code which solves the elastostatic equations for displacement and stress.



Calculated displacements around a normal fault

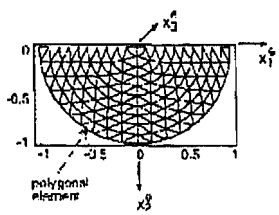


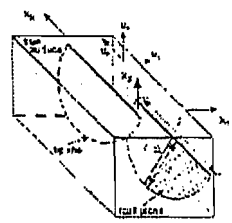
Calculated stress concentrations around a normal fault

From: Laurent Maertien, Stanford Rock Fracture Project web page, 1999

Geomechanical Approach: Input Criteria

- **Inputs into model include:**
  - XYZ coordinates of fault geometry,
  - Displacement across faults or the orientation of remote stresses deduced from displacement geometry
  - Material properties (Poisson's ratio & shear modulus).
  - Frictional component, μ, was assigned 0.6, typical of sandstones.



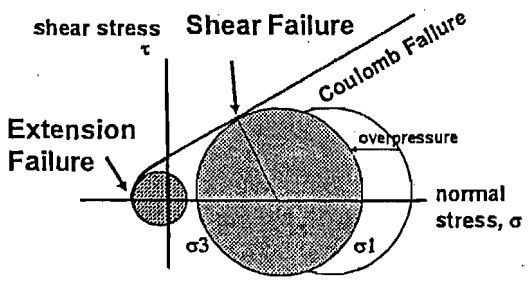


Geomechanical Approach: Failure Criterion

To evaluate the mechanical genesis of secondary shear fractures, a failure criterion is applied.

The maximum Coulomb shear stress (Sc), for example, can be used to as an indicator of shear failure.

$$S_c = ((\sigma 1 - \sigma 3)/2) * (1+\mu^2)^{1/2}) + \mu * \{(\sigma 1 + \sigma 3)/2\}$$



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

Case Studies

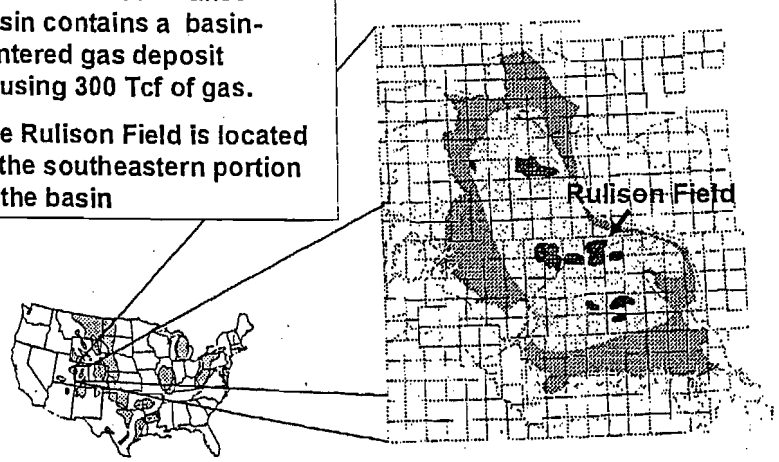
Two case studies in the Rocky Mountains region are presented where the geomechanical approach was tested.

- Piceance Basin, Colorado
  - Rulison Field: The first application of the geomechanical approach.
- Greater Green River Basin
  - Table Rock Field: A second test of the geomechanical approach in conjunction with Union Pacific resources/FETC horizontal drilling project.

Rulison Field, Piceance Basin, Colorado

The southern Piceance Basin contains a basin-centered gas deposit housing 300 Tcf of gas.

The Rulison Field is located in the southeastern portion of the basin



Rulison Field: Reservoir Characteristics

The Rulison field produces from the over-pressured tight sands of the Williams Fork Fm. of the Cretaceous Mesaverde Group.

- Characteristics of the reservoir include:
  - Drilling depths 6500-7500'
  - Net pay 300-500'
  - Porosity 8-12%
  - Water saturation 35%
  - Permeability 5μd (1-20μd)

Rulison Field: Variability of Well Performance

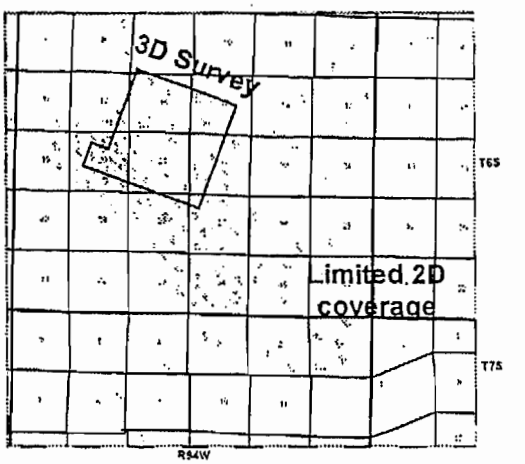
Well performance varies dramatically in the field. The wells below are separated by less than a mile, completed in the same interval, with the same stimulation techniques.

	Fusilier 2-11 (Sec. 2, T7S, R94W) (Compl. 7/97)	Savage Fed 1-3 (Sec. 1, T7S, R94W) (Compl. 2/95, Rec. 10/96)	Federal RU 34-6 (Sec. 6, T7S, R93W) (Compl. 12/96)
Net Pay	300 ft	322 ft	285 ft
Porosity	9.8%	10.60%	12.2%
Permeability	4 md	14 md	2 md
EUR	0.9 Bcf	4.5 Bcf	0.3 Bcf

Rulison Field: 3D Seismic

Advanced Resources with FETC, Barrett Resources, and Western Geophysical, acquired a high-resolution 3D seismic survey over Rulison Field.

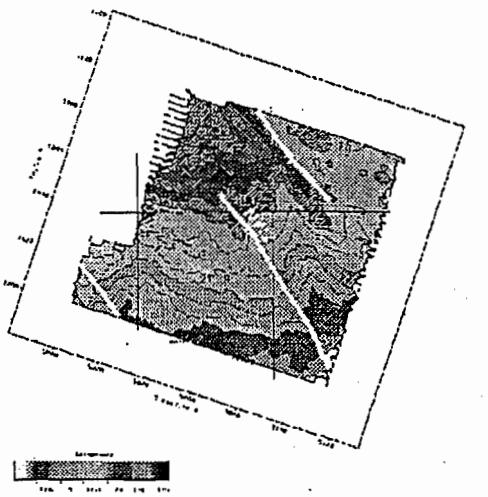
This survey was also used to assess seismic detection of natural fractures using multiazimuth P-wave analysis.



Rulison Field: 3D Seismic

The high-resolution 3D seismic data revealed numerous small reverse faults that cut through the field, faults not mapped previously.

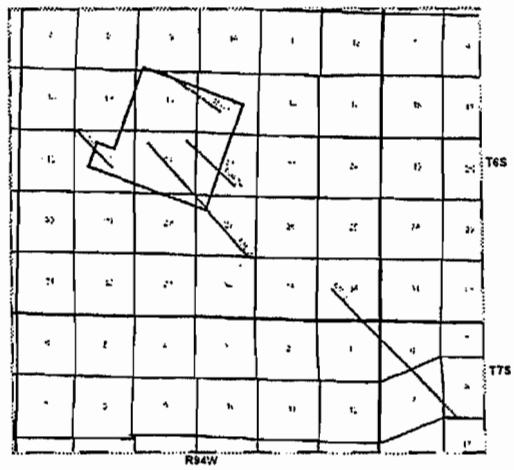
The fault trends correlated loosely with the high-productivity trends and provide evidence for fault-related natural fracture systems.



Rulison Field: Fault Mapping

The area's major faults were mapped using both 3D and 2D seismic data.

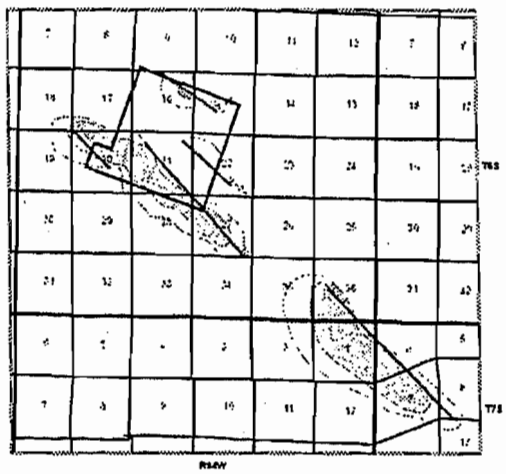
The geometry and relative displacements of these faults provided input into the geomechanical model.



Rulison Field: Geomechanical Model Results

Using a criteria of the maximum tensile failure, regions where tensile stress concentrations occur were mapped.

These regions represent the location where it is more likely that fault-related natural fractures occur.

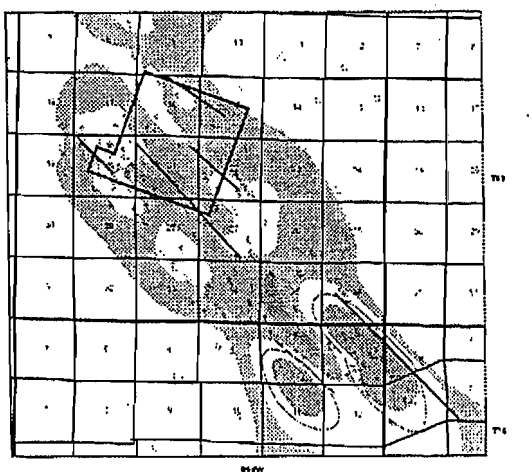


Rulison Field: Permeability Distribution

The distribution of permeability correlates roughly with the mapped natural fracture clusters.

The area in the north did not match very well and may be due to the lack of complete fault mapping in the area.

In contrast, south Rulison Field area, after step-out drilling correlated extremely well.



South Rulison Field: Results Compared With Production

Post-geomechanical results, step out drilling in the south Rulison Field confirm the presence of a highly productive "sweet-spot" in the area identified by the geomechanical model.

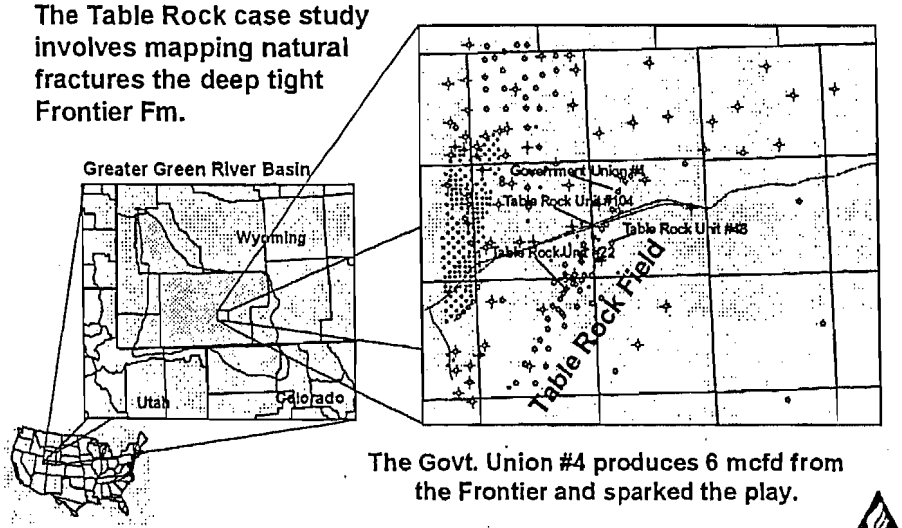
	Wells Inside Naturally Fractured Envelope	Wells Outside Naturally Fractured Envelope
No. Wells	12	23
Average Permeability (μd)	17	6
Average Net Pay (ft)	266	224
Average EUR/Well	3.4 Bcf	1.0 Bcf

Rulison Field: Summary and Implications

- The initial application of the geomechanical approach in the Rulison Field were extremely encouraging.
  - Provided first evidence that reservoir controlled by fault-related natural fracture systems
  - Established a means to map the location of the corresponding "sweet-spot" prior to drilling
- The validity of the geomechanical method deserved testing in another setting
  - Perform in a region with better geologic and seismic control
  - Perform in conjunction with other advanced technologies in exploring for naturally fractured reservoirs.

Table Rock Field, Greater Green River Basin, Wyoming

The Table Rock case study involves mapping natural fractures the deep tight Frontier Fm.



The Govt. Union #4 produces 6 mcfd from the Frontier and sparked the play.

Table Rock Field: Frontier Test

The horizontal drilling effort by Union Pacific Resources and FETC provided an opportunity to test and further develop the geomechanical approach to mapping fault-related natural fracture systems.

The first task involved a test of the geomechanical approach before drilling the horizontal well:

- Natural Fracture Characterization
  - Examination of the Govt. Union #4 and Frewen Deep #4 cores,
- Regional Fault Mapping
  - Table Rock and Continental Divide 3D Surveys
- A preliminary geomechanical model of a regional fault geometry of the Table Rock thrust system.

Table Rock Field: Natural Fracture Characterization

The type of natural fracture observed in core provide clues to their regional or local origin.

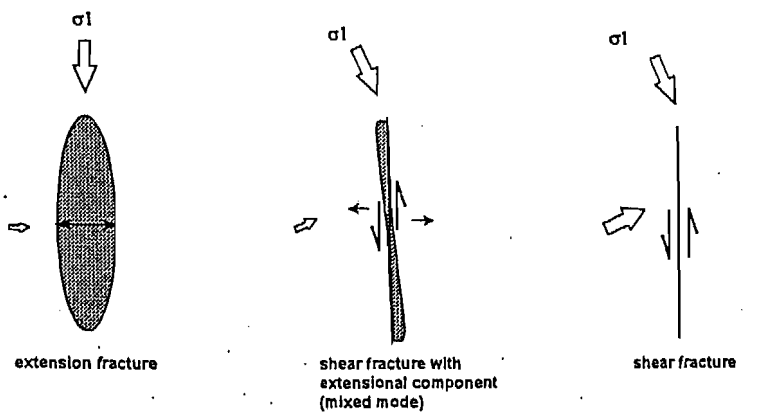


Table Rock Field: Natural Fracture Characterization

Shear(ed) fractures are identified in core by:

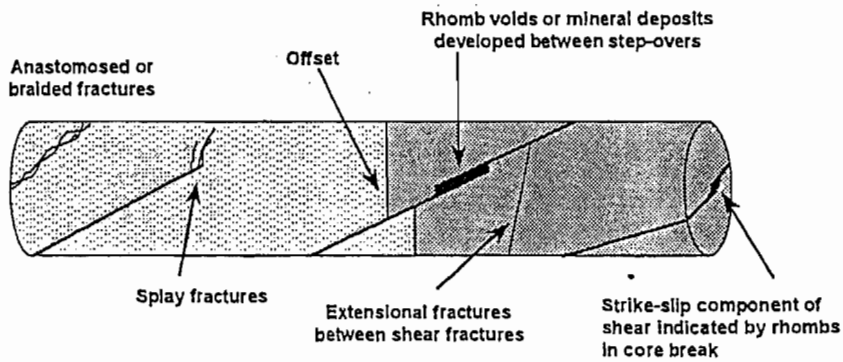


Table Rock Field: Natural Fracture Characterization

The Govt. Union #4 core was examined and types of fractures identified include:

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

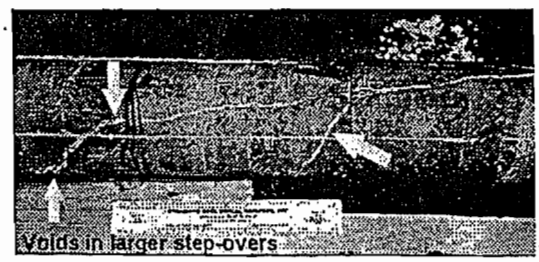


Table Rock Field: Natural Fracture Characterization

17 miles East of the Govt. Union #4, Amoco's Frewen Deep #4 cored and tested the Frontier Fm. Results were poor and the well was abandoned.

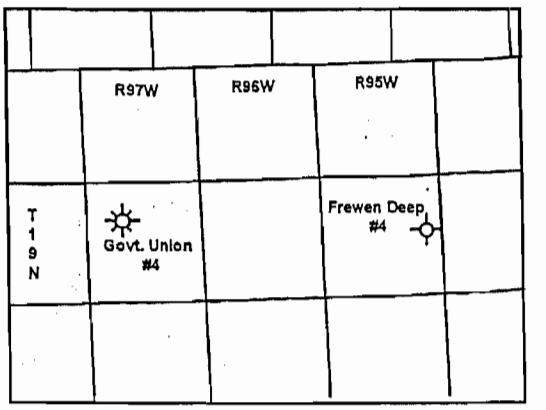
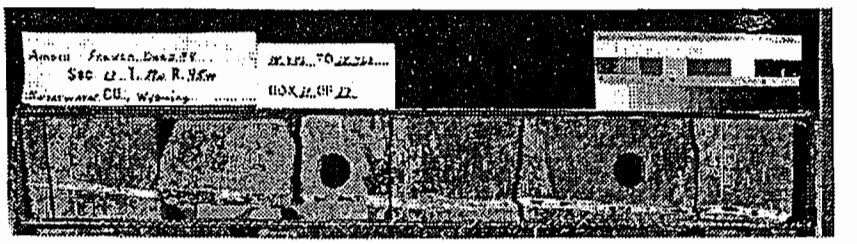


Table Rock Field: Natural Fracture Characterization

The fractures reported in Frewen Deep #4 core (Lorenz and Billingsley, 1996) include:

- Mineralized natural fractures (quartz and calcite) with large isolated apertures .
- "Irregular anastamosed fracture strands."
- Bitumen-filled splay fractures.



Open vertical fractures system propped by quartz pillars.

Table Rock Field: Natural Fracture Summary

- The natural fractures in Govt. Union #4 are dominantly oblique-reverse sheared fractures with an extensional component.
- The natural fractures in Frewen Deep #4 are dominantly extensional.
- Open voids represent storage for gas whereas the sheared fractures provide the deliverability (i.e., the controlling factor in permeability).

Table Rock Field: 3-D Seismic Surveys

Analysis objectives:

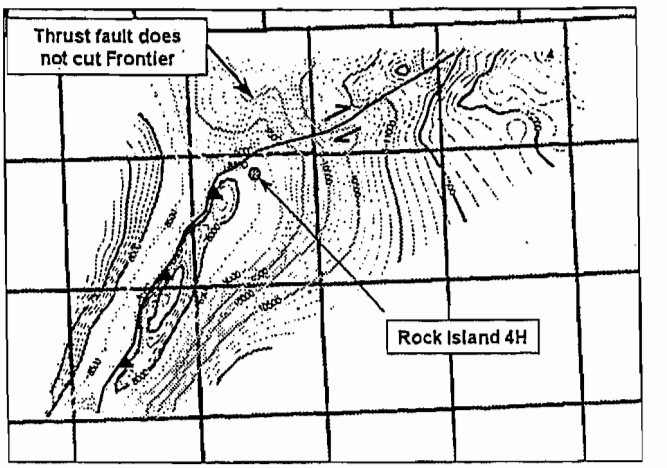
1) To examine history of deformation associated with fault systems and,
2) To provide accurate fault geometry in spatial coordinates for use in stress model.

Selected portions of the Table Rock and Continental Divide Phase II 3D surveys at were post-stack depth converted for mapping.

Table Rock Field: 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.



Subsea structure of the Frontier Fm.

Table Rock Field: Fault Mapping

<u>Summary</u>

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

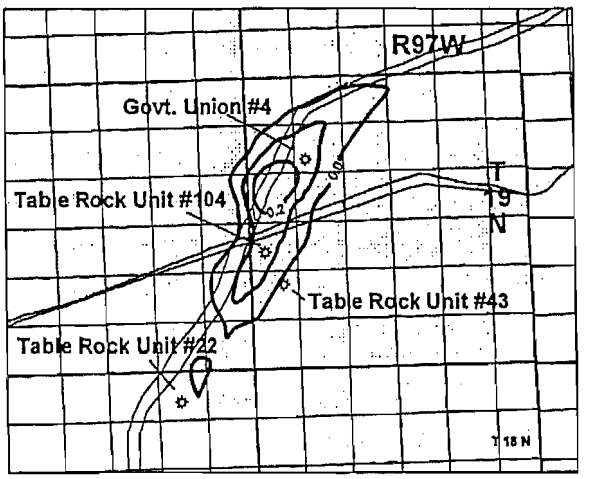
The accommodation occurred on a pre-existing basement shear zone causing the strike-slip tear to be slightly oblique to the thrust fault.

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.

Table Rock Field: Preliminary Geomechanical Model

Predicted location of shear fractures is consistent with successful production from the Frontier and indicates the control of fault-related natural fractures.

This does not mean, however, that the region of mapped natural fractures is a single, connected reservoir.



Normalized Coulomb Stress Map

Contour Interval = 0.05

Table Rock Field: Summary of Geomechanical Model

- The area of mapped fault-related natural fractures correlate with production:
  - Inside the area, the Govt. Union #4 produces 6,000 mcfd and the Table Rock #104 IP'd at 4,300 mcfd (currently produces at 300 mcfd).
  - Outside the area, the initial tests of Table Rock Units #22 and #43 were discouraging and the wells are shut-in at the Frontier interval.
- The Rock Island 4H location is at the northeastern extent of the stress concentration.
- Predicted shear fracture orientations are N27W and N87W.

Detailed Structural Analysis

The geomechanical approach was then tested to investigate a more local scale, appropriate for prospect delineation.

A local area of study around Rock Island 4H was performed after drilling and included:

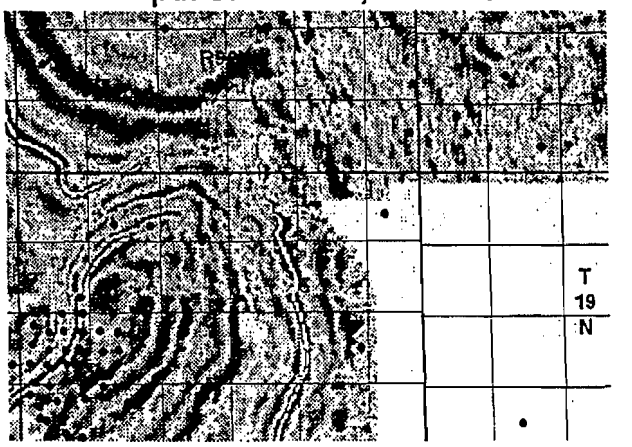
- Depth-migrate the entire 3-D seismic data volume for better definition of structure.
- Map all small faults using coherency filter to enhance identification.
- Rerun stress model to capture small perturbations and identify local areas of shear fracture occurrence that may impact of offset well location(s).

Table Rock Field: Detailed Fault Mapping

- A full 3D data set was extracted around the horizontal drilling location to map the local fault geometry.
  - Depth-converted to map faults in space rather than time.
  - Used coherency processing to optimize fault identification.
- Local geometry of fault systems permit the prediction of local natural fracture development.

Table Rock Field: 3D Seismic Depth Slice 16,000'

Depth Slice at 16,000 feet.



Frontier horizon shown in yellow.

Table Rock Field: Detailed Fault Mapping

Subtle faults and complex geometry of the main thrust and strike-slip system are revealed after coherency filtering.

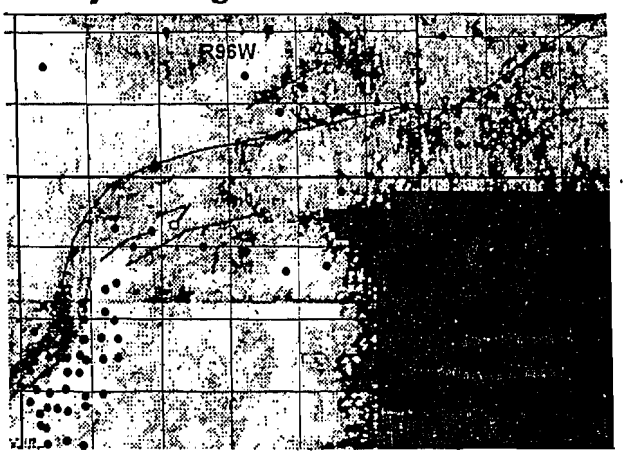


Table Rock Field: Geomechanical Model Results

The Rock Island 4H occupies an area between two small faults and may have hit a zone of enhanced stress concentration.

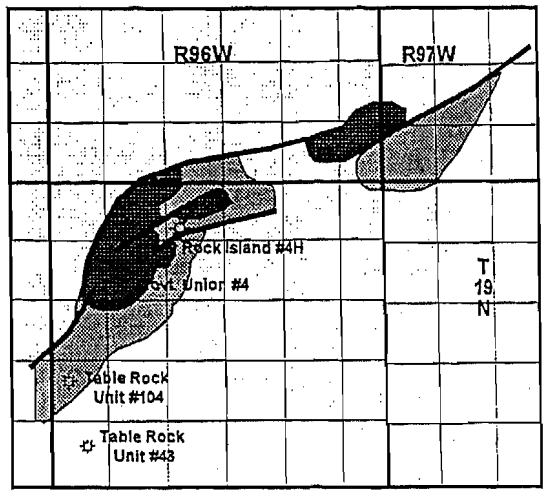


Table Rock Field: Summary of Prospect Delineation

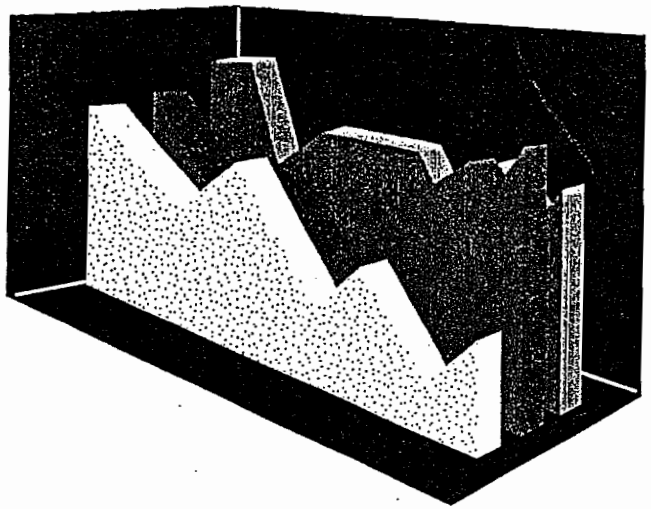
- Detailed analysis of 3D data, aided by coherency processing, reveals a complex fault geometry:
  - small northeast-trending faults in the vicinity of Table Rock horizontal well.
- Geomechanical modelling this more complex system indicates a more diverse and expanded potential for naturally fractured "sweet spots"

Conclusions

- The geomechanical approach provides the means to map fault-related natural fracture clusters that control a reservoir's highly productive "sweet-spot."
- Method is scientifically rigorous and utilizes standard seismic data and borehole information.
- Method is "stand-alone," though may be used in conjunction with other natural fracture detection techniques:
  - Corroborate seismic anomalies such as azimuthal P-wave methods
  - Extend regions of natural fractures detected by 2D shear methods.

Appendix C

Comparative Analysis of the Stratos Federal No. 1 Well



Comparative Analysis of the Stratos Federal No. 1 and Offset Wells

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Outline

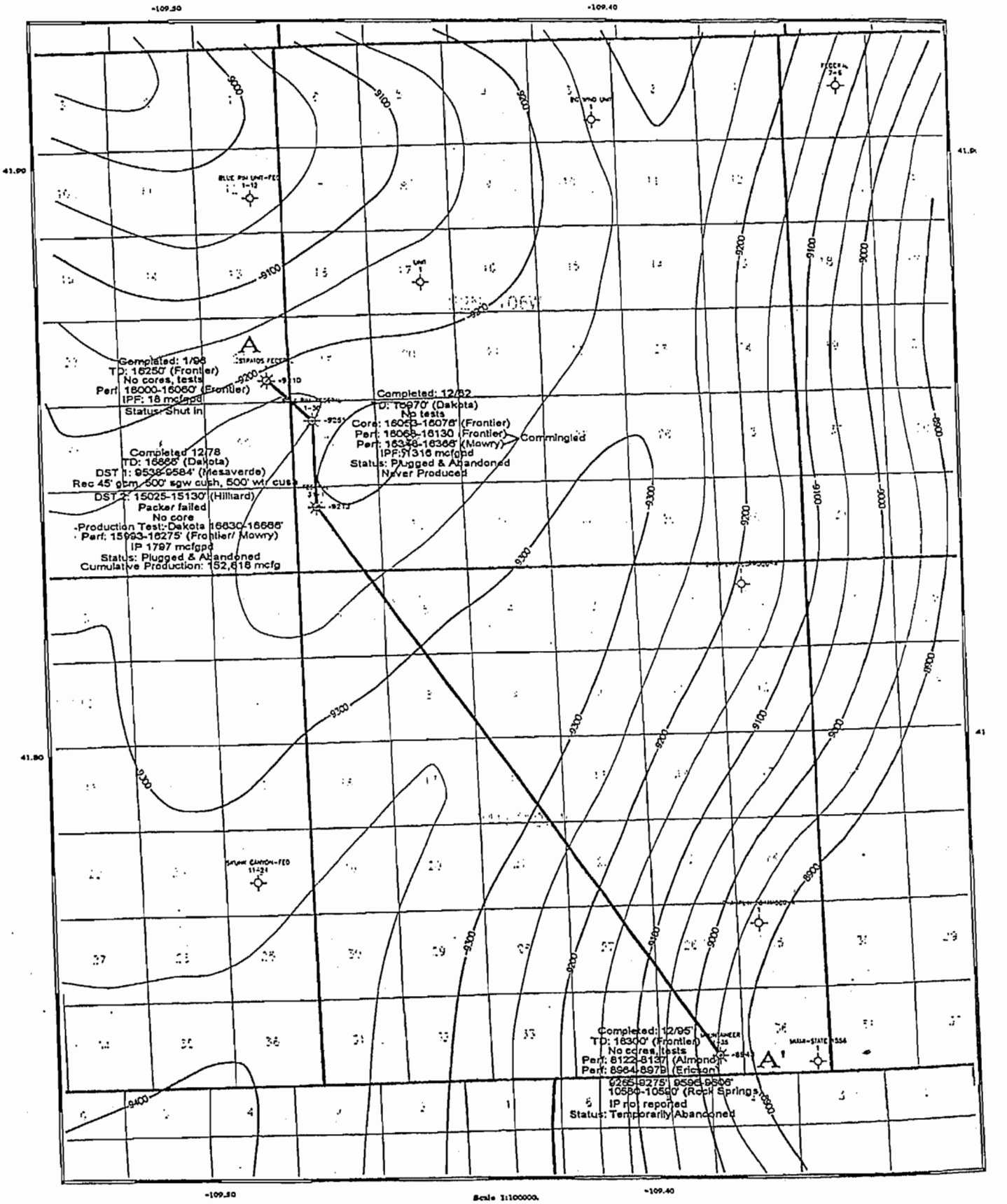
The Comparative Analysis of the Stratos Federal No. 1 and the offset Blue Rim wells contains:

1. *Background/Well Histories*
2. *Structural and Natural Fracture Analysis*
   - *Imagery*
   - *Core Analyses*
   - *Log Analyses*
3. *Deposition, Net Pay and Reservoir Properties*
4. *Completion Procedures*
5. *Assessment of Performance*

Background: Comparative Analysis

Well History #1. The Blue Rim Federal No. 31-1, drilled in 1978, was the first of the Frontier Formation tests in the Stratos area.

- Original objective was a potential structured-stratigraphic trap in the Ericson (Mesaverde) Sandstone.
- When the the Ericson proved disappointing, the well was deepened to test the Frontier and Muddy/Dakota Formations:
  - Gas rate (Frontier) of 100 to 110 Mcfd after perforation
  - Gas rate of 817 Mcfd after acid and KCl water breakdown
  - The sf1 marine interval in the Second Frontier had the best pressure response after perforation and took the largest amount of breakdown fluid.



n

Structure Map
Top 2nd Frontier Marker
Contour Interval: 50 feet

Background: Comparative Analysis

Well History #1. (Continued)

The well was hydraulically stimulated with 81,000 gal gel and 77,000# proppant and completed on December, 1978 as a dual Frontier and Mowry natural gas well:

- *Second Frontier at 15,993' to 16,039'*
- *Upper Mowry at 16,263' to 16,275'*
- *IP of 1,797 Mcfd after hydraulic stimulation*

The well was shut-in until July, 1983 when it was again tested (prior to being TA'd.):

- *The SITP at the start of the test was 12,400 psi (est. reservoir pressure 12,880 psi with a gradient of 0.80 psi/ft.)*
- *A six day flow test had rates of 1,500 to 3,733 Mcfd*
- *A perforating gun, two packers and tail pipes well lost in the hole ("fish")*

Background: Comparative Analysis

Well History #1. (Continued)

- The Blue Rim 31-1 well was placed on production in January, 1996 after being hooked to a surface pipeline:
  - The "fish" was pushed to 16,228', covering the Mowry perforations.
  - The well began producing at 615 Mcfd and reached gas rates of 800+ Mcfd in the second month.
  - The well ultimately produced 150 MMcf before experiencing a downhole tubing failure; it was P&A'd in December, 1987.

- The well experienced production problems throughout its life, producing drilling mud and frac fluid, intermittently plugging off gas flow.

Background: Comparative Analysis

Well History #2. The Blue Rim Federal No. 1-30 well, drilled in 1982, is the offset to the Blue Rim Federal No. 31-1 Megan Field discovery well:

- The well, drilled to fulfill a contractural obligation, reached a TD of 16,969' in the Dakota Formation:
  - *The well was perforated from 16,068' to 16,130' in the Frontier and from 16,348' to 16,356' in the upper Mowry.*
  - *Three cores were cut in the Frontier, from 16,053' to 16,707'.*
  - *The well required extremely high mud weights, up to 14.4 ppg.*
- After perforating the Frontier and Mowry, the well blew out and the extreme pressure collapsed the liner and tubing. After containment:
  - *The surface shut-in pressure was 6,000 to 7,000 psi.*
  - *In a nine hour test, the well flowed at 1,316 Mcfd plus 72 B/D of load water.*

Background: Comparative Analysis

Well History #2. (Continued):

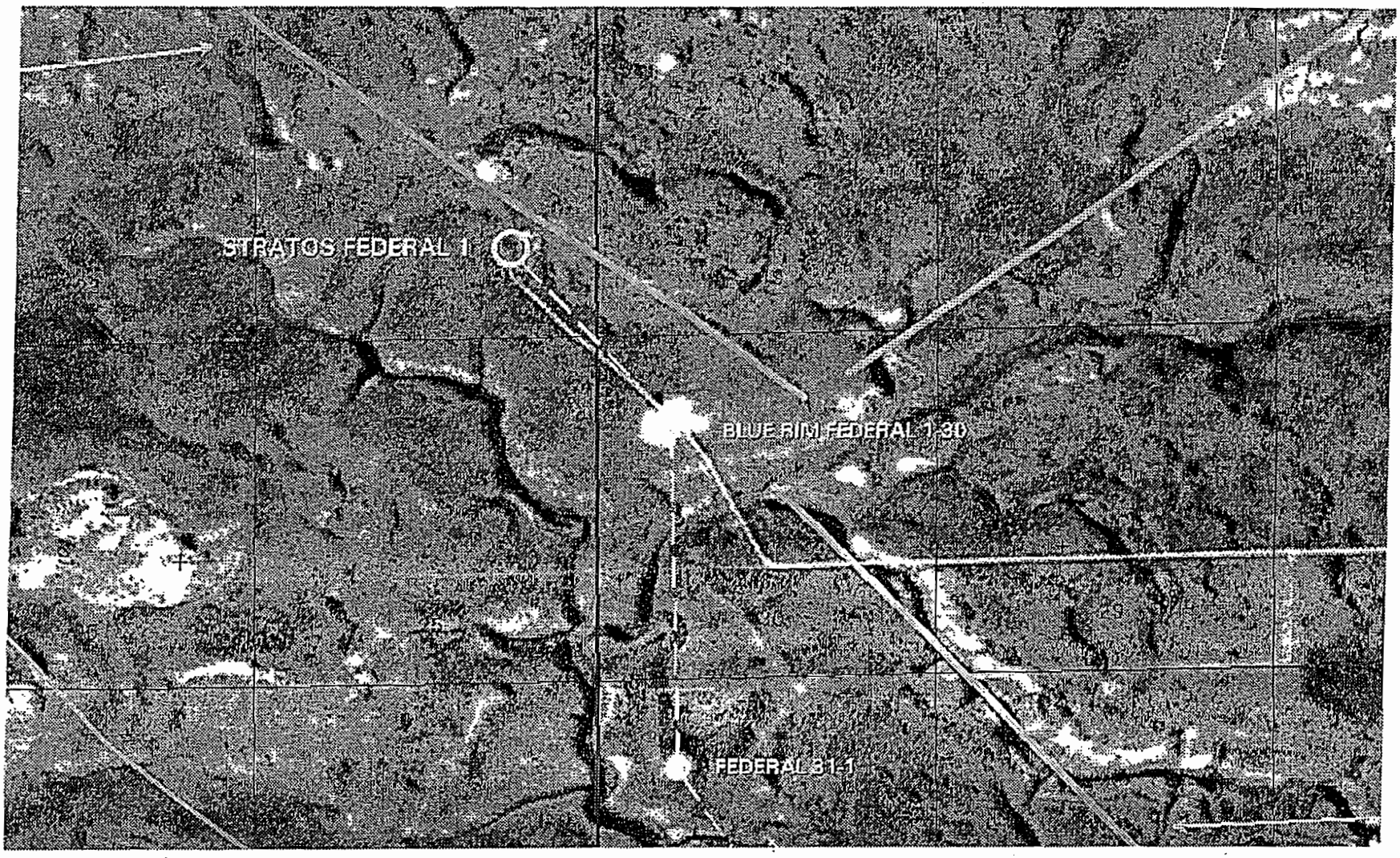
- Uncertainty exists as to the completion, stimulation and further testing of the well:
  - *State records indicate a hydraulic fracture treatment of 2,524 bbls of gel and 150,000 pounds of proppant.*
  - *The onsite completion supervisor and engineer stated that, although a frac was planned, the damage to the well was too severe and prevented further completion or stimulation.*
- After three months of fishing and attempted repairs, the well was shut-in in December, 1982 and P&A'd in November, 1989.

Detailed Imagery Analysis

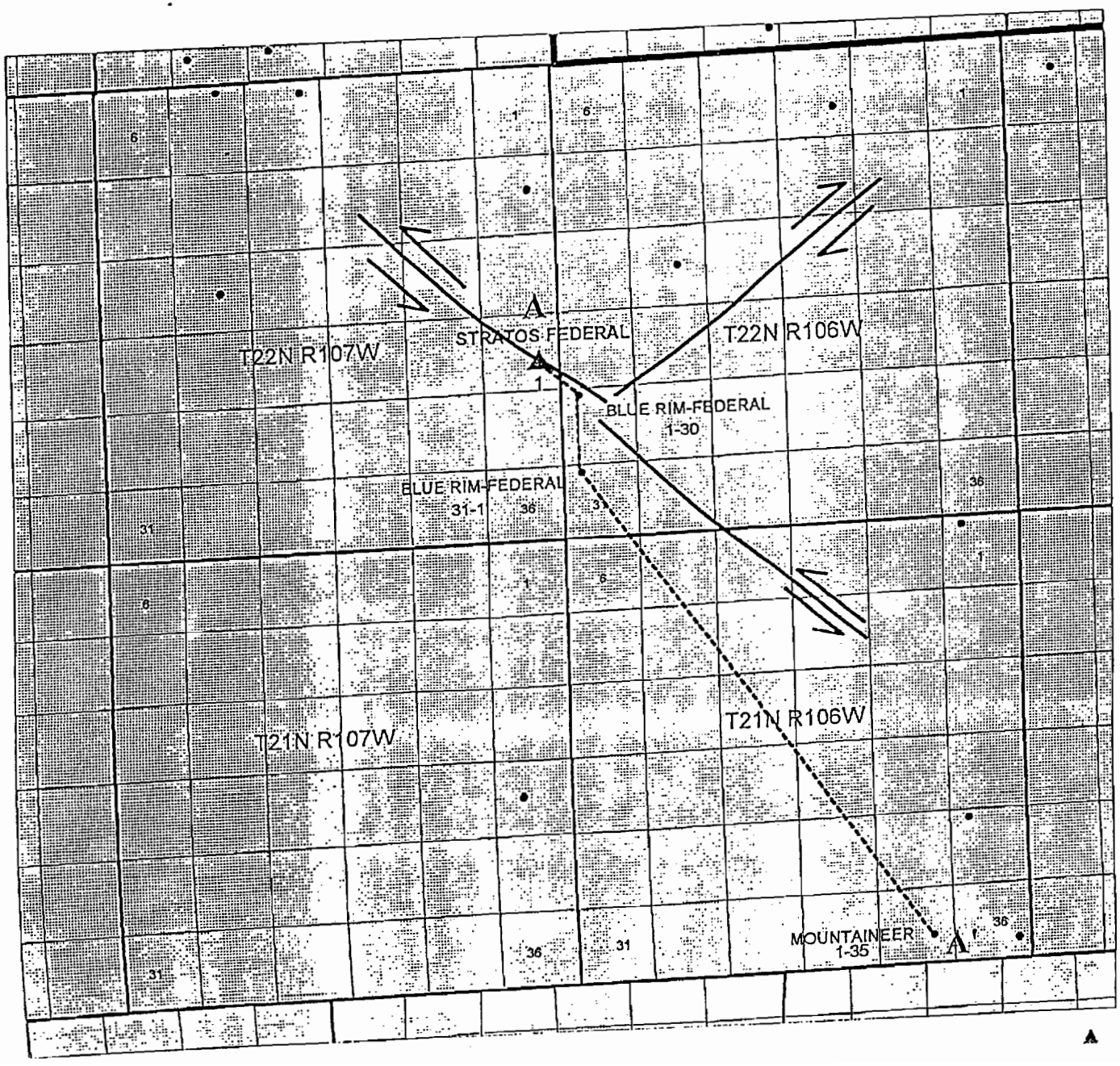
High-resolution (5m) IRS-1C satellite imagery was digitally merged with Landsat TM imagery for detailed photogeologic analysis of the Stratos area (1:24K)

- *Possible near-surface faults were identified, with sense of motion inferred from direct analogy with Table Rock and from local topographic features (escarpments, drainage patterns).*
- *All faults appear to have small offset, and may not extend far into subsurface; field observations combined with high-resolution aeromagnetic and 3-D seismic data are required to reliably define the fault geometries at Frontier level.*
- *Stratos site is crossed by two NW-trending left-lateral shear or wrench faults, offset by a NE-trending right-lateral fault.*
- *Stratos well site is in compressional quadrant of northern left-lateral fault; Blue Rim 31-1 is in tensional quadrant of southern fault, and Blue Rim 1-30 is near complex intersection of three faults.*

Detailed Surface Analysis:
Surface fault pattern overlain on merged Landsat/IRS imagery



Green River Deep - Stratos Study Area Faults

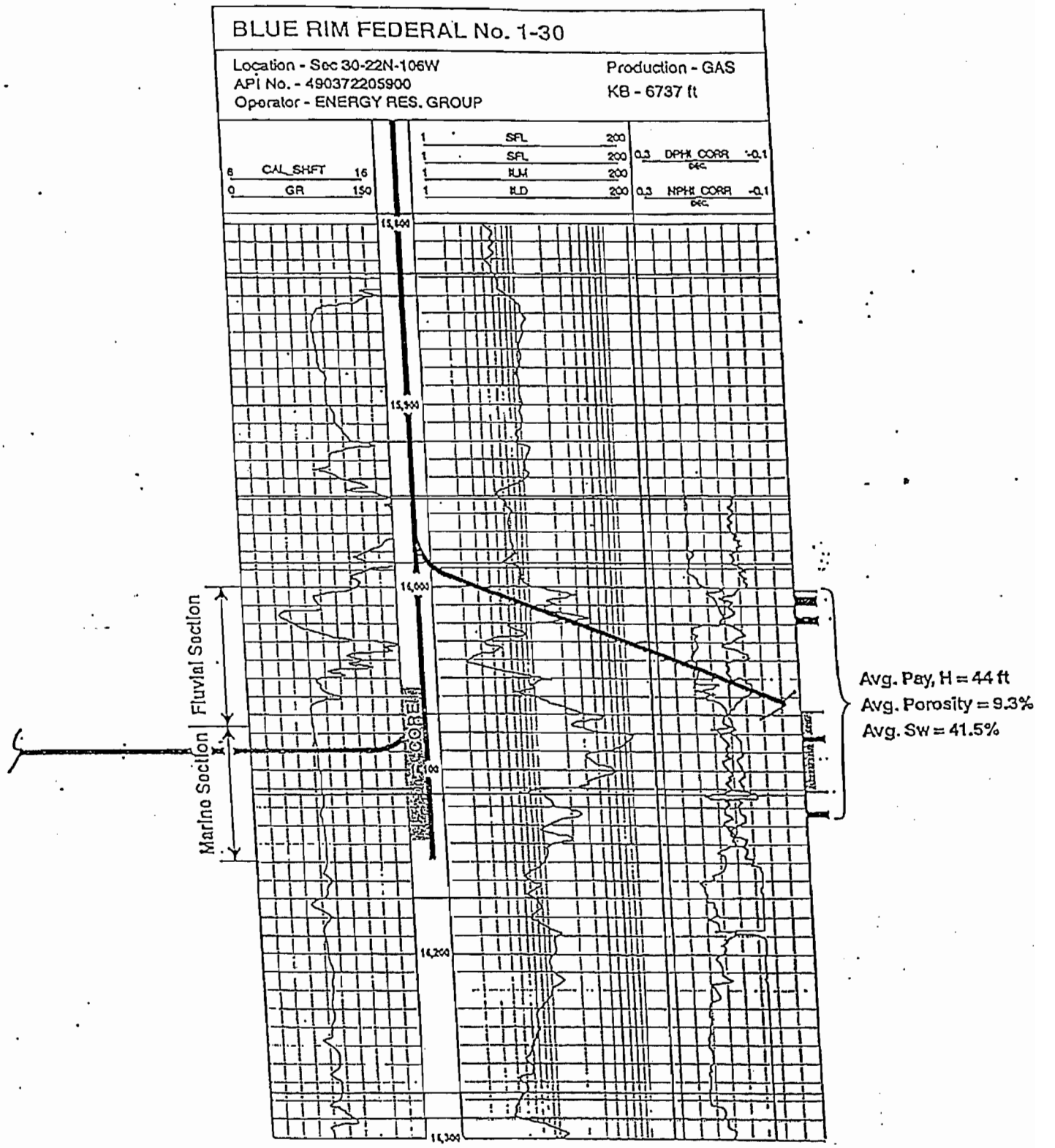


Inference of Natural Fractures

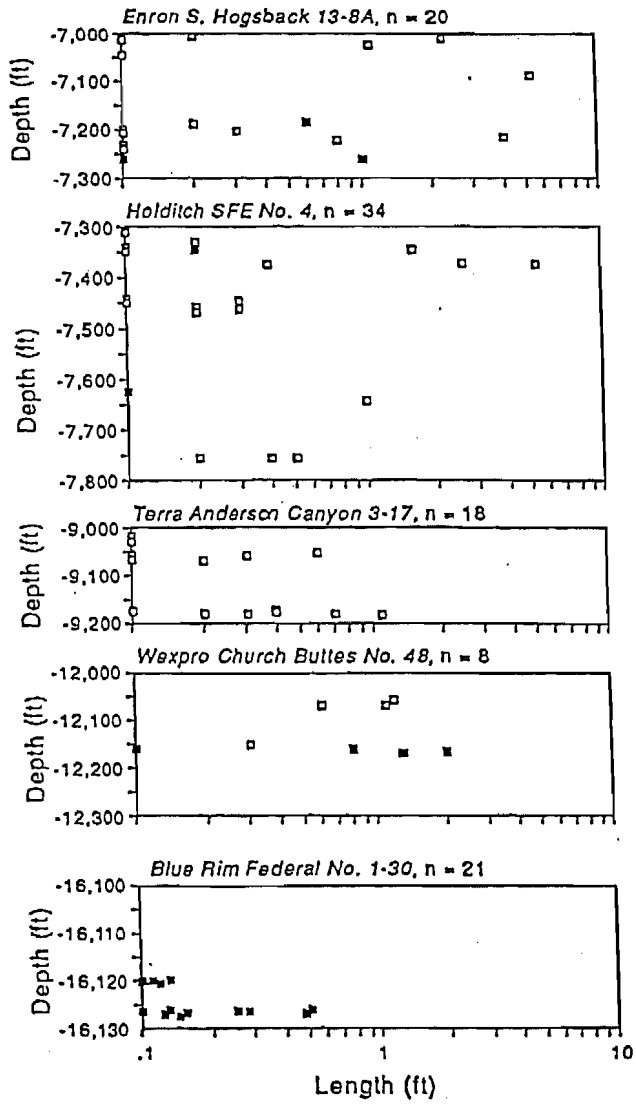
The presence and importance of natural fractures in the Frontier formation in the Stratos well area is based on the following observations:

- BEG identified a series of natural fractures in the Blue Rim Federal 1-30 well, as shown on the attached figures.
  - *The fractures are extentional and calcite filled*
  - *The fractures occur in one interlaminated sandstone and mudstone interval at 16,120 to 16,130 feet*
  - *The fractures have heights of 6 inches, widths of up to 0.25 mm, and spacing of 0.4 to 1.2 inches.*
- The core analysis for the Blue Rim Federal 1-30 well (by Terra Tek) indicates improved permeability at 16,101'-16,102' (0.10 md) 16,122'-16,123' (0.31 md), although Terra Tek attributes this to horizontal dehydration cracks.

Second Frontier Log from Offset Well with Test Well Schematic



Fractures in Core from Five Frontier Fluvial Wells in the Green River Basin (Laubach, 1991)

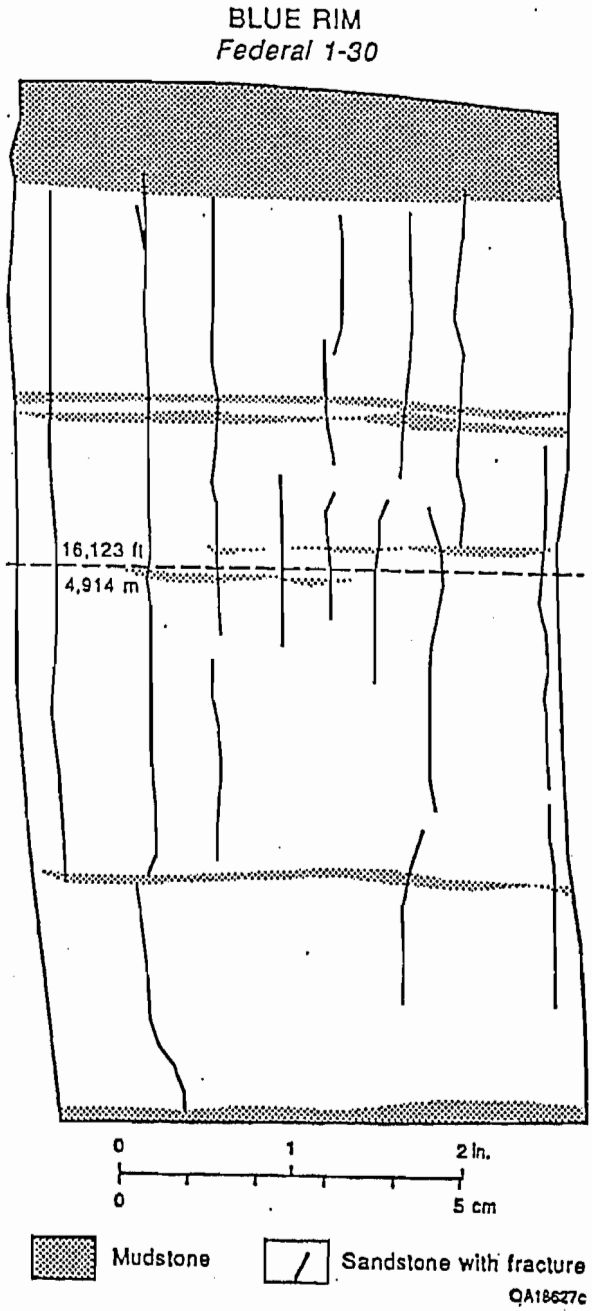


□ Small fault or shale fracture
▪ Extension fracture in sandstone

QA15574c

Closely Spaced Vertical Fractures in Frontier Formation Core, Blue Rim Federal No. 1-30 Well

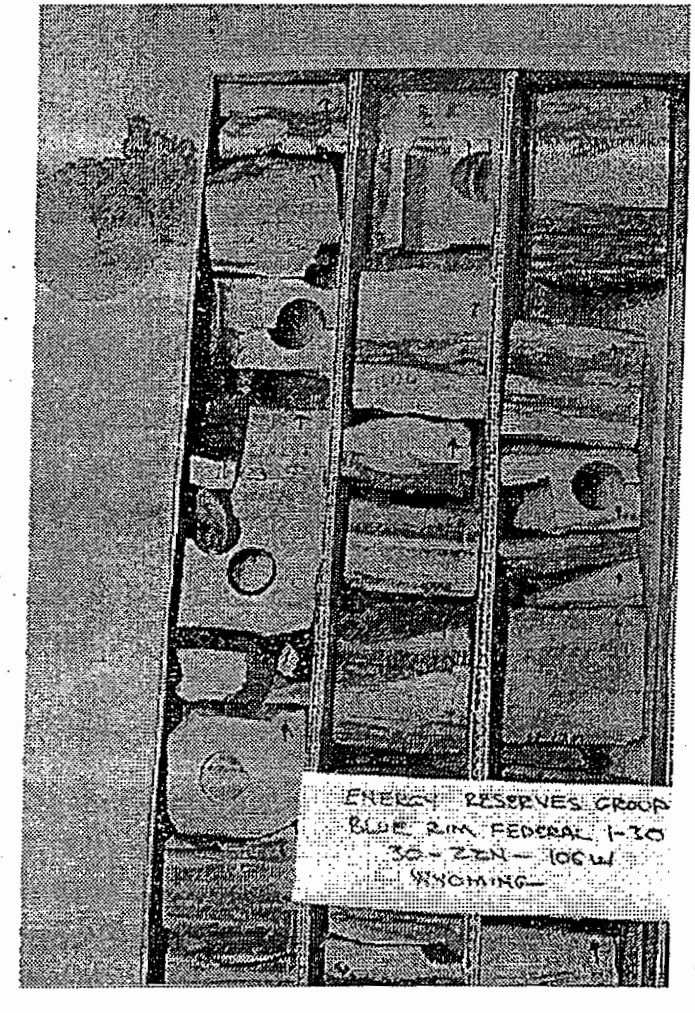
Core Depth 16,123 ft (4,914 m)



Stratos Area: Core Observations

Core taken from Blue Rim Federal 1-30 well.

Abundant horizontal parting, little vertical fracturing apparent.



Inference of Natural Fractures

Overall, the Stratos core shows poor natural fracture development. The routine, unstressed core analysis on the Stratos well (by Terra Tek) identified a series of partly open natural fractures, as follows:

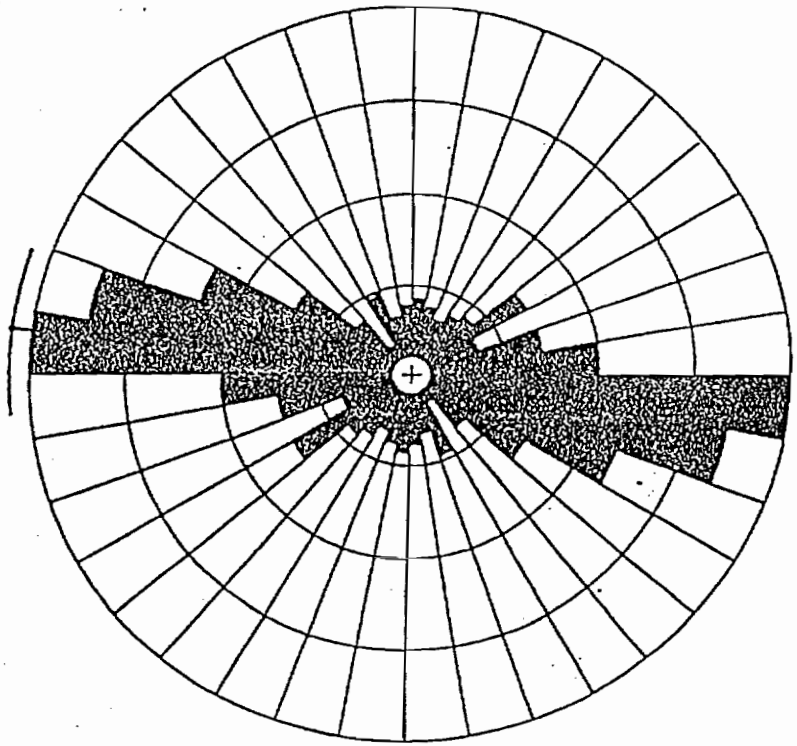
- *16,004-16,019': Small (1 to 2") vertical fractures within thin sandy beds*
- *16,041': Subvertical fractures filled with black material*
- *16,065': Open with calcite, other fractures with block fill*

However, when the core and log depths are made consistent, the small vertical fractures at 16,004 to 16,019' are in an interval above the upper pay zone. Terra Tek notes that the direction of maximum stress (N65E) agrees with several fractures in core.

Rose Diagram Showing the Strike

Measured Microfractures from 16,027 Feet

(Note that the area of thin section studied is less than 1% of total thin section



ST16027C-- all fracs, both areas 7/10	Statistics
N = 255	Vector Mean = 277.0
Class Interval = 10 degrees	Conf. Angle = 12.65
Maximum Percentage = 16.5	R Magnitude = 0.376
Mean Percentage = 5.56 Standard Deviation = 4.07	Rayleigh = 0.0000

Stratos Log Analysis

Schlumberger applied a very detailed logging package to the Stratos No. 1 well, including a standard logging suite and a series of new, "high tech" logs.

- *The standard set of wireline logs included Resistivity (shallow and deep Laterlog), Litho-Density, Neutron, Gamma Ray and Caliper.*
- *"High tech" logs included Formation Micro Imager (FMI), Azimuthal Resistivity Imager (ARI), Diapole Sonic Imager (DSI), and several others.*

Based on the interpretation of these logs, Schlumberger concluded the following:

- *The APS (Accelerator Porosity Sounder for porosity at depth of invasion) " points towards poor filtrate invasion and less than optimum conditions for permeability".*
- *The FMI, "confirms the ARI interpretation of no fractures, low dips, and many thin beds."*
- *From the ARI "we can infer the lack of natural fractures".*

Stratos Log Analysis

- *The CMR (Combinable Magnetic Resonance) indicates the "producible water, which while not zero, is only about 2% of the rock's total volume," "very tight gas sands," and "an in situ permeability of 0.073 md-ft."*

- *From the DSI, Schlumberger observes "The maximum horizontal stress is greater than the overburden stress," and "high minimum horizontal stress ... or a lack of a strong principle stress direction." The DSI also showed "lack of anisotropy" that "may explain the paucity of natural fractures."*

Schlumberger concluded that "the environment (around the Stratos No. 1 well) is not conducive to natural fractures" and that the lack of fractures has "been verified by the ARI, FMI, and DSI" tools.

Log Inventory

STRATOS FEDERAL UNIT #1 12-1/4" Hole with 11.7 lb/gal Water based Mud			
OPEN HOLE LOGS	RUN 1 10/13/95	DSI (Dipole Shear Sonic Imager)	16231-15700'
		DSI (Dipole Shear Sonic Imager)	11281-7900'
		LLD (Laterolog Deep)	16141-5020'
		LLS (Laterolog Shallow)	16141-5020'
		SP (Spontaneous Potential)	16141-5020'
		GR (Gamma Ray)	16141-5020'
		Caliper	16141-5020'
		ARI (Azimuthal Resistivity Imager)	16141-5020'
	RUN 2 10/14/95	LDS (Litho-Density Sonde)	16141-5015'
		APS (Accelerated Porosity Sonde)	16141-5015'
		HNGS (Natural Gamma Ray Spectroscopy)	16141-5015'
	RUN 3 10/14-15/95	CMR (Combination Magnetic Resisitivity Tool)	16141-5020'
		CMR (Combination Magnetic Resisitivity Tool)	11150-7950'
		CNL (Compensated Neutron Log)	16141-5015'
		GR (Gamma Ray)	16141-5015'
	RUN 4 10/17/95	FMI (Formation MicroScanner Imager)	16150-15500'
		FMI (Formation MicroScanner Imager)	11100-7950'
		GR (Gamma Ray)	16150-15500'
		GR (Gamma Ray)	11100-7950'
CASED HOLE LOGS		CBL (Cement Bond Log)	16189-12000'
		Velocity Shots (every 50')	16150-500'
OTHER LOGS		MWD (Measurement While Drilling) Caliper	13870-16250'
		MWD (Measurement While Drilling) GR	13870-16250'
		Mud Log	7000-16250'

Deposition and Net Pay

In general, the deposition and sand development of the Second Frontier Formation in the four townships surrounding the Stratos well are favorable and representative of the Green River Deep Partition:

- *The net sand in the Stratos well, for the combined fluvial and marine intervals, is 30 feet (using 6% porosity and 50 Gamma Ray cutoffs).*
  - *The fluvial sand, at 3 feet, is less developed, compared to 5 to 10 feet in the area.*
  - *The marine sand, at 27 feet, is representative of the NE/SW trend of marine deposition in the area.*
- *The Stratos well porosity, at 7.6%, is slightly lower than the 8% porosity for the area.*
- *The Stratos well reservoir pressure, at 12,000+ psi, is highly overpressured, as is the Frontier in the offset wells.*

Deposition and Net Pay

Methodology. Selected well log traces from the Stratos No. 1, Blue Rim No. 1-30, Blue Rim No. 31-1, and Mountaineer No. 1-35 wells were digitized for construction of the cross-section.

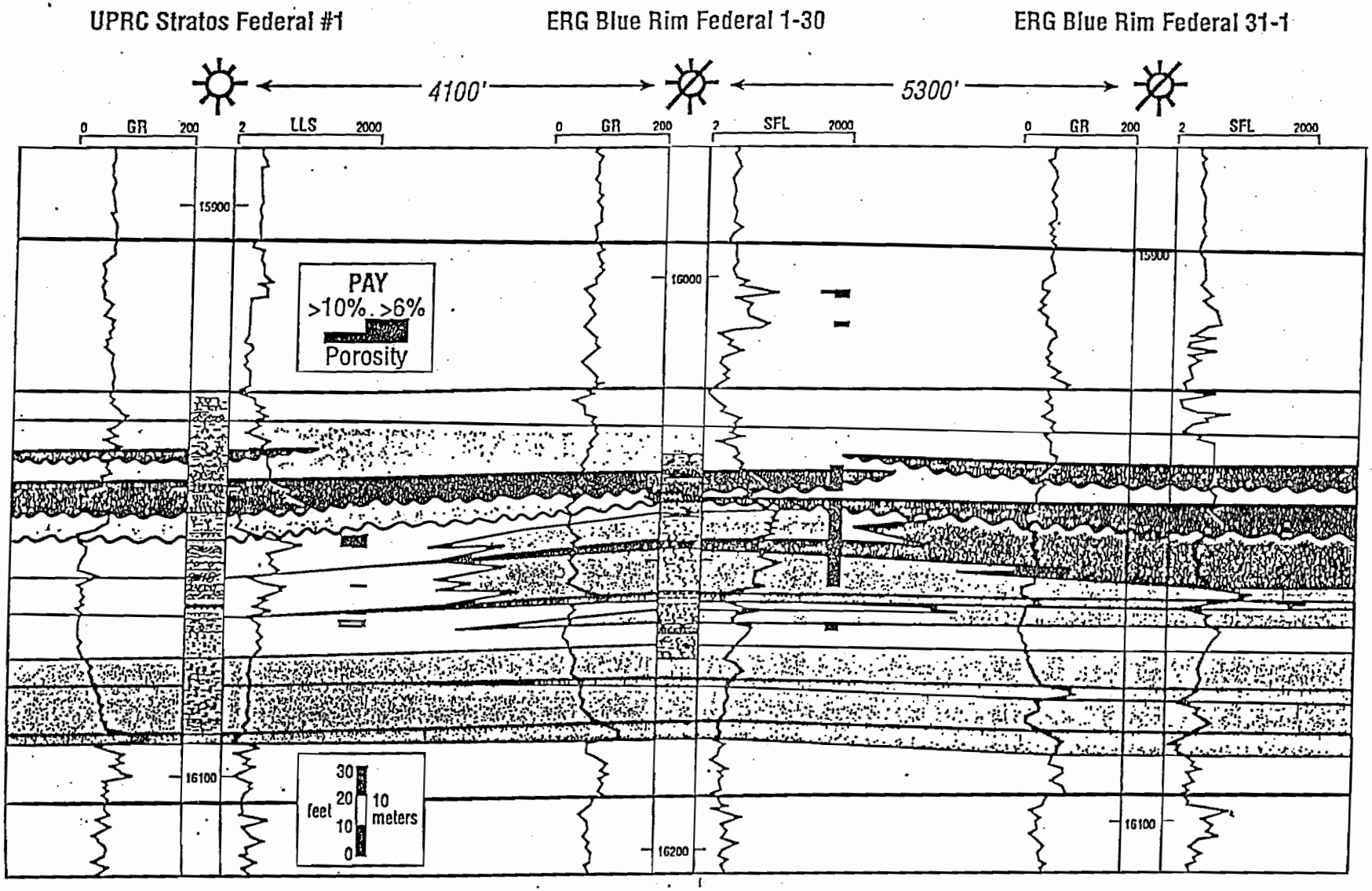
The cross-section utilizes the gamma ray and Neutron-Density porosity log curves recorded in each well. Detailed log correlations of the 2nd Frontier and upper Mowry were coupled with core descriptions in the Stratos No. 1 and Blue Rim No. 1-30 to constrain correlation markers. Drill cutting descriptions from the Blue Rim No. 1-30 were also useful.

Stratigraphic Correlation and Reservoir Description

The UPRC Stratos No. 1 well is located near the axis of the Green River Basin, where it crosses the east plunge of the Sandy Bend anticline. Offsetting the Stratos No. 1 well (0.7 miles and 1.6 miles to the southeast) are the Blue Rim No. 1-30 and the Blue Rim No. 31-1 wells respectively.

Located 9.5 miles further to the southeast is the Mountaineer No. 1-35 well.

Stratigraphic Cross Section for the Stratos #1-24 and the Two Blue Rim Wells



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Cross-Section

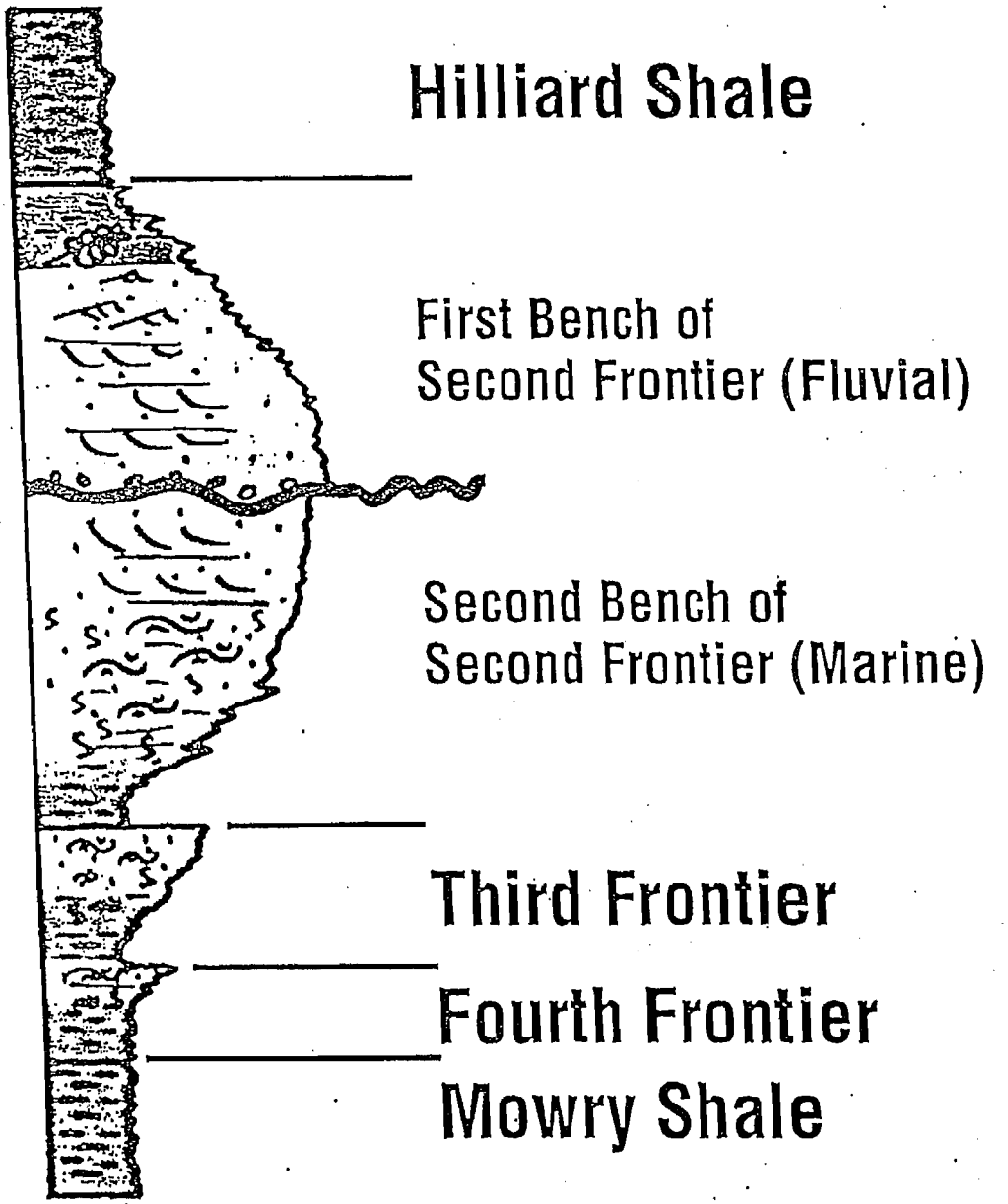
(See Large Scale
Cross Section on Wall)

Deposition and Net Pay

Frontier Formation. The Frontier Formation is approximately 310 feet thick in the Stratos well area. The 2nd Frontier interval straddles the mid-Turonian unconformity. The top of the 2nd Frontier interval was selected on a resistivity marker that occurs at a depth of 15,900 feet in the Blue Rim No. 31-1 well.

The Upper 2nd Frontier member typically contains fluvial to estaurine sandstone reservoirs at its base. Below the mid-Turonian unconformity, the 2nd Frontier member is dominated by marine shoreface sandstone reservoirs. Regionally these sandstone reservoirs are truncated resulting in large differences in thickness across the basin.

Schematic Vertical Profile of the Second Frontier Formation, Green River Basin, Wyoming



Deposition and Net Pay

Frontier Formation. Three reservoir intervals are correlated in the 2nd Frontier, as noted on cross-section A-A'. The uppermost pay, is a very thin fluvial sandstone that ranges from 3 to 12 feet of net sandstone with (GR <50 porosity >6%), a mean porosity of 8%.

The 2nd Frontier contains two additional reservoir zones. The sf2 reservoir is the upper zone and has a varaible thickness. The sf2 reservoir is absent in the Mountaineer No. 1-35 well and is thin in the Stratos Federal No. 1 and Federal No. 31-1 wells.

The sf1 reservoir (of the 2nd Frontier) is separated from the sf2 reservoir by a two to four foot thick shale bed that can be correlated in all four wells. The sf1 reservoir has the best lateral continuity and sand development.

Deposition and Net Pay

Mowry Shale. The Mowry Shale is 400 feet thick in the Stratos well area. The top is picked at the base of a prominent shale marker, at 16,212 feet in the Federal No. 31-1 well. About 50 feet below the top of the Mowry shale is a widespread, 12 to 20 foot thick, fine to medium grained glauconitic sandstone, the upper Mowry.

The upper Mowry sandstone is easily correlated and contains 10 to 13 feet of net sandstone (>6% porosity). The sandstone averages 9.35% porosity and accounts for between 20% and 25% of the calculated reservoir pore volume in the 2nd Frontier and Mowry interval.

The upper Mowry sandstone was completed in both the Federal No. 31-1 and the Blue Rim Federal No. 1-30 wells. The upper Mowry sandstone is not penetrated in the Stratos Federal No. 1 and in the Mountaineer No. 1-35 wells.

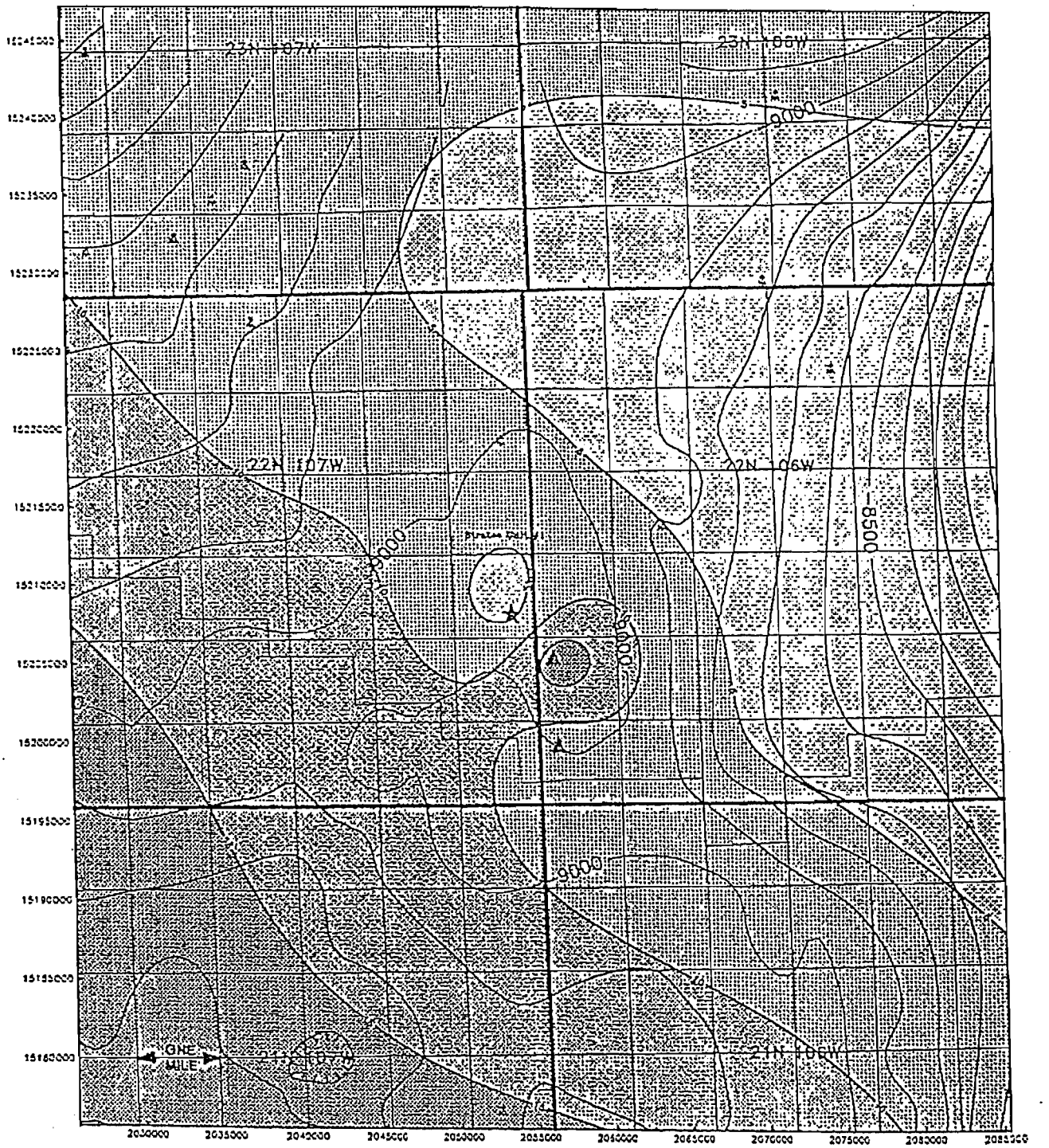
Findings and Conclusions

Three reservoir zones are differentiated in the 2nd Frontier interval; (1) the fluvial reservoir, (2) the sf2 reservoir, and (3) the sf1 reservoir. The reservoir properties of each zone are summarized below:

Well	Gross Sand	Net Sand ≤GR50	Net Sand <6%	ϕ (h)	Mean ϕ	Mcfgpd Post-Brkdn
Stratos Federal No. 1	47.0	33.0	30.0	2.780	.076	18-20
Federal No. 31-1	42.0	33.0	31.0	2.710	.080	690-817
Blue Rim Federal No. 1-30	59.0	57.0	56.0	4.811	.082	378-1316?

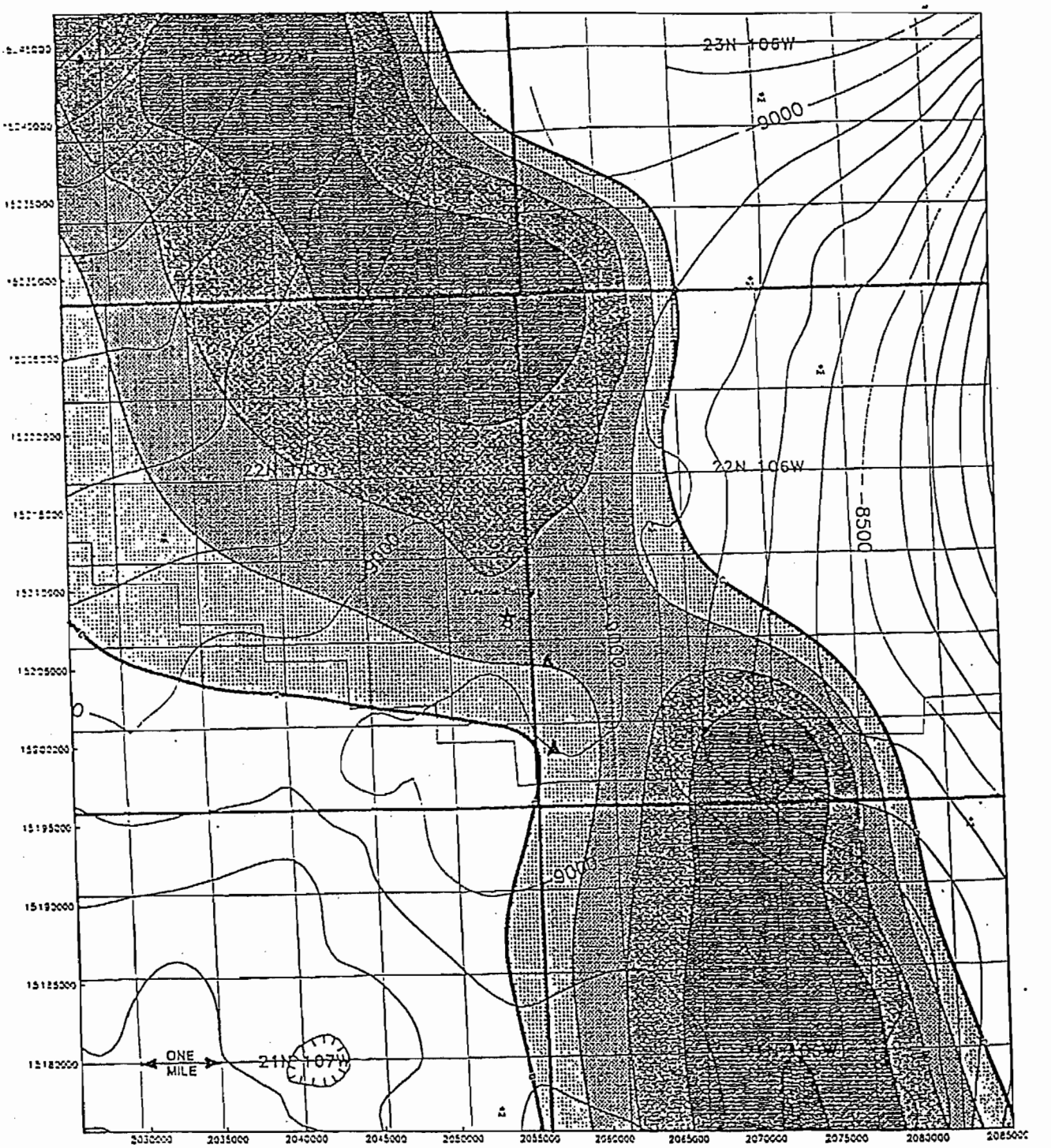
Local Isopach Map of Net Feet of Pay in the Second Frontier Fluvial Interval at the Stratos Location

(Shown as Star) Contour Interval = 5 ft.



Local Isopach Map of Net Feet of Pay in the Second Frontier Marine Interval at the Stratos Location

(Shown as Star) Contour Interval = 10 ft.



Reservoir Properties Stratos Area

Western Greater Green River Basin

'ell/Producing Zone	Log Analysis					Core Analysis			Mean Rwa	Comments
	Gross sand	Net sand < GR 50 API	Net sand >6% phi	phi(h)	mean phi	phi(h)	mean phi	k(h)		
'ederal No.1										
2nd Kf fluvial	6.0	3.0	3.0	0.150	0.070	0.267	0.067	0.610	0.250	
2nd Kf maine: sf2	12.0	10.0	9.0	0.749	0.068	0.740	0.068	0.163	0.120	
2nd Kf marine: sf1	29.0	20.0	18.0	1.881	0.090	1.648	0.078	0.754	0.180	
Upper Mowry sand										not penetrated
Total	47.0	33.0	30.0	2.780	0.076	2.655	0.071	1.527	0.180	
ıeer No.1-35										
2nd Kf fluvial	12.0	10.5	12.0	0.890	0.087	no core	no core	no core	0.130	
2nd Kf maine: sf2	0.0	0.0	0.0	0.000						absent
2nd Kf marine: sf1	38.0	35.5	30.0	2.560	0.095	no core	no core	no core	0.120	
Upper Mowry sand										not penetrated
Total	50.0	46.0	42.0	3.450	0.091				0.125	
ɜr Federal No.1-30										
2nd Kf fluvial	8.0	9.0	9.0	0.858	0.085	0.644	0.064	0.488	0.470	
2nd Kf maine: sf2	31.0	31.0	30.0	2.410	0.075	1.790	0.056	0.670	0.570	
2nd Kf marine: sf1	20.0	17.0	17.0	1.543	0.085	insuf. Data	insuf. Data	insuf. Data	0.180	
Upper Mowry sand	18.0	2.0	13.0	1.203	0.093	no core	no core	no core		
Total	77.0	59.0	69.0	6.014	0.085				0.407	
Vo.31-1										
2nd Kf fluvial	13.0	7.0	8.0	0.780	0.097	no core	no core	no core	0.290	
2nd Kf maine: sf2	8.0	6.0	4.0	0.310	0.061	no core	no core	no core	0.210	
2nd Kf marine: sf1	21.0	20.0	19.0	1.620	0.083	no core	no core	no core	0.150	
Upper Mowry sand	13.0	0.0	10.0	0.949	0.094	no core	no core	no core		
Total	55.0	33.0	41.0	3.659	0.083				0.217	

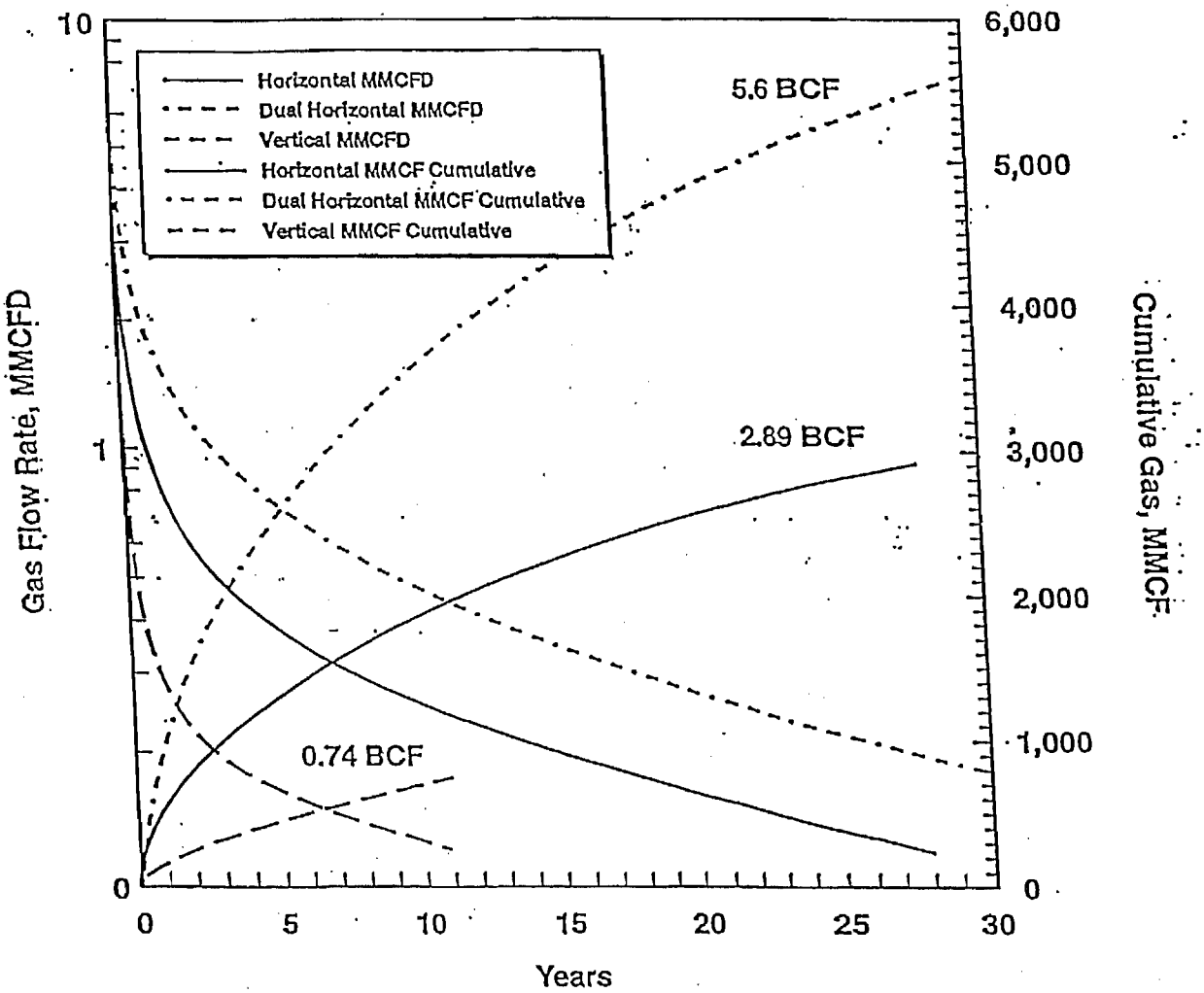
Stratos Well Completion and Testing

The initial plan was to drill a vertical well, test the Frontier, and then drill two long horizontal laterals, based on expectations of 3 to 5+ Bcf of gas recovery.

- *The reservoir permeability and natural fracture development in the Stratos well appeared to be low.*
- *Well tests in the Stratos showed a permeability of about 1 μ d and flows to surface were only about 20 Mcfd, much less than for the Blue Rim wells.*
- *Performance analysis by Schlumberger indicated a maximum flow rate of 45 Mcfd after stimulation.*

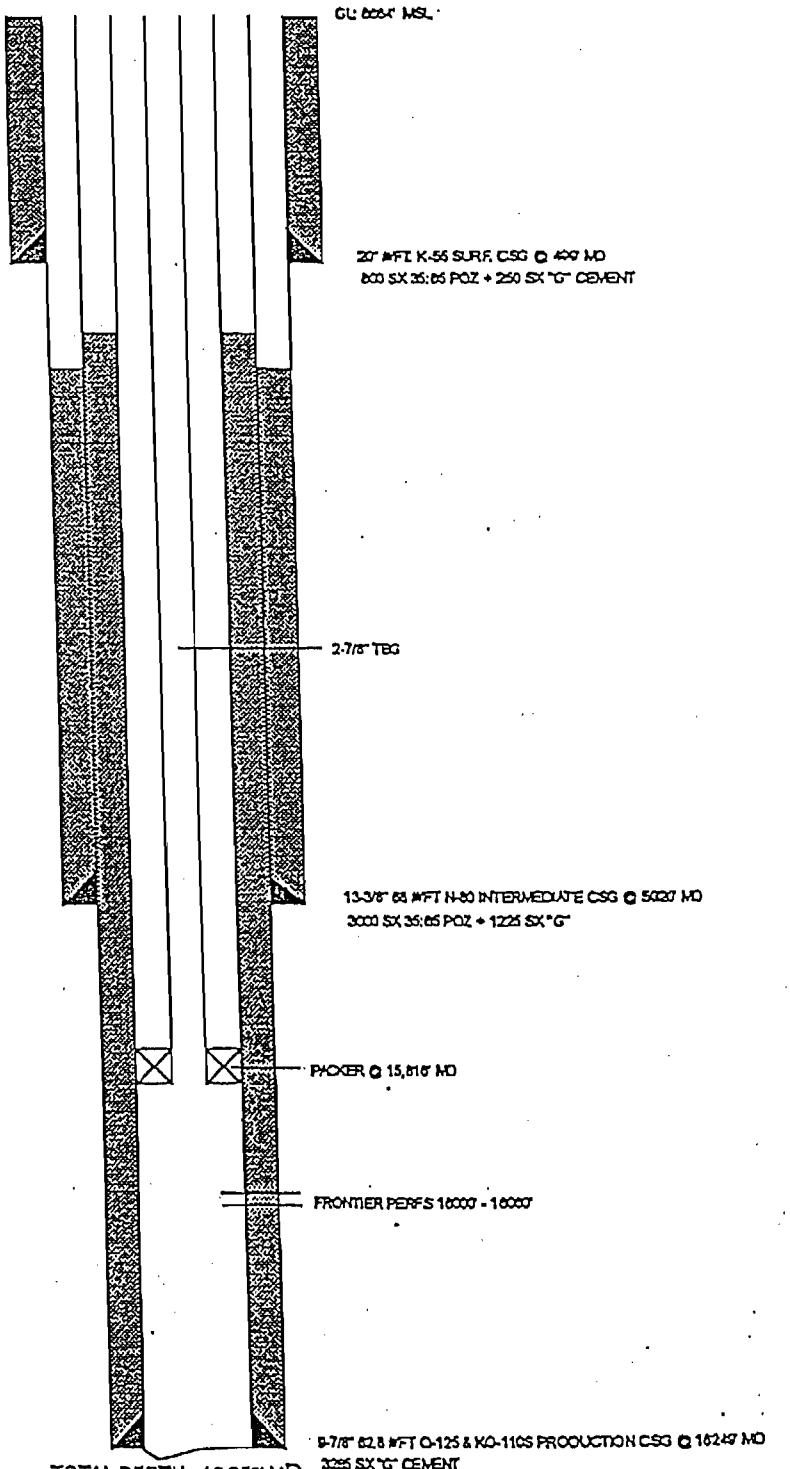
Based on this, activities in the Stratos well were placed on hold.

Model Production Performance and Cumulative Recoveries for the Marine Bench, Second Frontier Formation at the Proposed Site



Wellbore Diagram

WELL NAME: UPR STRATOS FEDERAL UNIT No. 1
SL: SE/4 SEC. 24, T. 22 N., R. 107 W., 6TH PM
B-HL: 1412' FSL, 1273' FEL SEC. 24, T. 22 N., R. 107 W., 6TH PM
SWEETWATER COUNTY, WYOMING



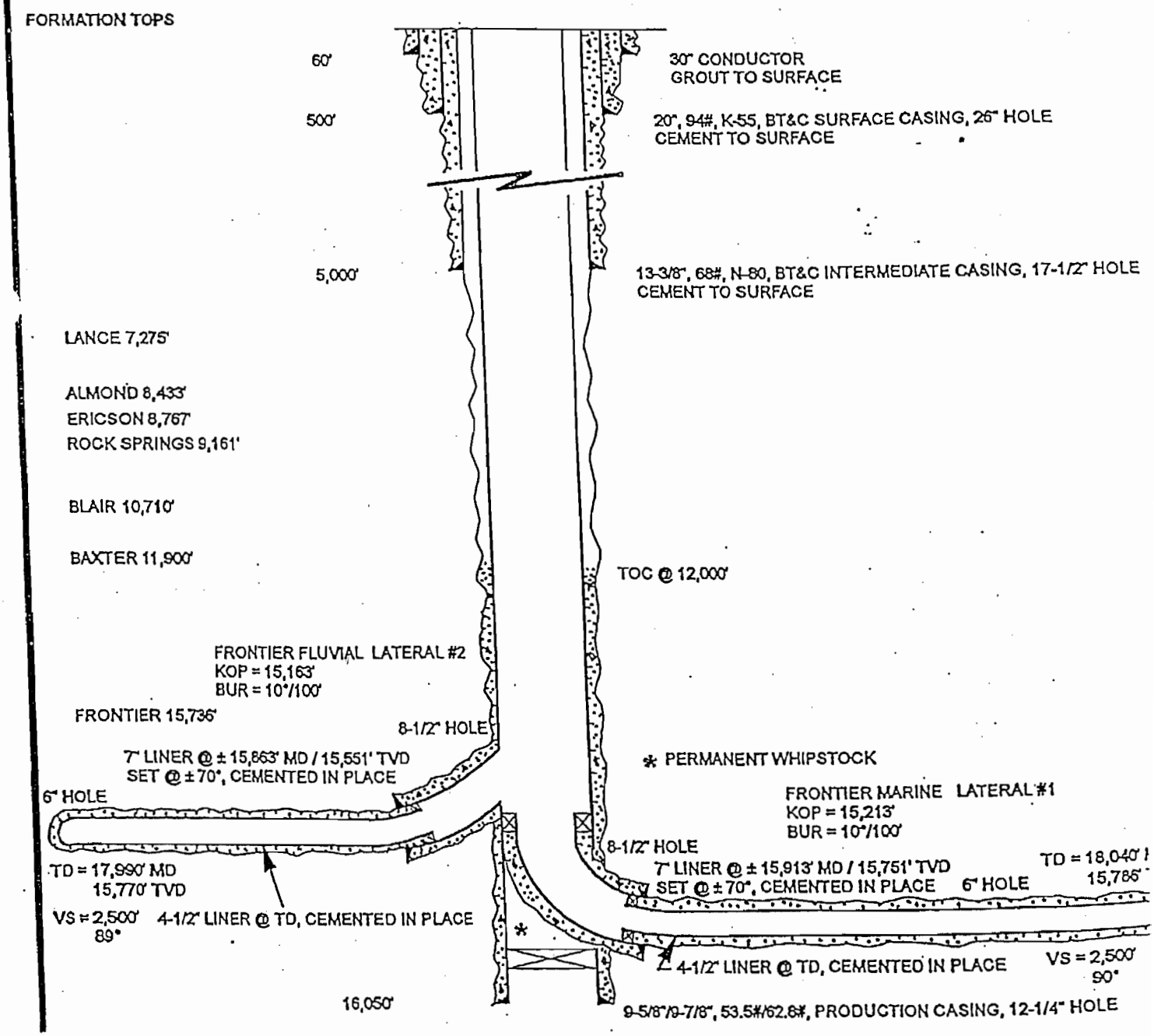
TOTAL DEPTH - 16,250' MD
TOTAL VERTICAL DEPTH - 16,245'

Union Pacific Resources

A Subsidiary of Union Pacific Corporation

UPRC - STRATOS FEDERAL UNIT #1
HORIZONTAL LATERALS #1 & #2

1,320' FSL & 1,320' FEL	SWEETWATER, CO. WYOMING	17,990' MD / 15,770' TVD
SECTION 24, T22N, R107W	GREEN RIVER BASIN DEEP	FRONTIER SAND



Stratos Stress and Well Testing

CER and Branagan and Assoc. (with BJ Services) conducted the cased hole stress tests in November, 1995 and the breakdown treatment (with Halliburton) in January, 1995.

Problems were encountered with the cased hole stress tests, only the bounding shale intervals were tested, and the recording of the pressure data after the breakdown treatment stopped before fracture closure occurred. The measured closure stresses (ISIP's) were high, estimated at 0.9 to 1.0 psi/ft.

A pre-frac well test, involving an eight day flow period followed by a two week pressure buildup was conducted after the well was broken down with KCl water. Integrated Petroleum Technologies (IPT) interpreted the well test.

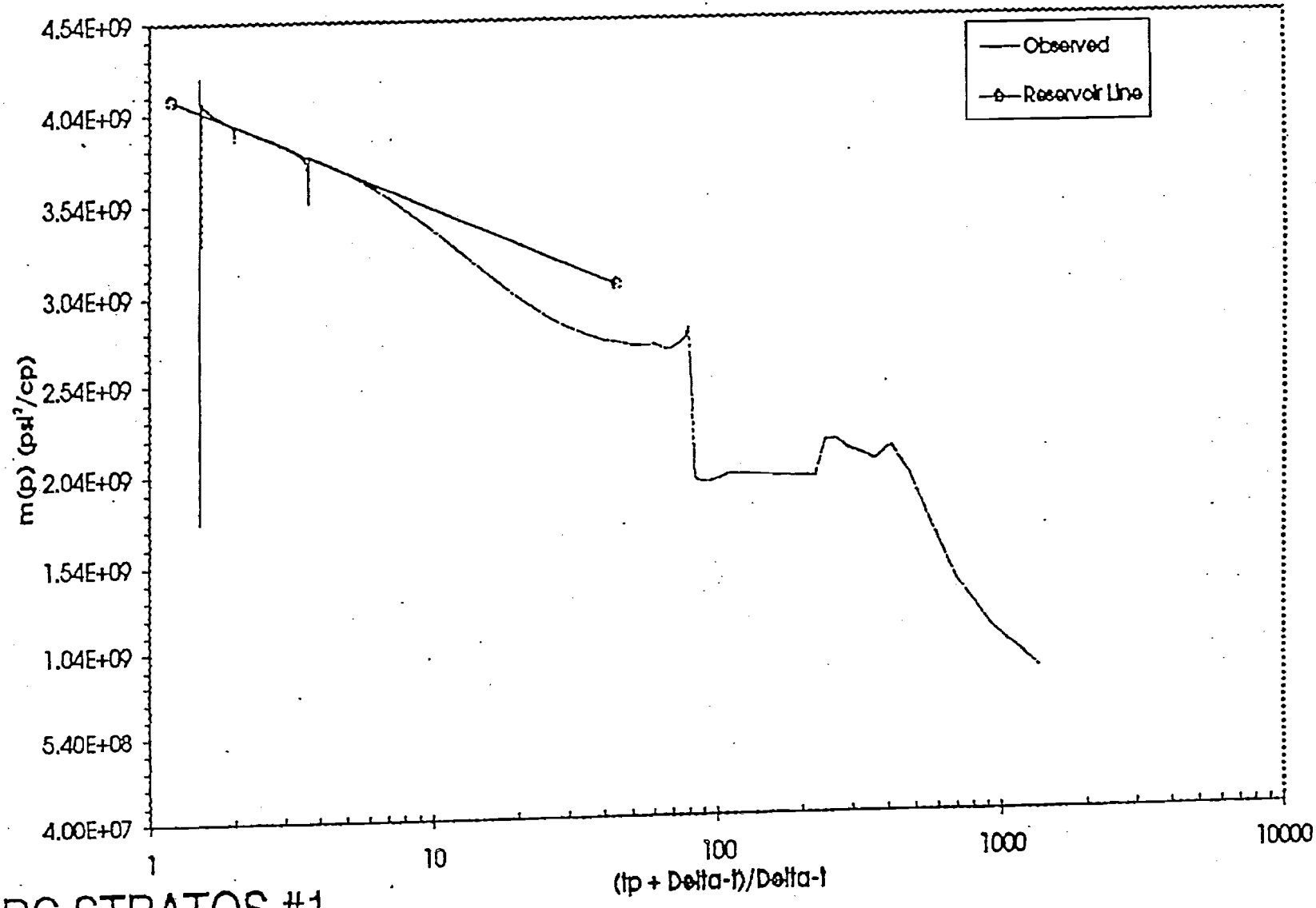
Stratos Stress and Well Testing

The test showed low permeability, of 0.036 md-ft, equal to a permeability of 0.001 md with a net pay of 30 feet.

Problems occurred with the well test that may have contributed to low measured value:

- *early time leaks occurred in the downhole shut off valves,*
- *a 4,000 ft water column was on the formation resulting in reduced actual as well as relative permeability,*
- *a limited radius of investigation, on the order of 10 feet.*

Horner Plot of the Pressure Build-up Data

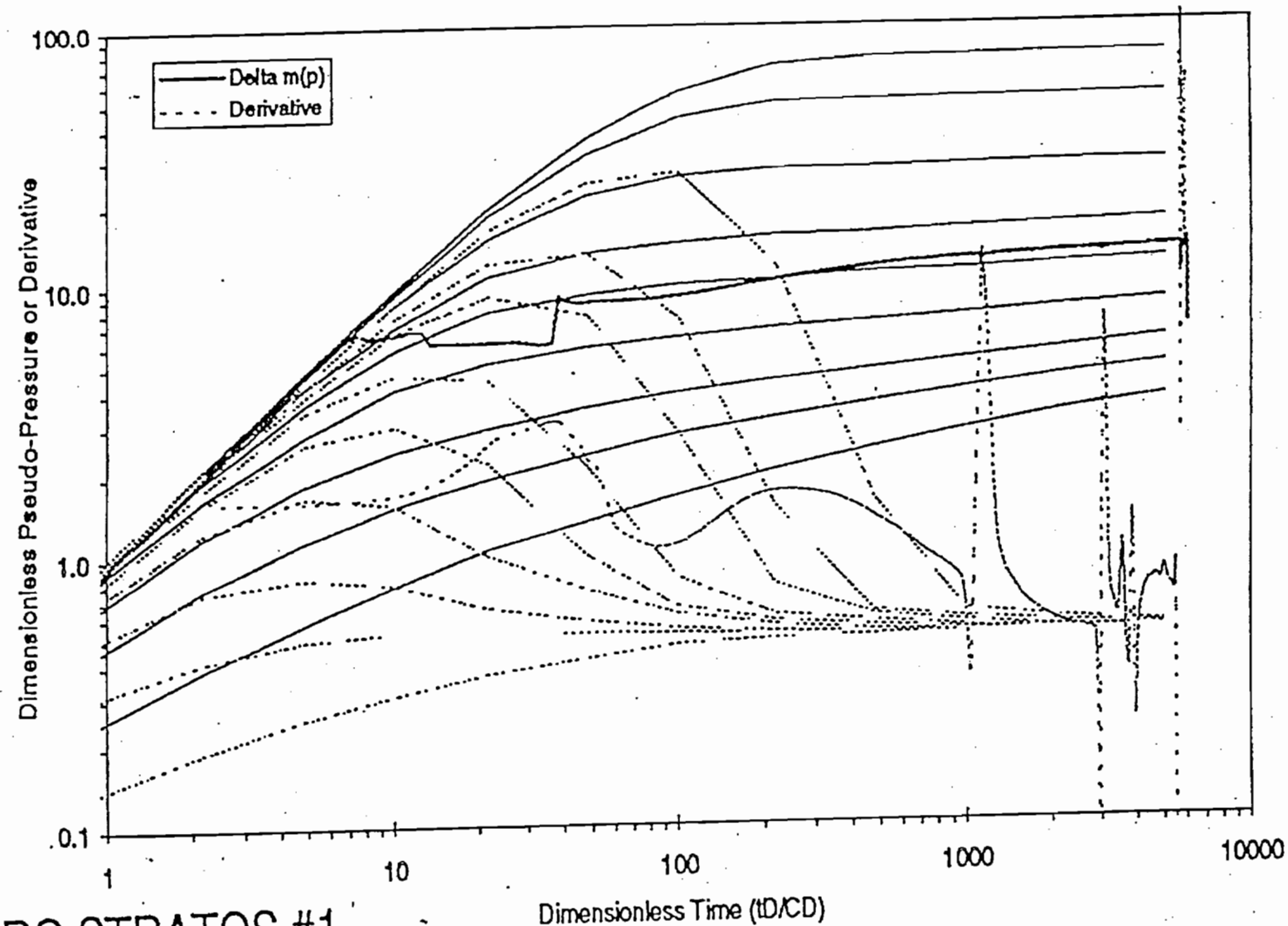


UPRC STRATOS #1

Advanced Resources International, Inc.

IAD2222.PPT

Log-Log Plot of the Delta Pseudo-Pressure vs Delta Time of the Build-up Data



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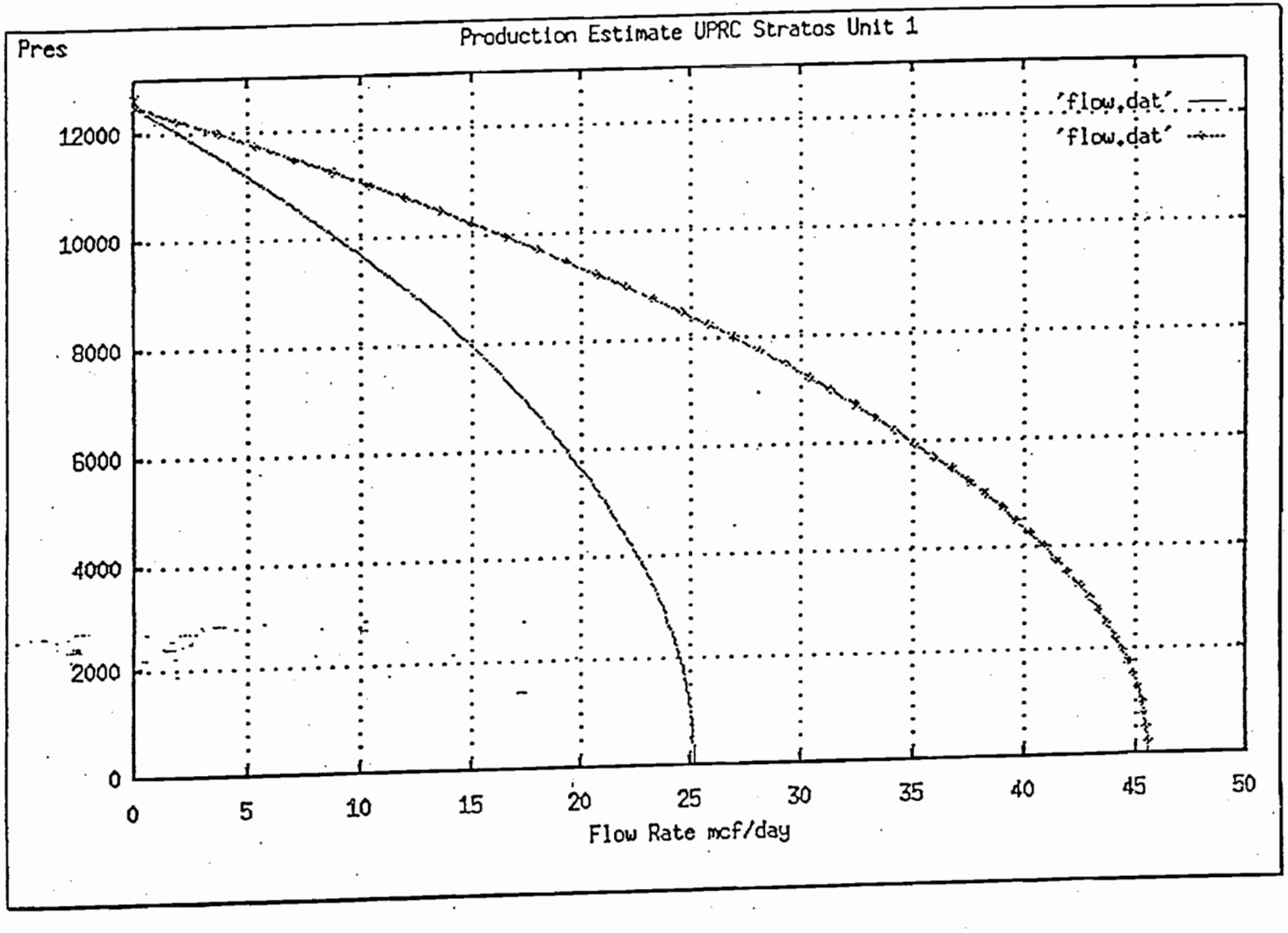
Completion Procedures and Production Results

Well	Total Zone phi(h)	Casing Perforation		Perforation Breakdown				Hydraulic Fracture Stimulation			
		Flowrate Mcfgpd	STIP psi	Treatment Type	Amount	Flowrate Mcfgpd	SITP psi	Fluid	Sand	Flowrate Mcfgpd	SITP psi
). 31-1 *note 1*	3.659	100-120	no report at least 1,800	10% Acetic 7.5% HCl 2% KCl wtr	92 bbls 96 bbls 88 bbls	690-817	10, 050	1929 bbls gel	71,000 lb sand	1797	12,400
). 1-30 *note 1* note 2	6.014	1316 ?	6000 to 7000	7.5% HCl 2% KCl wtr	119 bbls 119 bbls	378 ?		2514 bbls gel ?	150,000 lb sand ?	1316 ?	
deral No.1	2.78	no flow to surface	190 to 450	3% KCl wtr	50 bbls	18-20	6,000				
er No.1-35	3.45			no production tests of the Frontier Formation							

pper Mowry sandstone was perforated and treated in both the Federal No.31-1 and Federal No. 1-30 wells.
letion information on the Federal No. 1-30 well is questionable. Source in supervisory role at location during entire completion operation reports
failure of 3.5 inch liner and tubing occured immediately after perforating. Extremely high pressures were encountered and it was not possible to
bottom for further treatment of Frontier interval. Shortly thereafter cement was placed in the well bore to secure and temporarily abandoned the hole.
er reports shut-in pressures after perforation of between 6000 and 7000 psi.

Benchmark Estimates Inside Performance Line is a Natural Completion and the Outside IPR Line is After a Moderate Frac



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Assessment of Performance

It may be improper to have the structurally unfavorable location of the Stratos well and the post completion practices on the Blue Rim wells condemn the Frontier gas play in the Green River Deep partition.

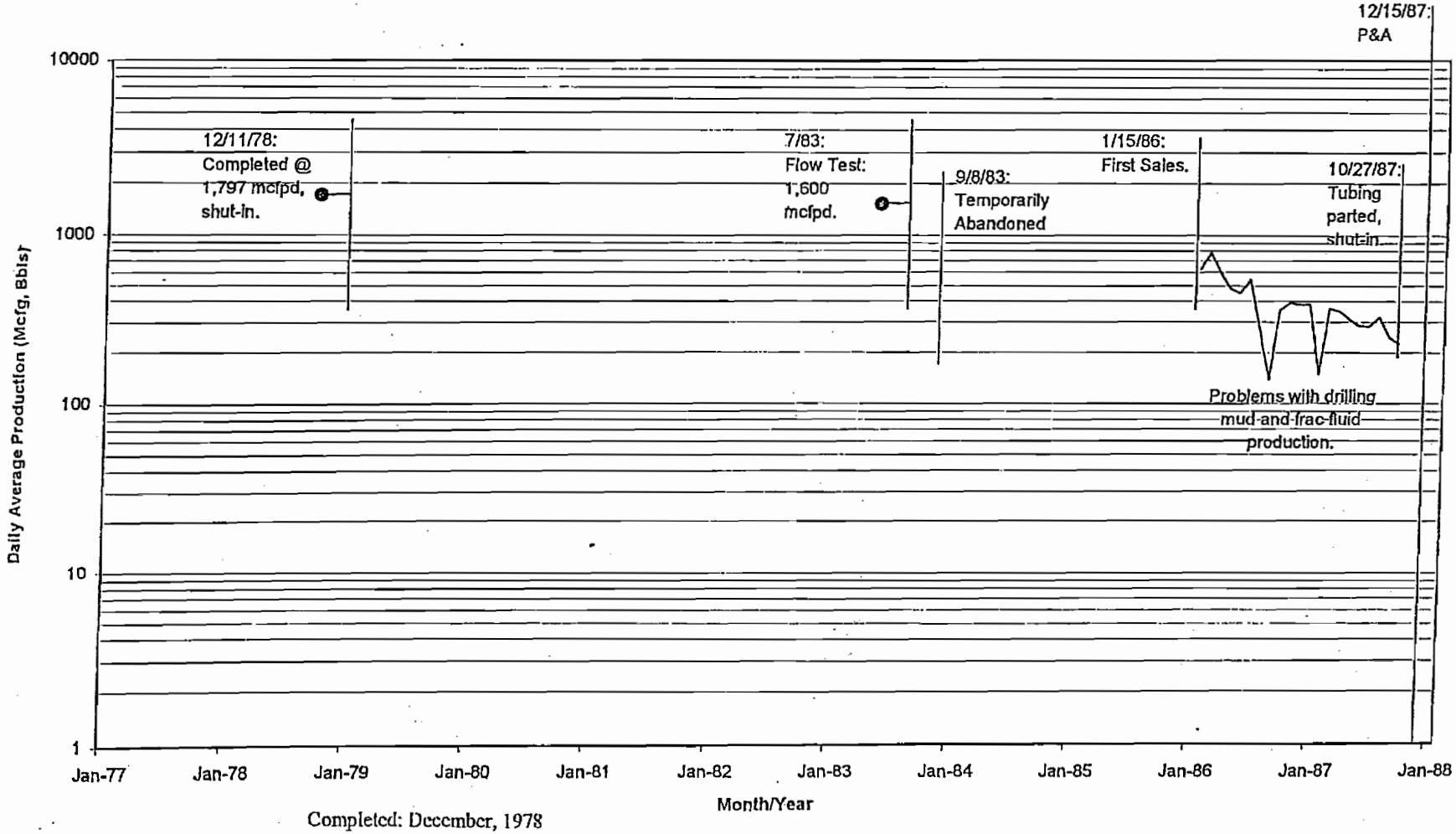
As an alternative view, the structurally more favorably located Blue Rim 31-1 well is used as a benchmark for performance. Matching of gas production in this well shows:

- *Permeability of 11 μd and a small, possibly damaged stimulation.*
- *Vertical well recoveries of 1.9 to 2.8 Bcf per well, depending on actual, undamaged reservoir permeability,*

Use of horizontal laterals of 1,000 to 2,000 feet would provide 4 to 8 Bcf per well, depending on actual reservoir permeability.

Production History: Federal 31-1

NW, Sec. 31, T22N, R69W



Completed: December, 1978
Cumulative Production:
0 Bbls Oil
152,816 Mcfg
0 Bbls Water

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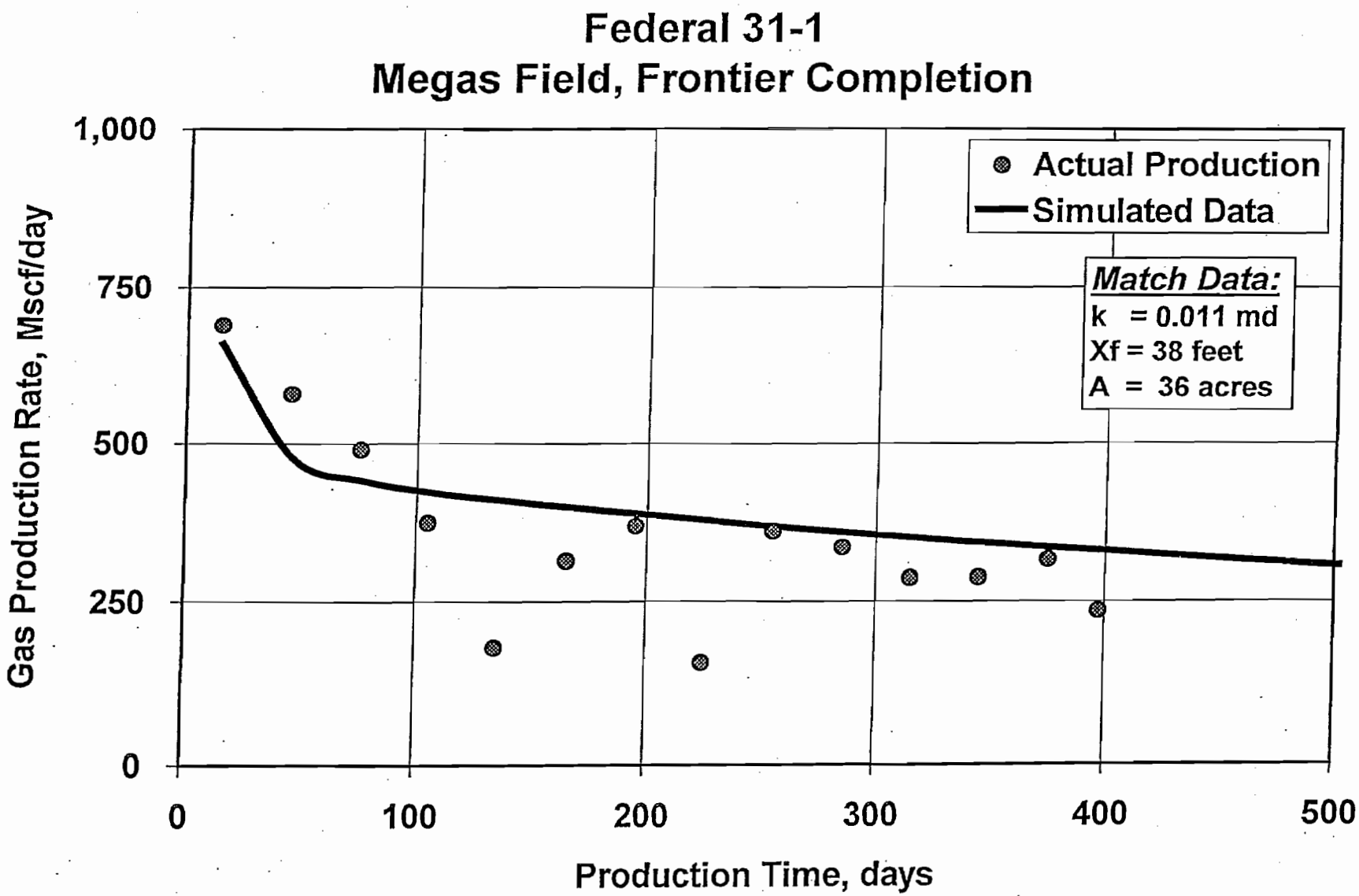
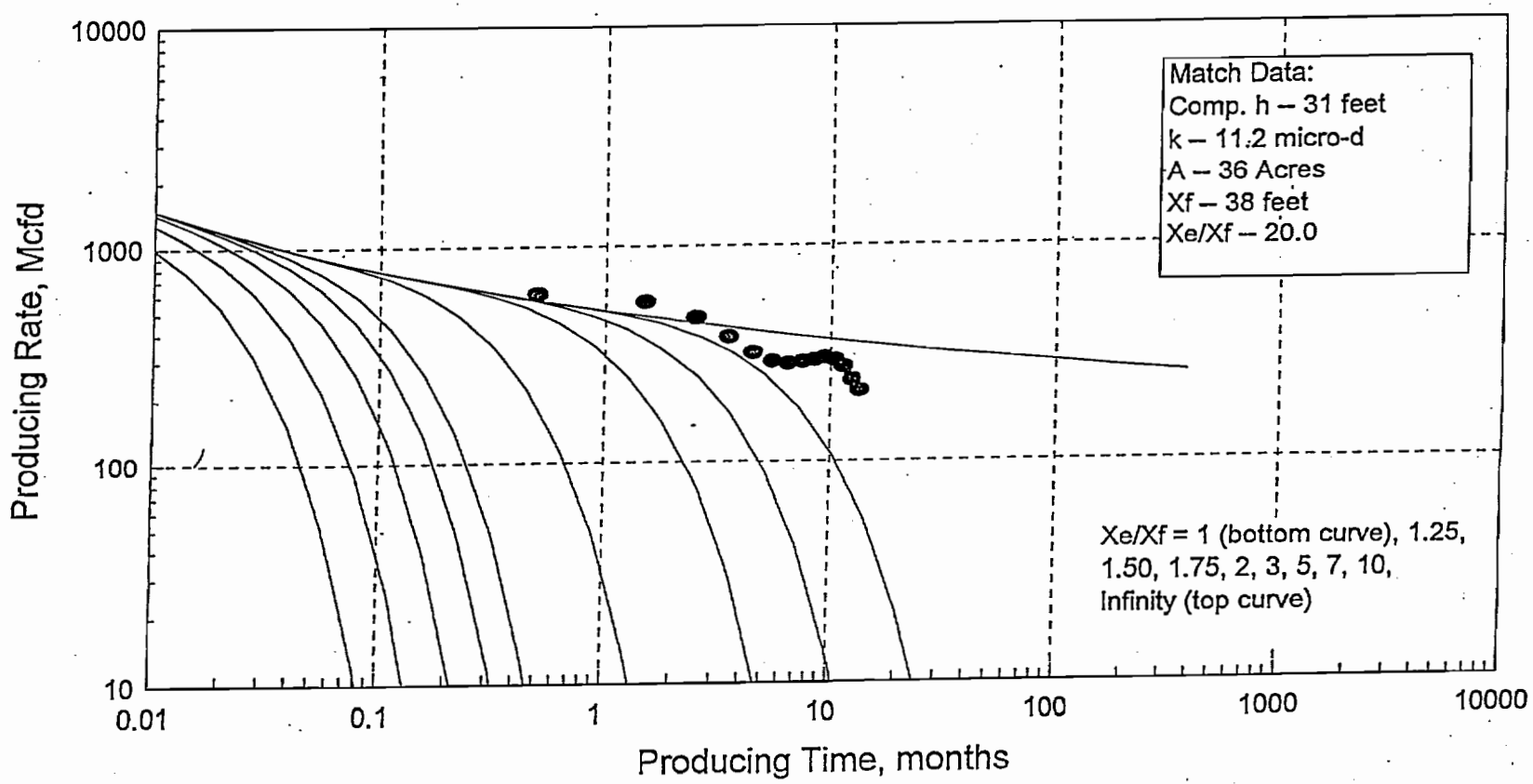

Federal 31-1
Megas Field, Frontier Completion
Actual Production
Simulated Data
Match Data:
k = 0.011 md
Xf = 38 feet
A = 36 acres
Gas Production Rate, Mscf/day
1,000
750
500
250
0
0
100
200
300
400
500
Production Time, days

FRONTIER 31-1

(Ye/Xe=1)



Estimated Gas Recovery: 30 Years

(Blue Rim 31-1 Reservoir Assessment)

Permeability (μ d)	Vertical Well[1] (Small Frac) (Bcf)	Vertical Well Horizontal Laterals (Bcf)	
		1,000 ft.[2]	2,000 ft.[3]
10	1.9	4.1	-
20	-	5.6	-
25	2.8	-	8.3

1 *Uses 160 acre spacing per well*
2 *Uses 320 acre spacing per well*
3 *Uses 640 acre spacing per well*

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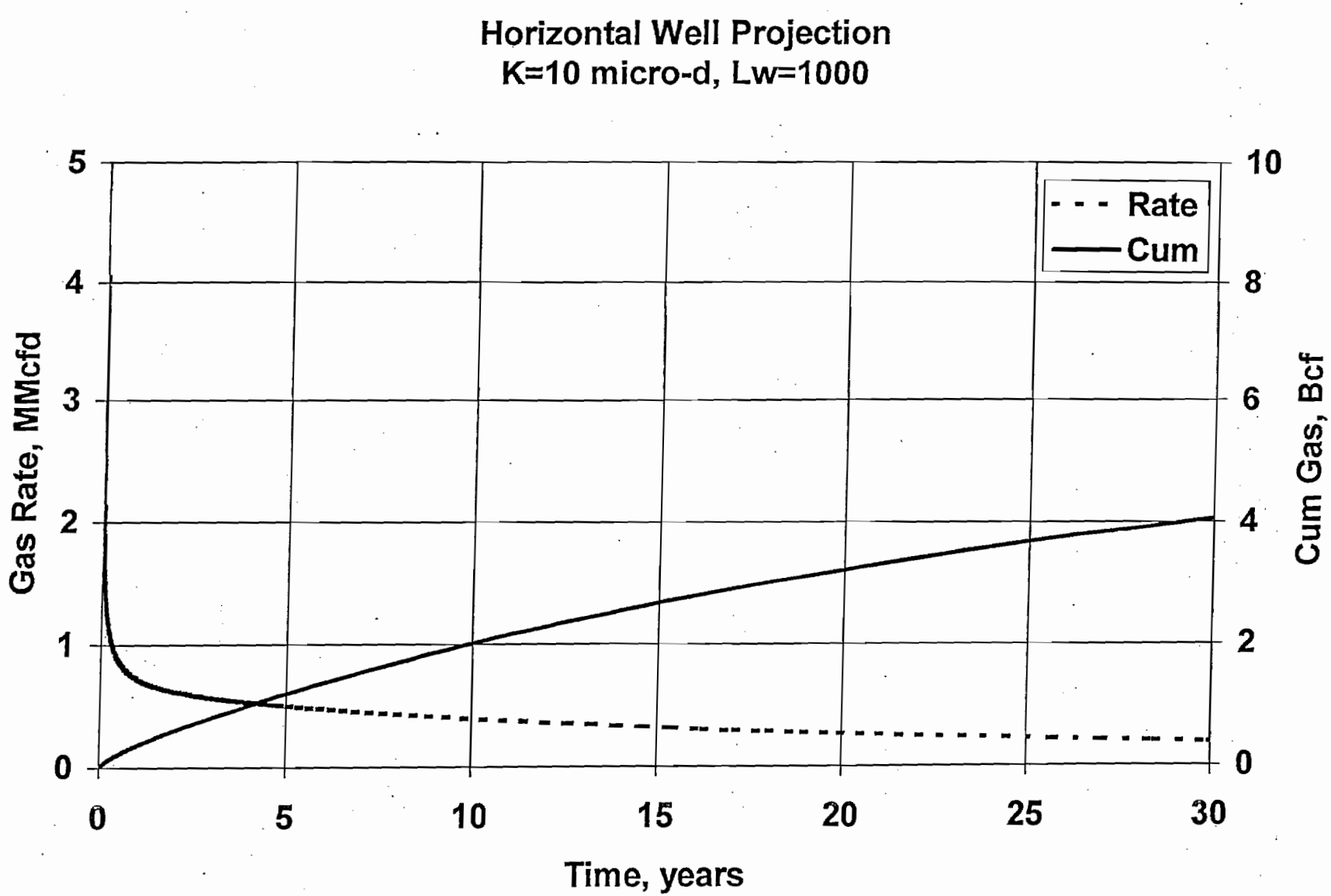
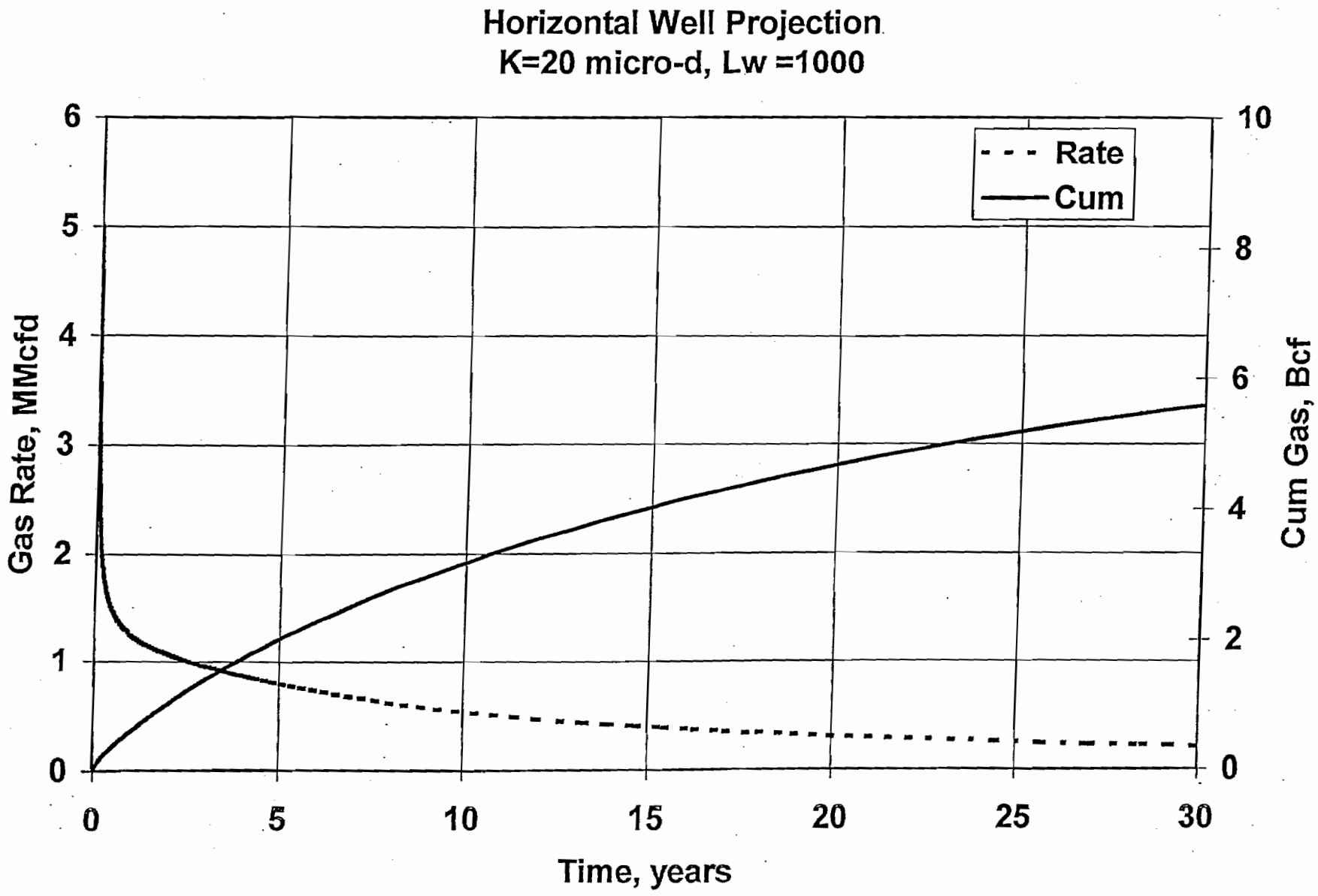

Horizontal Well Projection
K=10 micro-d, Lw=1000
Rate
Cum
Gas Rate, MMcfd
Cum Gas, Bcf
Time, years
0
1
2
3
4
5
0
2
4
6
8
10
0
5
10
15
20
25
30


Horizontal Well Projection
K=20 micro-d, Lw =1000
Rate
Cum
Gas Rate, MMcfd
Cum Gas, Bcf
Time, years
0
1
2
3
4
5
6
0
2
4
6
8
10
0
5
10
15
20
25
30

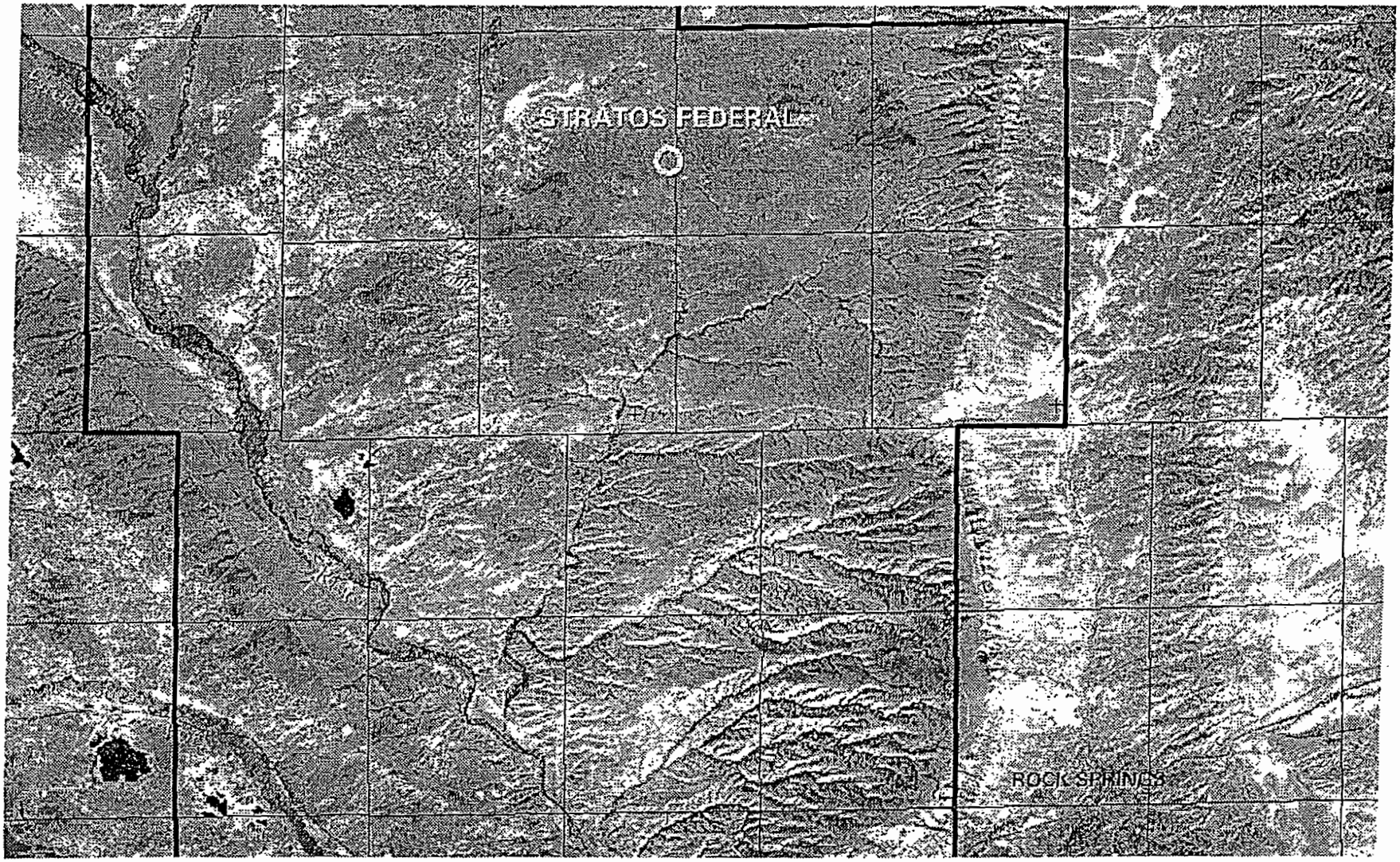
Findings and Conclusions

The following findings and conclusions stem from the Comparative Analysis of the Stratos Federal No. 1 Well.

1. Based on information from offset Blue Rim and other Frontier Formation wells and an assessment of surface and basement features in the Greater Green River Basin, the Stratos well location, while reasonably representative of the geology and deposition in the area, does not appear to be in a structurally favorable setting.

2. The Stratos well area has sufficient gas in place, estimated at 20 to 30 Bcf/section, to support natural gas development if sufficient reservoir drainage area could be connected to the wellbore.

Satellite Image Analysis:
Landsat Thematic Mapper Image Mosaic



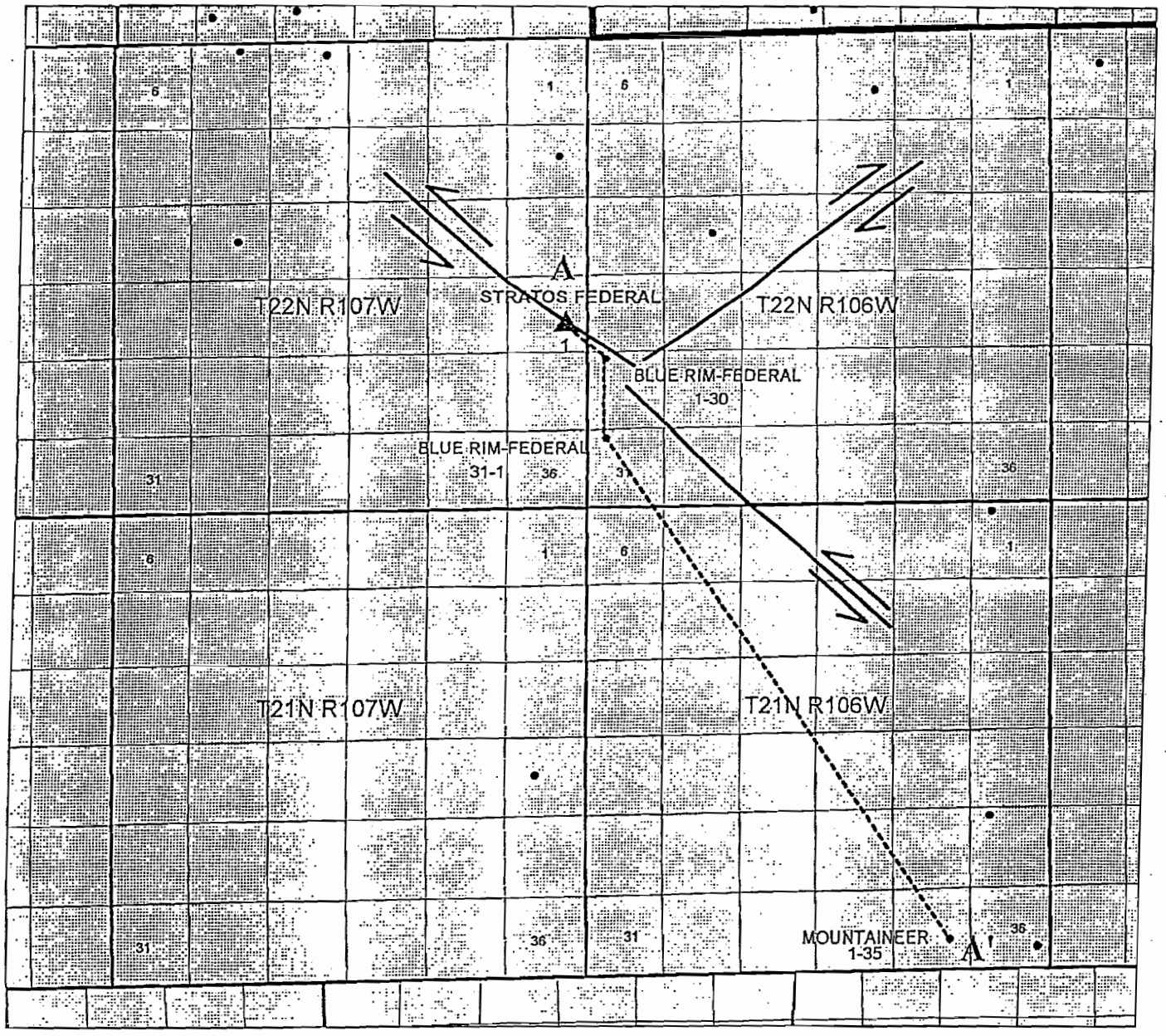
Findings and Conclusions

3. The reservoir matrix permeability of the Frontier sands in the area is extremely low, on the order of one micro-darcy. Natural fractures are required to overcome low matrix permeabilities and provide sufficient flow capacity and reservoir drainage area.

4. The structural setting around the Stratos well appears to be less favorable than around the Blue Rim 1-30 and 31-1 wells:

   - All three wells are located on the southeastern flank of the Sandy Bend Arch, about one mile apart.
   - The Stratos well is located in the compressional quadrant of a minor, left-lateral wrench/shear fault that terminates beyond the Stratos well. Such a structural setting is not be favorable for natural fracture based permeability.
   - The Blue Rim 31-1 well is located in the tensional quadrant of a second, minor left-lateral wrench/shear fault. This structural setting is favorable for open natural fractures and enhanced permeability.
   - The Blue Rim 1-30 well is located at the junction of two left-lateral wrench/shear faults and the termination of a right-lateral wrench/shear fault, trending perpendicular to the north-east. Based on this, the well may be in a neutral or slightly tensional setting conducive to natural fractures.

Green River Deep - Stratos Study Area Faults



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Findings and Conclusions

5. The two Blue Rim wells were completed in the Second Frontier and the deeper, upper Mowry sands. The Stratos well was not completed in the upper Mowry sand.

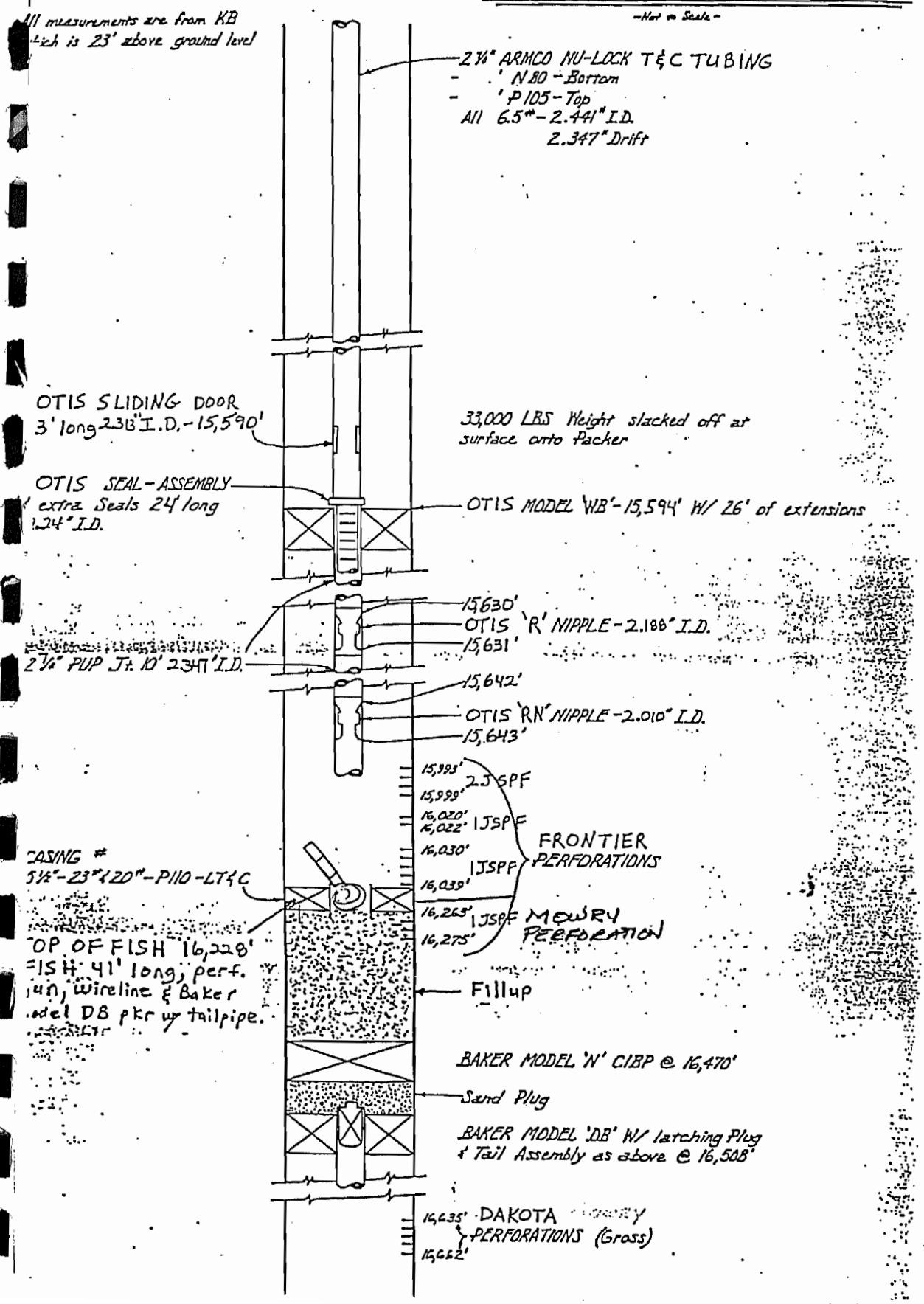
- *The Mowry sandstone represents 20 to 25% of the pay volume in the Blue Rim wells. The Mowry appears to be a relatively shaly sand (GR of 50 to 75), but has good Neutron-Density cross-over, reasonable porosity (9%), is gas bearing, and is over pressured.*

- *The Mowry interval, most likely, contributed to the initial flow tests. However, the Mowry perforations were plugged during the 18 months of production by the Blue Rim 31-1 well and thus made little to no contribution to post stimulation gas production.*

"WELLBORE SCHEMATIC"

BLUE H.M FEDERAL 31-1
MEGAS FIELD
C NW/4 SEC. 31, T. 22 N. R. 106 W.
SWEETWATER COUNTY, WYOMING

-Not to Scale-

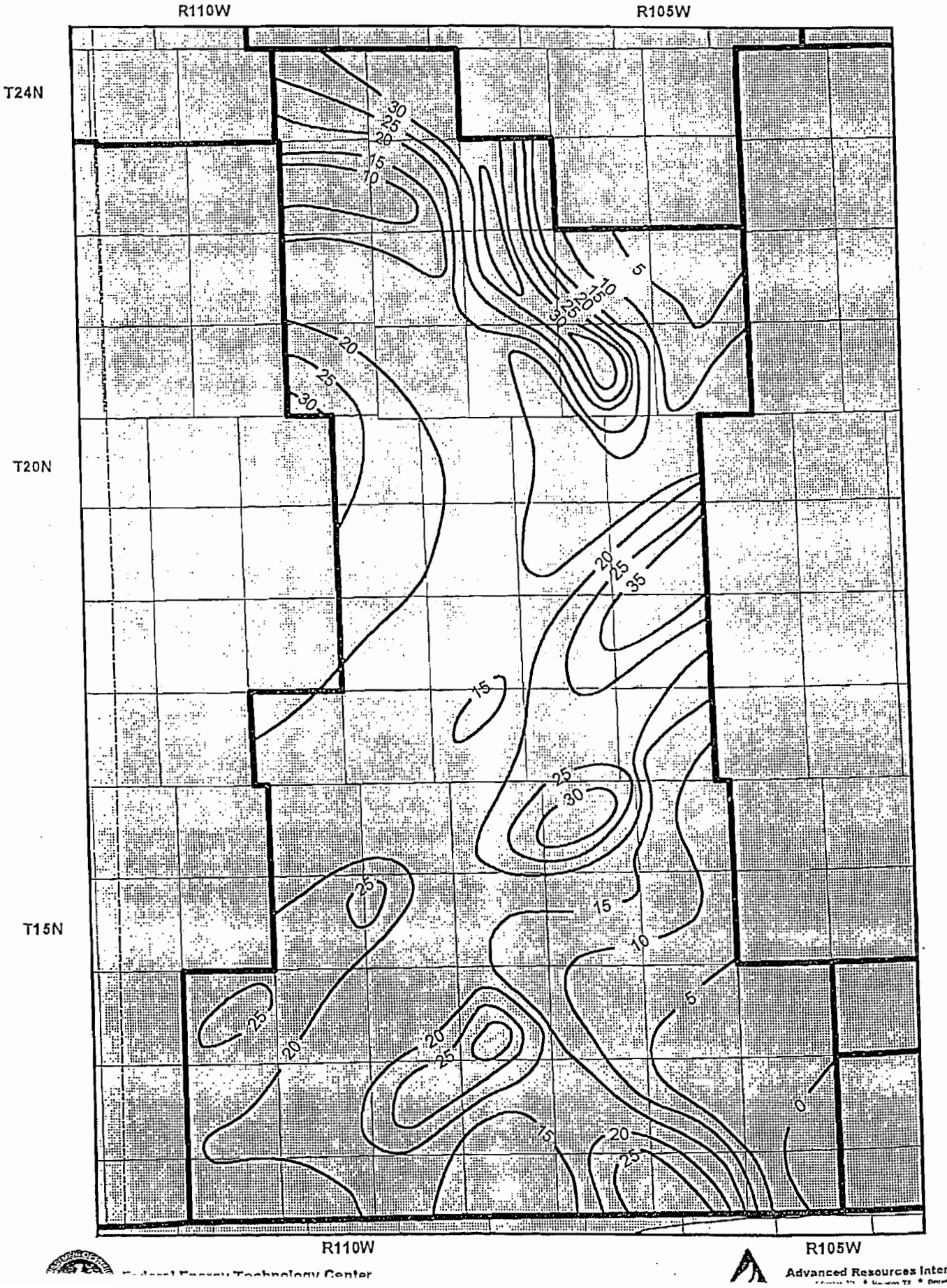


Findings and Conclusions

6. The composite 2nd Frontier including the fluvial and marine sands, is best developed in the Blue Rim 1-30 well. In the Blue Rim 31-1 and the Stratos wells, the net pay is similar, at about 30 feet.

Well	Gross Sand (ft)	Net Sand ≤GR50 (ft)	Net Sand <6% (ft)	ϕ (h)	Mean ϕ	Post-Brkdn Flow (Mcfd)
Stratos Federal No. 1	47.0	33.0	30.0	2.780	.076	18-20
Blue Rim Federal No. 31-1	42.0	33.0	31.0	2.710	.080	690-817
Blue Rim Federal No. 1-30	59.0	57.0	56.0	4.811	.082	1316

Green River Deep Partition
Total Net Sand of the Frontier



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Findings and Conclusions

7. While the Frontier deposition and net pay are similar in the three wells, major differences exist in their gas flow capacities:

	Stratos No. 1 Well	Blue Rim 31-1 Well	Blue Rim 1-30 Well
Post Perforation			
- Flow rate (Mcfd)	no flow	100 to 120	(?)
- SITP (psi)	450	1,800+	6,500
Post Breakdown			
- Flow rate (Mcfd)	18 to 20	690 to 817	1,316
- SITP (psi)	6,000	10,050	n/a
Post Stimulation			
- Initial Flow rate (Mcfd)	n/a	1,797	1,316(?)
- SITP (psi)	n/a	12,400	n/a
- Initial month (Mcfd)	n/a	700	n/a

Findings and Conclusions

8. Without running a quantitative stress and natural fracture location model, our interpretation of the reasons for the differences in flow capacity between the Stratos and the two Blue Rim wells are as follows:

   - *The permeability in the area surrounding the Stratos well appears to be too low for commercial gas production. Tectonically-related natural fractures (essential for high productivity) are a distinctly local phenomena. The Stratos well is located on the unfavorable, compressional quadrant of the left-lateral wrench fault that cuts through the area.*

   - *The Blue Rim wells appear to be more favorably located with respect to the tectonic setting of the area and thus have higher natural fracture based permeability.*

Findings and Conclusions

9. We do not believe that the Frontier Formation in the Green River Deep Partition has been conclusively tested:

   - *The Blue Rim 31-1 well, that produced 150 MMcf of gas in 18 months, was a damaged well; it produced drilling muds and frac fluid until the tubing parted and the well was abandoned.*

   - *The Blue Rim 1-30 well, that had a strong IP of 1,316 Mcfd, experienced mechanical problems and was never placed on production.*

   - *The pressure transient tests on the Stratos well are inconclusive because the early time data (required for calculating a skin factor) are missing, the depth of investigation was low (at 10 feet), and other problems were encountered.*

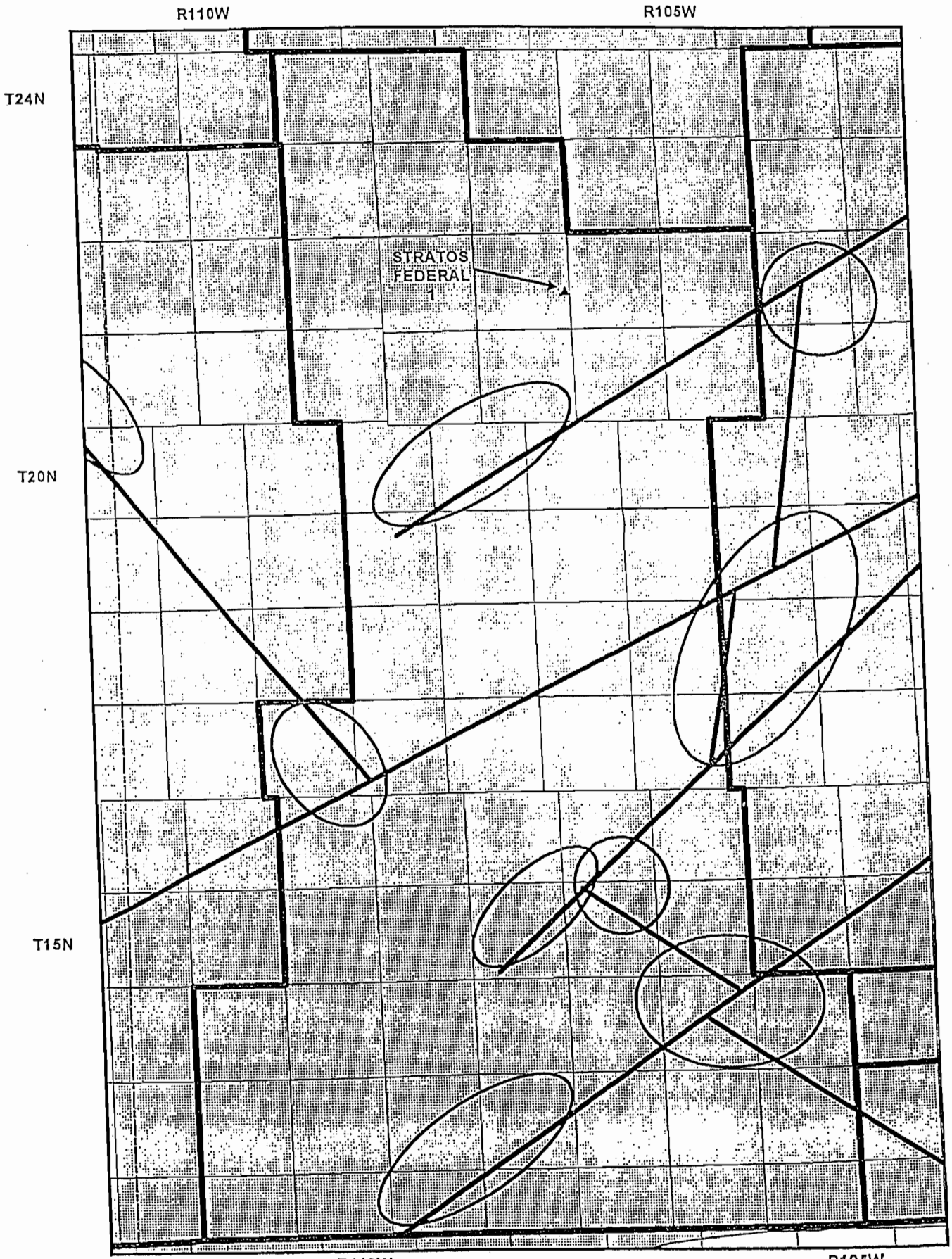
Findings and Conclusions

9. (Continued):

- *It may be that the unstimulated Stratos well was not efficiently connected to the natural fracture system in the area. Drilling fluids, cement or other actions, including the taking of core, may have damaged the near wellbore area. A hydraulic fracture or a horizontal lateral may have enabled the well to achieve contact with undamaged or improved reservoir properties past the wellbore area.*

- *The Stratos well is not located in any of the structurally enhanced target areas outlined for the Green River Deep Partition. These areas are likely to be more favorable for natural fracture based permeability and development of the tight Frontier gas formation.*

Green River Deep Partition
Structural Elements



Advanced Resources Internation

Findings and Conclusions

10. A more thorough evaluation of the Stratos well area may be warranted if the well is to be converted to a R&D test well. This evaluation would involve:

- *Acquiring and interpreting a high resolution aeromagnetic survey.*
- *Interpreting existing 2-D seismic for structural implications.*
- *Conducting a high resolution 3-D seismic survey.*
- *Evaluating the local natural fracture development using a rock mechanics and stress model.*

It may also be prudent to redo the well tests and stress tests on the Stratos well.

Appendix D

Individual Descriptions of the Partitions

Dad Dixon Platform Partition

The Dad Dixon Platform is located in the east-central part of the GGR basin in a foreland position relative to thrusting associated with basin-bounding Park Range. Structurally, the platform dips westerly at a relatively shallow angle toward the Washakie Deep.

- *The Frontier averages about 8000 ft. drill depth in the partition and is moderately penetrated. The partition is not overpressured.*
- *The platforms sits in an equivalent structural position to LaBarge platform, although exploration maturity and established production levels are not as great.*
- *Fields/completions:*

	# of Frontier Wells	Active Wells	Inactive/ Abandond Wells	Total Prod. (Bcf)
Browns Hill	1	0	1	0.06
Cherokee Creek	2	0	2	0.6
Sugar Creek	2	0	2	0.07

East Sand Wash Partition

The partition is located in a similar structural position as the Dad Dixon Platform, forming a homoclinal ramp toward the Sand Wash Deep. A tear fault, which bounds the the southern terminus of the upthrust Park Mountains defines the north edge of the partition.

- *The partition is moderately drilled and is overpressured only in its western third. Drill depth to the Frontier in the partition averages 10,000 ft.*
- *No significant production from the Frontier Formation exists in this partition.*

Red Desert Deep Partition

Located in the NE corner of the GGRB, the Red Desert Deep partition is a foreland deep relative to the Rawlins Uplift and shows a pronounced gravity signature.

- *Drill depth to the Frontier averages about 25,000 ft. and has penetrated by only four wells. The partition is overpressured.*
- *No significant production from the Frontier Formation exists in this partition.*

Red Desert Partition

The Red Desert partition covers much of the NE portion of the GGRB. Where it abuts the southern edge of the Wind River Mountains to the north, the partition is a foreland deep and displays a noticeable gravity signature and grades into the Red Desert Deep partition.

- *The average Frontier drilling depth in the partition is about 20,000 ft. The partition is overpressured and has not been drilled extensively in the Frontier.*
- *Fields/completions:*

	# of Frontier Wells	Active Wells	Inactive/ Abandond Wells	Total Prod. (Bcf)
Bastard Butte	1	0	1	0.04
Hay Reservoir	1	0	1	0.01
Uknown	1	1	0	0.11

Wamsutter Arch Partition

The Wamsutter Arch partition is on in a structural high relative to the Red Desert partition to the north and the Washakie Deep partition to the south. The arch may be the site of right-lateral oblique faulting, complementary to the Cherokee Arch.

- The partition has been slightly drilled in the Frontier. Here, the Frontier is 16,000 ft. deep an largely overpressured.
- *No significant production from the Frontier Formation exists in this partition.*

Washakie East Partition

The Washakie East partition comprises a steeper westerly-dipping ramp into Washakie deep from the Dad Dixon Platform.

- *Although drilling has been extensive in the Mesaverde section, drilling to the Frontier is sparse. The Frontier is found at drill depths of about 10,000 ft and the partition is overpressured.*

- *Fields/completions:*

	# of Frontier Wells	Active Wells	Inactive/ Abandond Wells	Total Prod. (Bcf)
Cow Creek	2	1	1	0.8

Washakie Deep Partition

Located in the east-central GGRB, the Washakie Deep may represent a rhombochasm between the Wamsutter and Cherokee arches. The partition displays a NE-SW gravity-low signature.

- *Drill depth to the top of the Frontier averages over 20,000 ft. Only about 15 wells have penetrated the Frontier in this partition, which is overpressured.*
- *No significant production from the Frontier Formation exists in this partition.*

Cherokee Arch Partition

The Cherokee Arch partition is a structurally high feature separating the Washakie Deep from the Sandy Wash area. The arch displays oblique right lateral faulting and may be a counterpart to the Wamsutter Arch to the north for accommodating stresses across the Washakie Deep.

- *Drill depth to the Frontier in the partition averages about 17,000 ft. The partition is overpressured and has not been extensively drilled.*
- *No significant production from the Frontier Formation exists in this partition.*

Sand Wash Deep Partition

The Sand Wash Deep partition is a foreland deep found east of the eastern terminus of the Unita Mountains uplift. Adjacent to the uplift, in the southwest portion of the partition, is a pronounced gravity low.

- *Drill depth to the Frontier averages about 18,000 ft. The Frontier is only moderately drilled around the perimeter of the partition, which is largely overpressured.*

- *No significant production from the Frontier Formation exists in this partition.*

Vermilion Sub-basin Partition

The Vermilion Sub-basin is sandwiched between the Washakie and Sand Wash Deep to the east, the Rock Springs Uplift to the NW, and the upthrusted 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.*
- *Drill depth to the Frontier Fm in the partition is about 13,000 ft. The partition is overpressured in areas adjacent to the Washakie Deep.*
- *Fields/completions:*

Fields	# of Frontier Wells	Active Wells	Inactive/ Abandond Wells	Total Prod. (Bcf)
Kinney	1	0	1	0.56
Middle Mountain	1	1	0	0.16

Washakie West Partition

This partition comprises the eastern dip and flank of the Rock Springs Uplift, transitional to Washakie Deep.

- ***It is relatively heavily explored, especially in the Mesaverde section, but is also well developed in the Frontier. The SE portion of the partition is overpressured.***
- ***Fields/completions:***

Fields	# of Frontier Wells	Active Wells	Inactive/ Abandond Wells	Total Prod. (Bcf)
Table Rock	2	1	1	1.45
Robin	1	1	0	2.2

North Rock Springs Partition

This partition includes the NE flank of the Rock Springs Uplift and displays relatively homoclinal NE-dipping strata into the Red Desert partition. It is separated from the Farson Deep on the NW by faulting.

- *Areally the partition is largely overpressured and is characterized by a drill depth of about 16,000 ft. The Frontier is penetrated by 18 wells in the partition.*
- *Fields/completions:*

Fields	# of Frontier Wells	Active Wells	Inactive/ Abandond Wells	Total Prod. (Bcf)
Treasure	1	1	0	0.07
Unknown	1	1	0	0.1
Unknown	1	0	1	0.006

Rock Springs East Partition

This partition comprises the eastern and southeastern flank of the Rock Springs Uplift as it dips toward the Washakie and Red Desert areas.

- *The partition is not overpressured. Drill depth to the Frontier is approx. 7500 ft. in the partition.*

- *Fields/completions:*

Fields	# of Frontier Wells	Active Wells	Inactive/ Abandond Wells	Total Prod. (Bcf)
7	26	16	10	38.04

Rock Springs Crest Partition

The partition sits astride the N-S striking Rock Springs Uplift and is bounded by late Laramide faulting on west side. The uplift displays a pronounced (high) gravity signature. Transverse, NE-SW trending faults are present on the crest of the Rock Springs Uplift.

- *Because of the uplift, the Upper Cretaceous section is normally pressured in this part of the GGRB. Drill depths to the Frontier are about 6500 ft.*
- *Fields/completions:*

Fields	# of Frontier Wells	Active Wells	Inactive/ Abandond Wells	Total Prod. (Bcf)
16	137	84	53	147.31

Green River Deep Partition

The Green River Deep partition, adjacent to the Moxa Arch, is bounded by a steep flank on the west and is fault-separated from the Rock Spring Uplift on the east. The northern edge includes the Sandy Bend Arch, a structurally high feature that separates the partition from the Farson Deep. The partition is bounded on its southern end by the upthrust Uinta Mountains.

- *Significant NW-SE basement faulting occur interior to the partition.*
- *The partition is overpressured. The Frontier is found at drill depths averaging about 16,000 ft. and has been penetrated by about 30 wells.*
- *Fields/completions:*

Fields	# of Frontier Wells	Active Wells	Inactive/ Abandond Wells	Total Prod. (Bcf)
Megas	1	0	1	0.15

Farson Deep Partition

Northwest of the Rock Springs Uplift, the Farson Deep is located in a foreland position to the upthrusted Wind River Mountains and exhibits a strong gravity signature. The partition is separated from the Rock Springs Uplift on the SE by faulting.

- *Drill depth to the Frontier averages about 20,000 ft. in the partition, which is overpressured. Twelve wells have penetrated the Frontier in the partition.*
- *Fields/completions:*

Fields	# of Frontier Wells	Active Wells	Inactive/ Abandond Wells	Total Prod. (Bcf)
Swan	1	0	1	0.001
Blue Forest	1	0	1	0.03

Pinedale Partition

The Pinedale partition is the site of a foreland deep associated with upthrusting of the Wind River Mountains. It shows a pronounced gravity low, but is differentiated from the Hoback (on the NW) and Farson deeps (on the SE) by the presence of the Pinedale anticline.

- *The drill depth to the Frontier averages approximately 18,000 ft. in the partition, which is overpressured. About 13 wells have been drilled into the Frontier in the partition. The partition is the site of the Jonah field, an upfaulted, overpressured Upper Cretaceous producer discovered in the early 1990s.*
- *Fields/completions:*

Fields	# of Frontier Wells	Active Wells	Inactive/ Abandond Wells	Total Prod. (Bcf)
Jonah	1	0	0	

Hoback Partition

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 partition axis is located adjacent to the Wind River Mountains and has a strong gravity expression.

- *The partition is overpressured and has only been moderately explored along its western side at the Frontier level. Drill depth to the Frontier in the partition averages about 20,000 ft.*
- *No significant production from the Frontier Formation exists in this partition.*

LaBarge Platform Partition

The LaBarge Platform is a foreland area relative to the Wyoming thrust belt (WTB) to the west. A left-stepping tear fault in the WTB has set the partition up as a sub-regional structural high. On its south side the partition transitions to the more shallow dip of the Moxa Arch.

- *Reservoirs of the Upper Cretaceous section in the partition are dominated by nonmarine sediments and are normally pressured. Drill depth to the Frontier is about 10,000 ft. The LaBarge Paltform is intensely drilled.*
- *Fields/completions:*

Fields	# of Frontier Wells	Active Wells	Inactive/ Abandond Wells	Total Prod. (Bcf)
42	1,296	1,136	160	

Moxa Arch Partition

The Moxa Arch partition is in a foreland position to the WTB located to the west. It is the site of generally shallow, southward dipping strata, gently folded into a N-S trending arch.

- *Similar to the LaBarge Platform, the Upper Cretaceous section is nomarine and was deposited in a fluvial-dominated environment. The crest of the Moxa Arch is normally pressured, but the flanks are overpressured. The level of exploration at the Frontier level is high.*
- *Fields/completions:*

Fields	# of Frontier Wells	Active Wells	Inactive/ Abandond Wells	Total Prod. (Bcf)
29	1,012	820	192	

Appendix E

ARI Presentation to DOE/FETC
"Table Rock Horizontal Drilling Project:
Summary and Results of
Geomechanical Analysis",
Morgantown, WV, May 12, 1999

Table Rock Horizontal Drilling Project: Summary and Results of Geomechanical Analysis

"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.

May 12, 1999

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Project Objectives

1. *Corroborate geologic rational of drilling location and horizontal drilling orientation for UPR/DOE Table Rock Frontier test.*

2. *Predict local development of natural fracture clusters from detailed fault mapping around the the Rock Island 4H well.*

3. *Evaluate play extent and assess resource in place.*

The Technical Program

The program was divided into three tasks:

1. Preliminary Assessment of Horizontal Drilling Plan
   - *A. Regional Structural Analysis*
   - *B. Regional Natural Fracture Assessment*
2. Structural Study for Identifying Possible Play Extensions
   - *A. Rock Island 4H Core Observations*
   - *B. Detail Fault Mapping*
   - *C. Prediction of Local Natural Fracture Clusters*
3. Regional Geologic Assessment of Play Economics
   - *A. Play Extent*
   - *B. Gas-in-Place*
   - *C. Economic Assessment*

Task 1. Preliminary Analysis

The first task involved a natural fracture prediction methodology that includes:

- **Natural Fracture Characterization**
  - Examination of the Govt. Union #4 and Frewen Deep #4 cores,
- **Regional Fault Mapping**
  - Table Rock and Continental Divide 3D Surveys
- **A preliminary geomechanical model of a regional fault geometry of the Table Rock thrust system.**

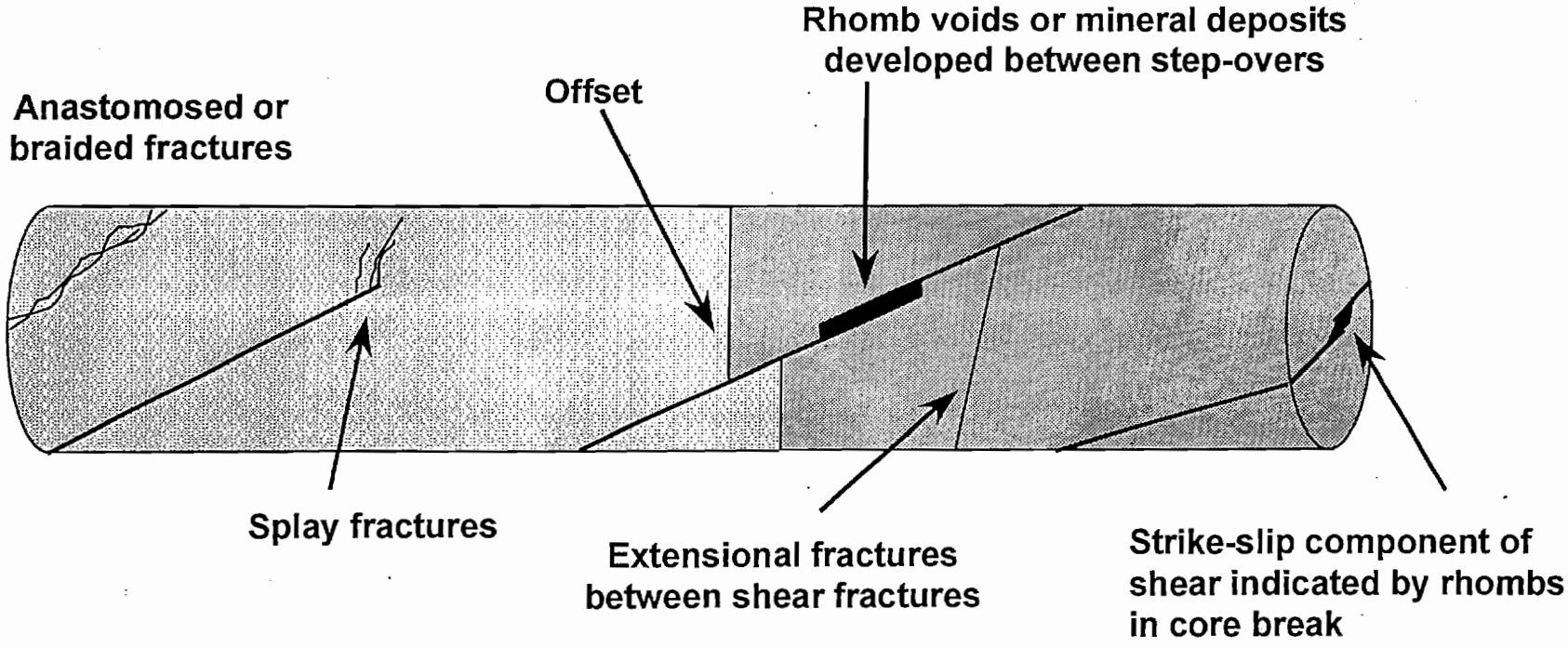
Natural Fractures Observed In Frontier Fm. Cores

The Govt. Union #4 core was examined and types of fractures identified include:

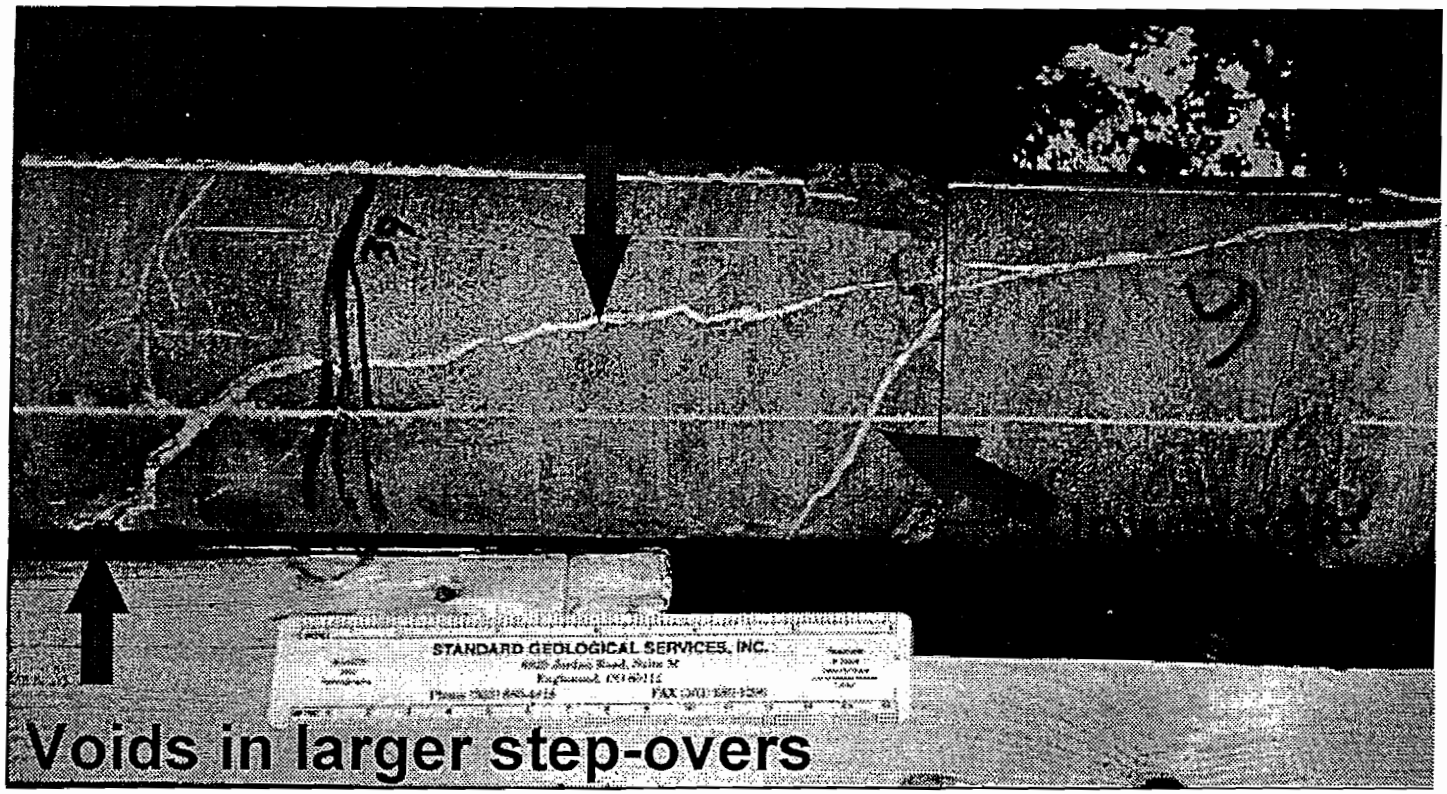
- Shear faults with an extensional component exhibiting oblique-reverse slip
- Bitumen-filled splay fractures
- Bedding plane fractures
- Minor extensional fractures

Natural Fractures Observed In Cores

Shear(ed) fractures are identified in core by:

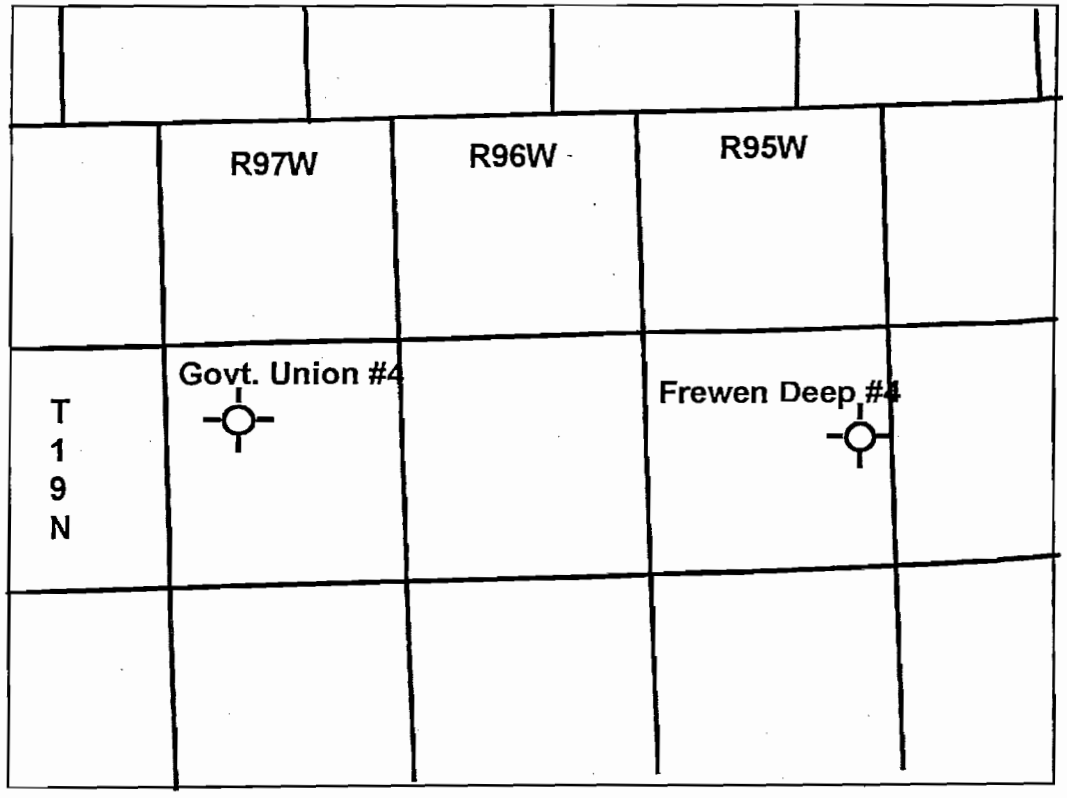


Govt. Union #4 Core



Frewen Deep #4 Core

17 miles East of the Govt. Union #4, Amoco's Frewen Deep #4 cored and tested the Frontier Fm.



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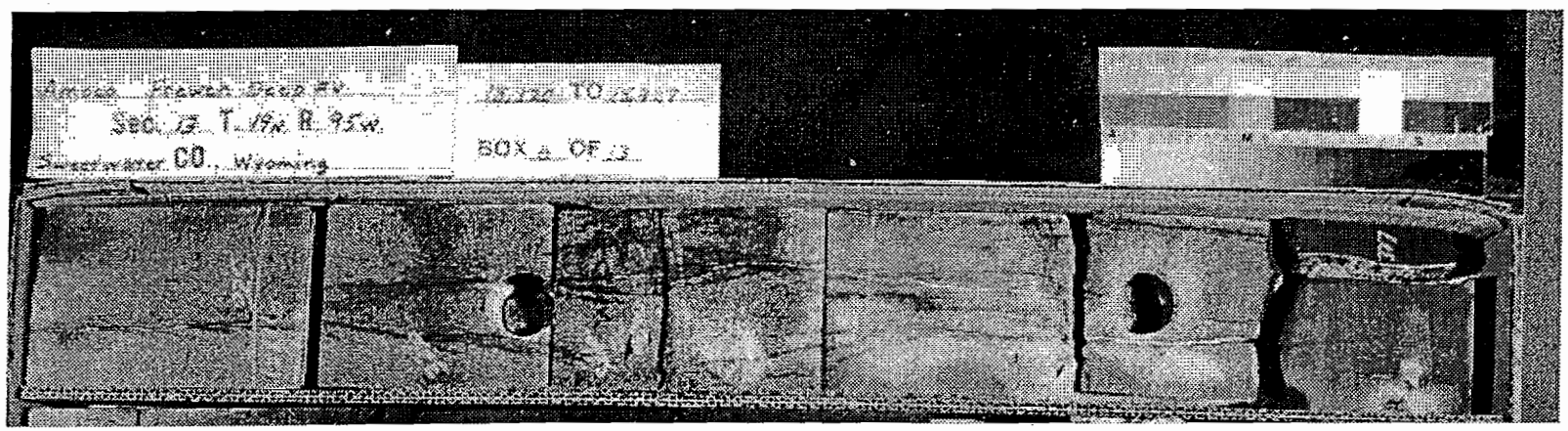
Frewen Deep #4 Core

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

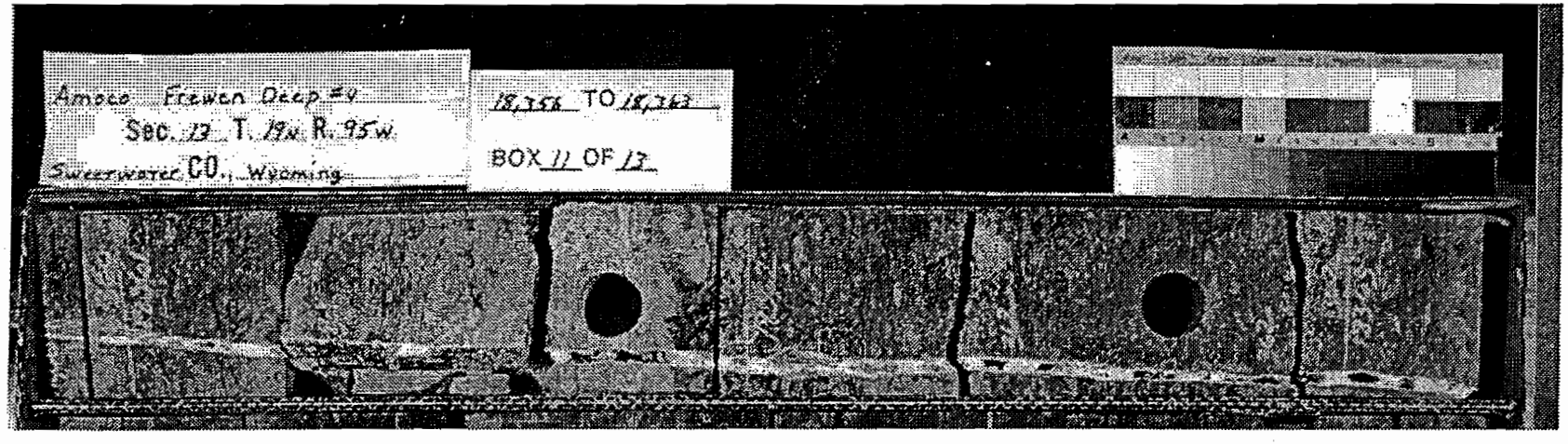
- Mineralized natural fractures (quartz and calcite) with large isolated apertures .
- "Irregular anastamosed fracture strands."
- Bitumen-filled splay fractures.

Frewen Deep #4 Core



Mineralized and bitumen-coated vertical fracture system

Frewen Deep #4 Core



Open vertical fractures system propped by quartz pillars.

Summary of Natural Fractures in Frontier Fm.

- The natural fractures in Govt. Union #4 are dominantly oblique-reverse sheared fractures with an extensional component.
- The natural fractures in Frewen Deep #4 are dominantly extensional.
- Open voids represent storage for gas whereas the <u>sheared fractures</u> provide the deliverability (i.e., the controlling factor in permeability).

Table Rock and Continental Divide 3-D Seismic Surveys

Analysis objectives:

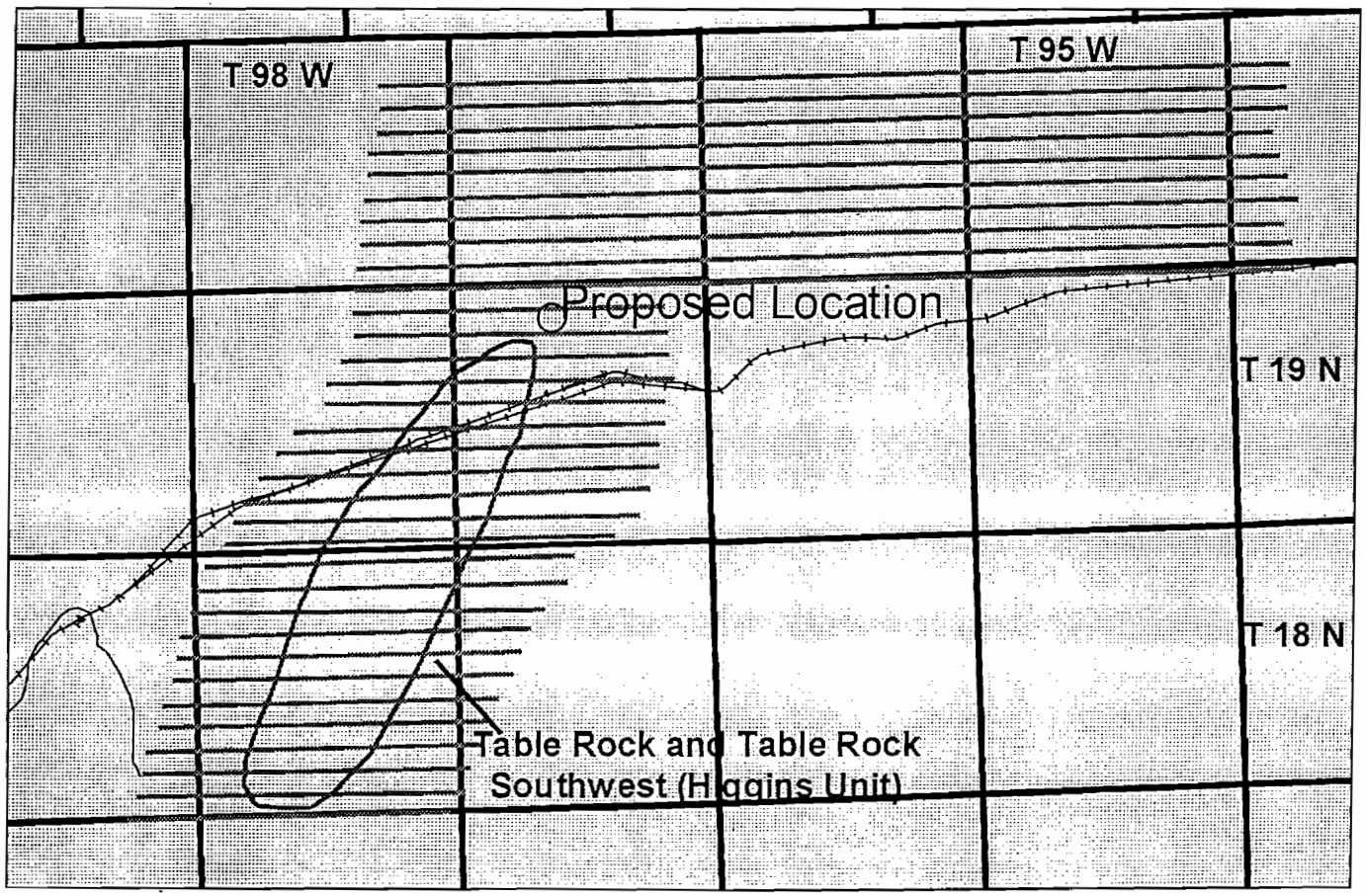
1) To examine history of deformation associated with fault systems and,

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



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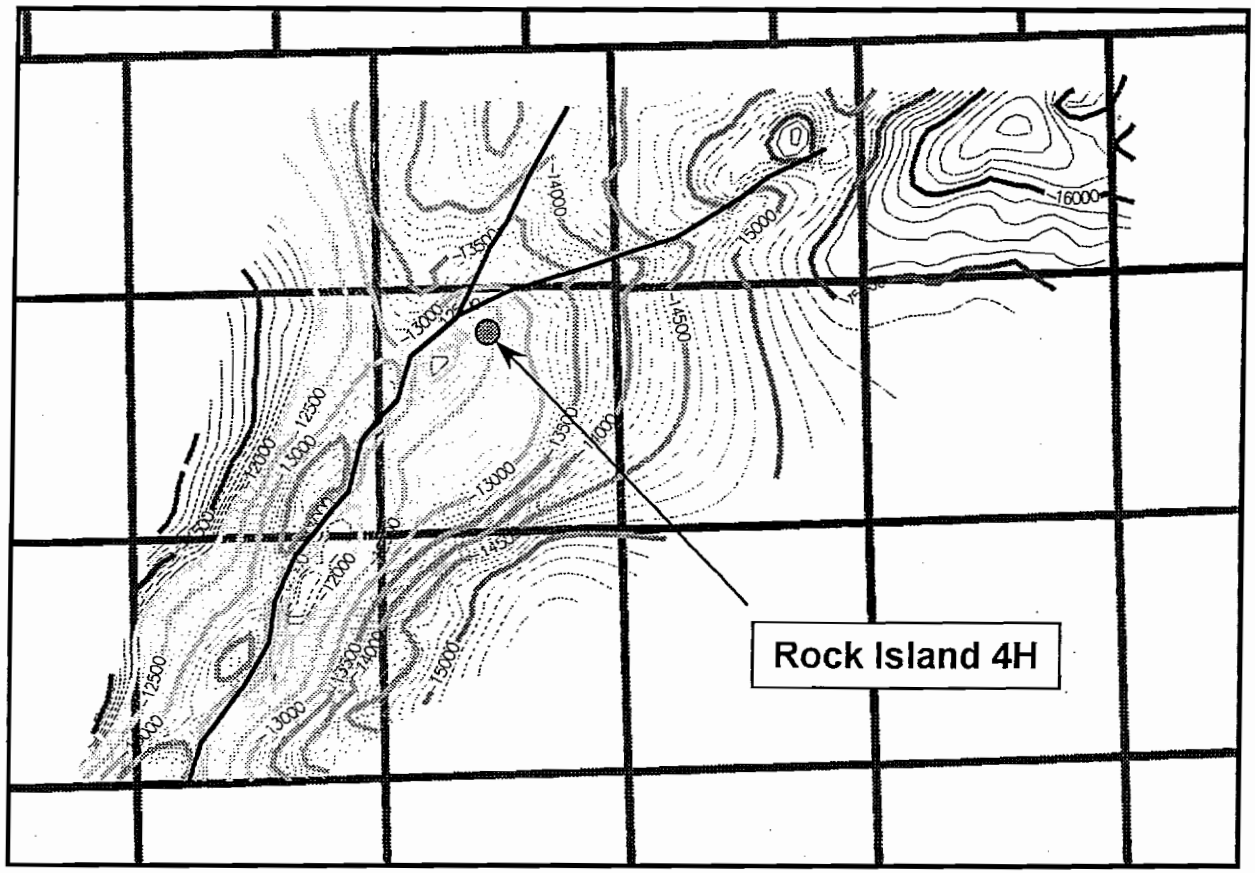
3-D Seismic: Fault Mapping

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.

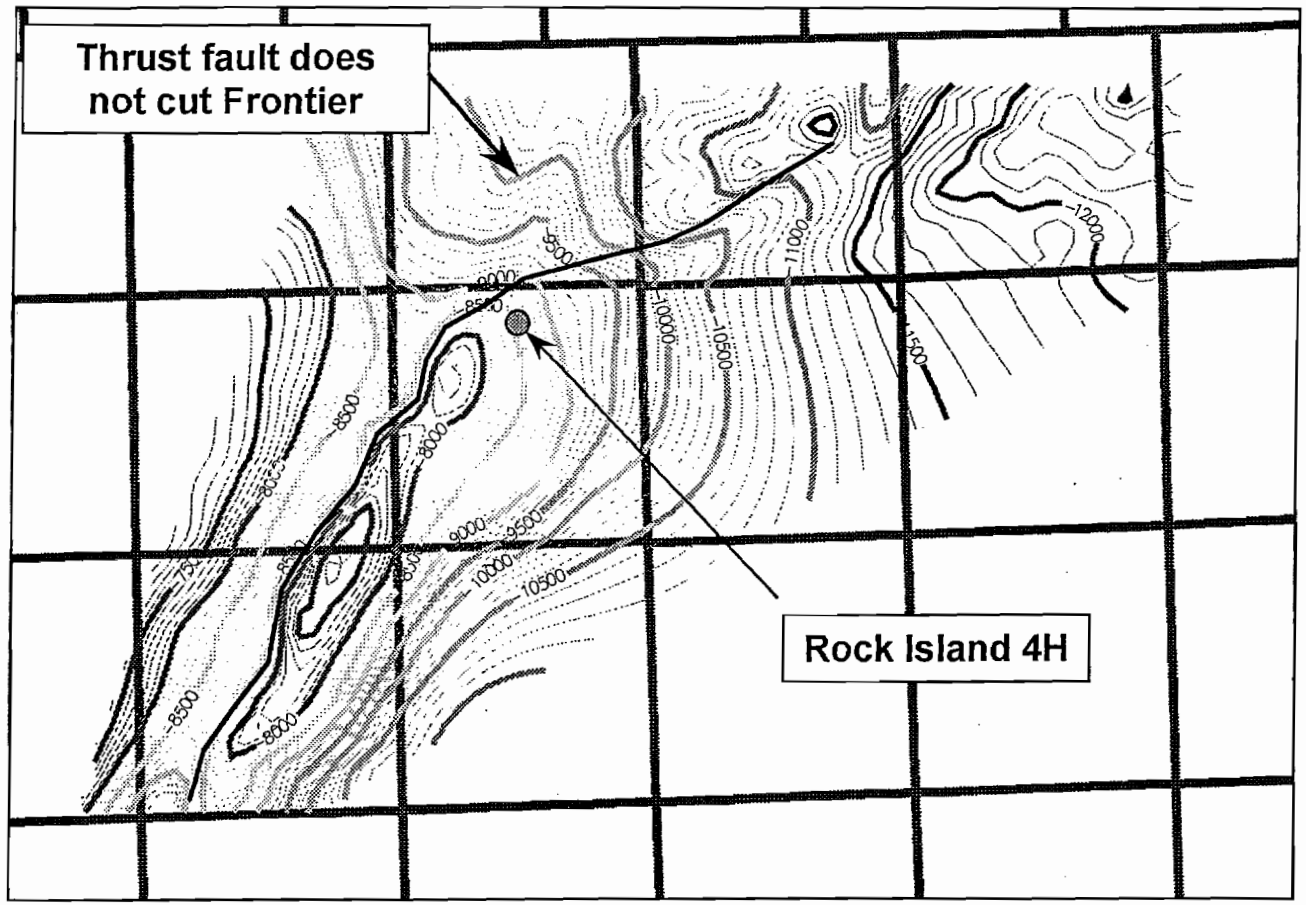


Subsea structure of the Madison Fm.

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.

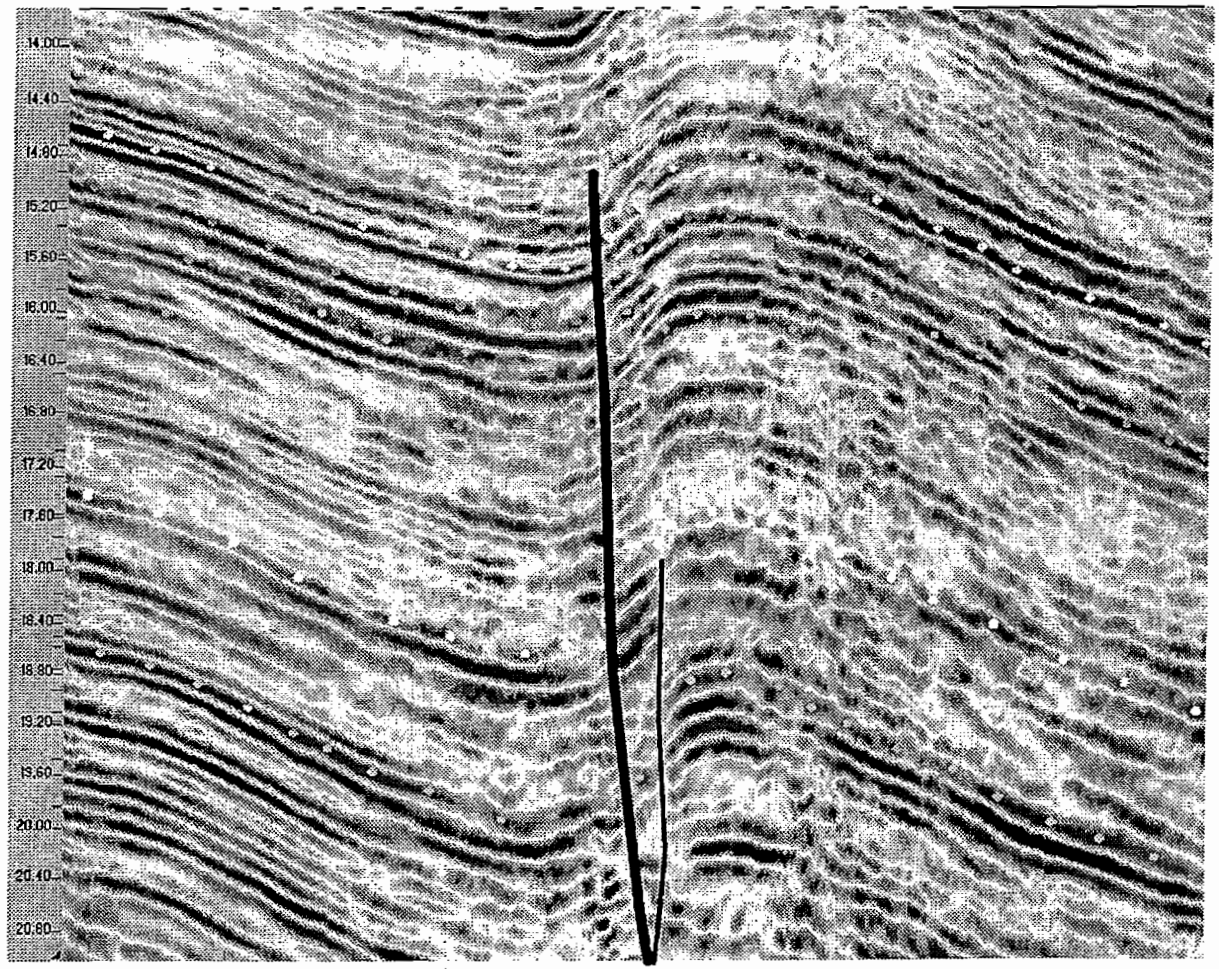


Subsea structure of the Frontier Fm.

3-D Seismic: Fault Mapping

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.

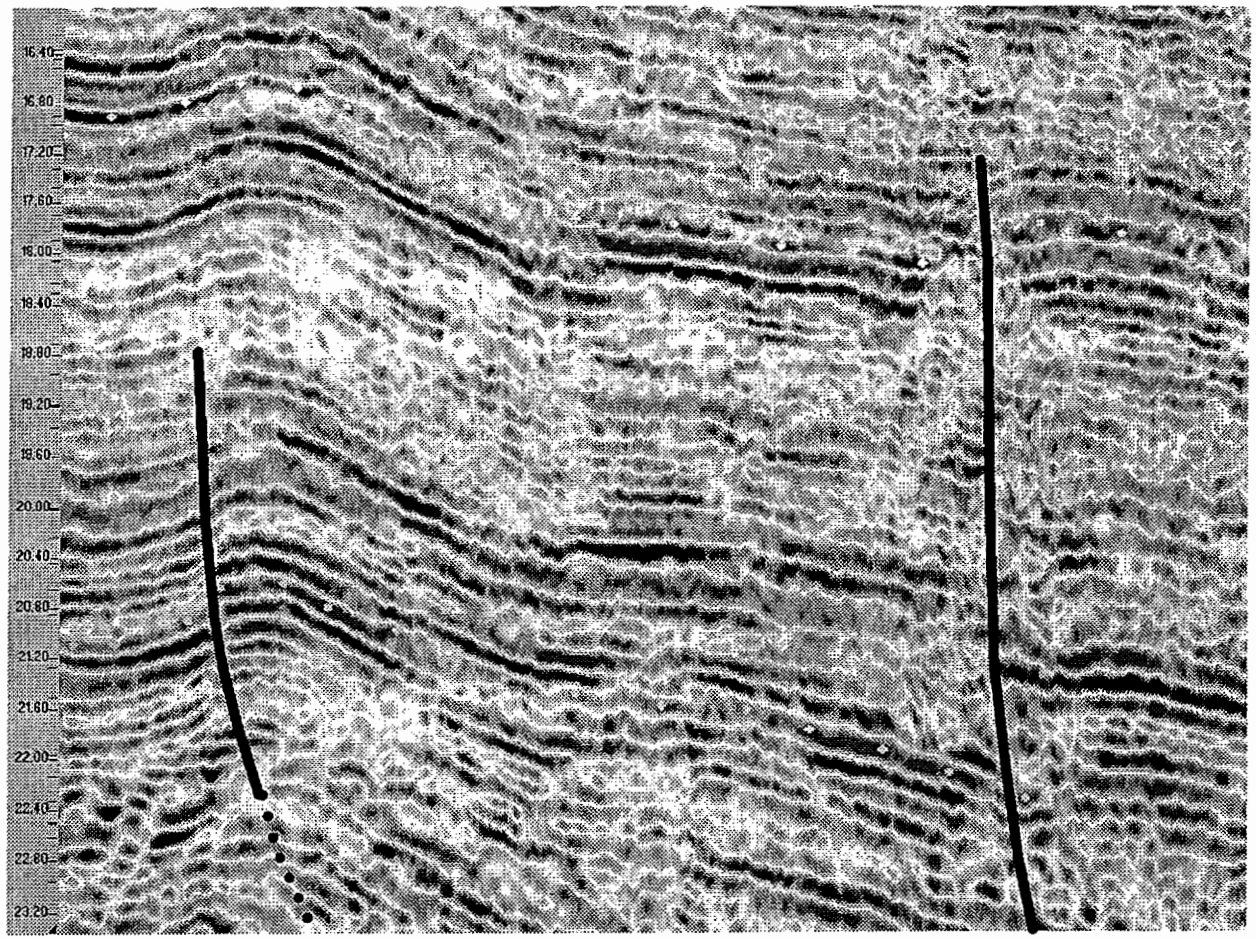


Frontier

Madison

3-D Seismic: Fault Mapping

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.



Frontier

Madison

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

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

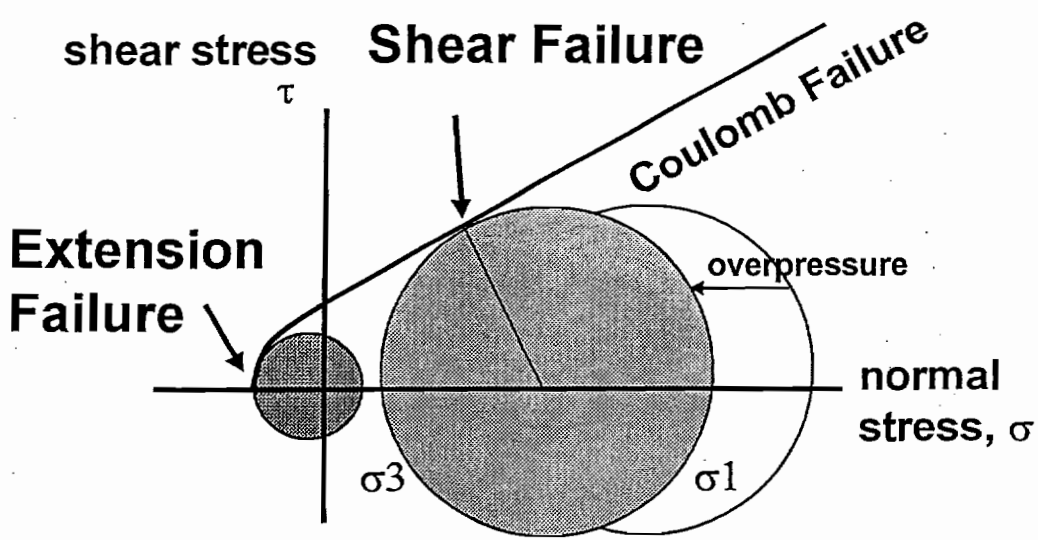
<u>Methods:</u> Numerical model is a 3-D BEM code that solves linear elastic equations for stress and displacement.

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 (Sc) 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.

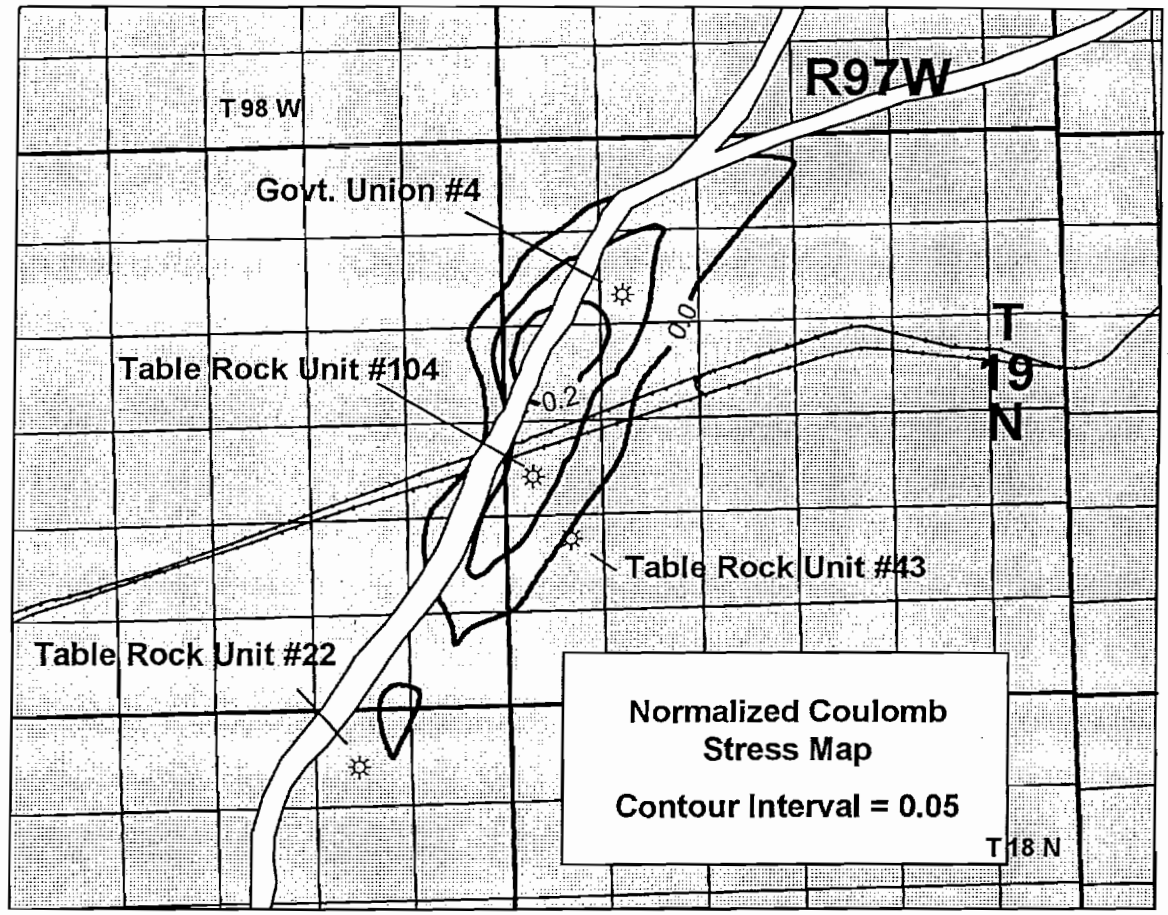
3-D Stress Model: Input Criteria

- **Inputs into model include:**
  - XYZ coordinates of fault geometry,
  - orientation of remote stresses deduced from displacement geometry
  - 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, m, was assigned 0.6, typical of sandstones.**

3-D Stress Model: Results

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

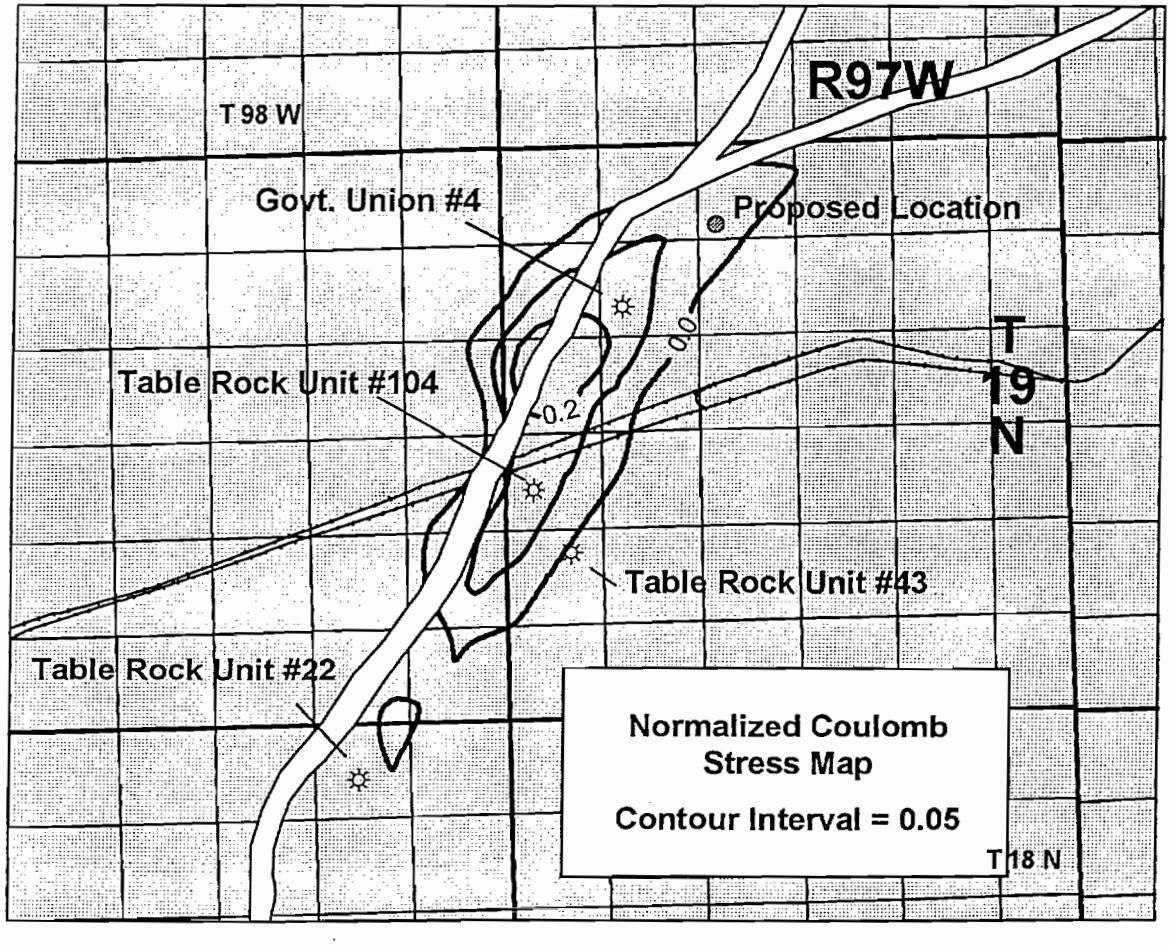
Govt. Union #4 produces 6,000 mcf, Table Rock #104 IP'd at 4,300 mcf and currently produces at 300 mcf. Initial tests of Table Rock Units #22 and #43 were discouraging and the wells are shut-in.



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.
- The Rock Island 4H location is at the northeastern extent of the stress concentration.
- Predicted shear fracture orientations are N27W and N87W.

Task 2: Detailed Structural Analysis

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

- A local area of study around Rock Island 4H location.
- Depth-migrate the corresponding 3-D seismic data volume for better definition of structure.
- Map all small faults using coherency filter to enhance identification.
- Rerun stress model to capture small perturbations and identify local areas of shear fracture occurrence that may impact of offset well location(s).

Prospect Delineation

The steps necessary for a prospect delineation at Table Rock:

A. Characterizing Natural Fractures in the Frontier Fm.
   - Examine Rock Island 4H core.

B. Fault Mapping using 3-D Seismic Data
   - Post-stack depth-conversion of 3D data.
   - Coherency processing for fault identification.
   - Map fault geometry for input to stress model.

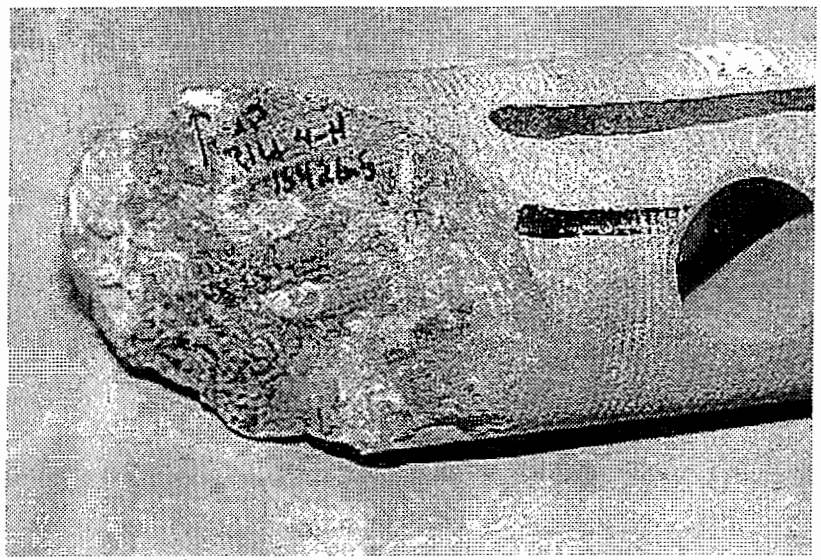
C. Predicting Fault-Related Natural Fractures
   - Assemble fault geometry and displacements.
   - Determine area(s) of enhanced natural fracturing based on geomechanical model.

Rock Island 4H Core

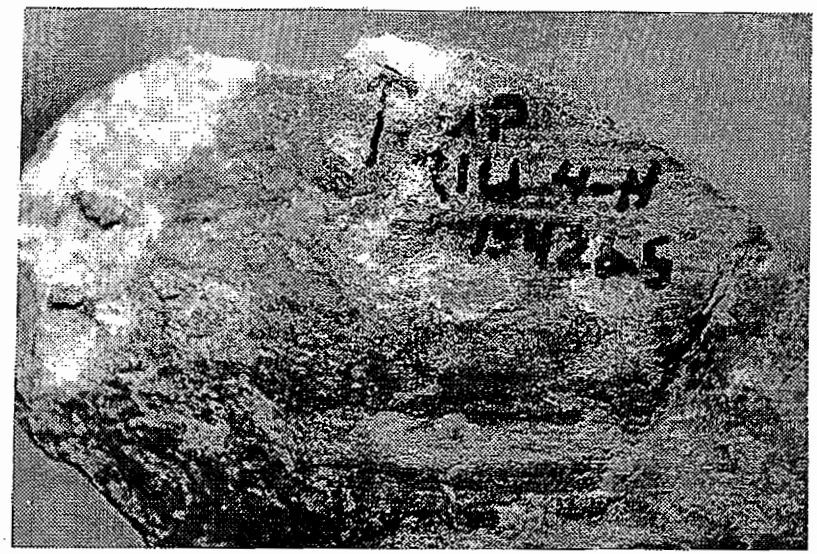
- Approximately 80 natural fractures occur in 78 feet of near-horizontal core taken from the Rock Island 4H well.
  - No consistent fracture spacing
  - Two orientations, EW, NNW with the EW set dominating.
  - About a third of the fractures show oblique right-lateral shear.
  - EW fractures occurred first and were reactivated during thrusting as sheared fractures.

Rock Island 4H Core

Sheared fracture in Rock Island 4H core.



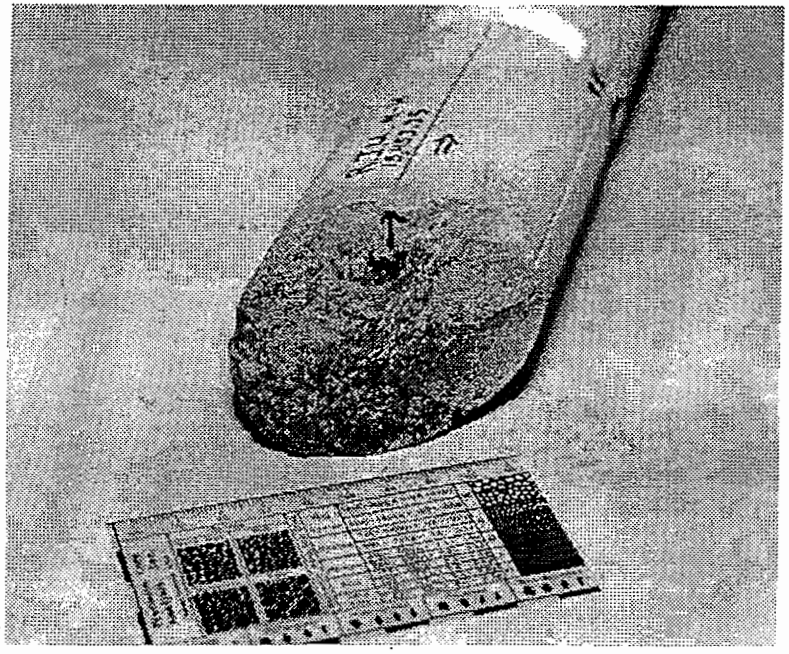
Fracture is continuous and completely cuts core.



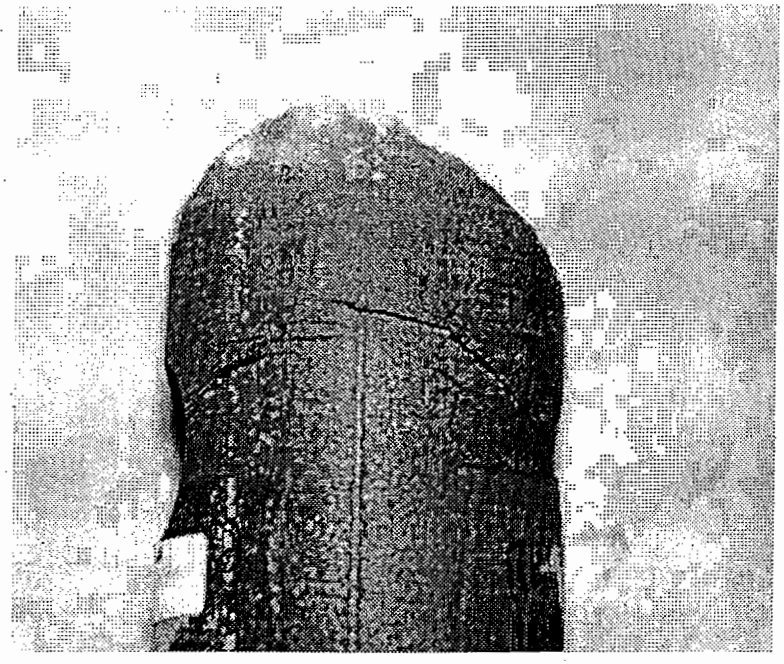
Note near horizontal rake of slickensides.

Rock Island 4H Core

Extensional fractures in Rock Island 4H core.



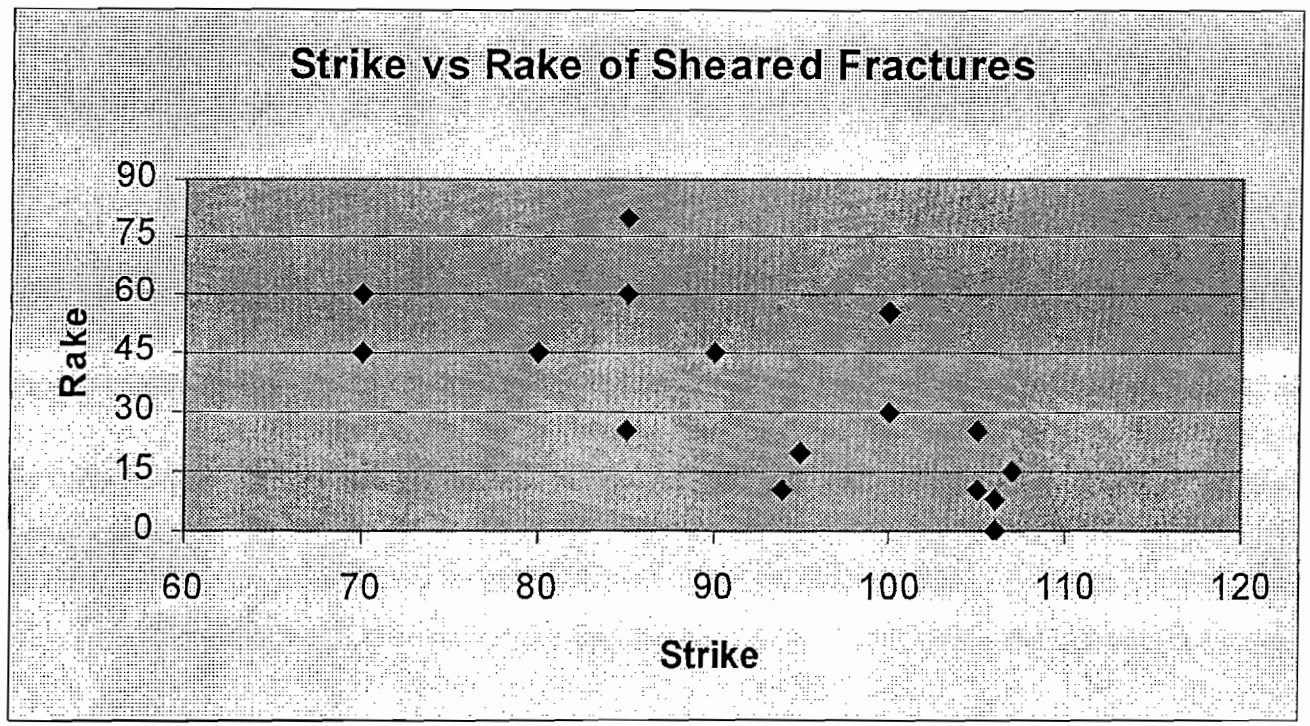
Fracture breaks down and does not completely transect core.



Note breakdown that implies fracture termination.

Rock Island 4H Core

- The sheared fractures are oriented N80W with rakes indicating dominantly strike-slip motion.
- Rake increases (more reverse component) as sheared fractures trend more NE indicating WNW oriented stress regime.



Comparison of Fracture History in Frontier Cores

Well	Production	EW Fractures	NS Fractures	Bitumen & Mineralization	Sheared Fractures
Govt. Union #4	6 mmcf/day	X	X	X	X
Frewen Deep #4	dry	X	X	X	
Table Rock 4H	12-20 mmcf/day	X	X	X	X

- The only difference between productive wells and dry hole is the presence of sheared fractures.
- This relationship highlights the dependence of the play on <u>fault-related natural fractures</u>.

3-D Seismic: Fault Mapping

Analysis objectives:

1) To provide detailed fault geometry in spatial coordinates for use in geomechanical model,

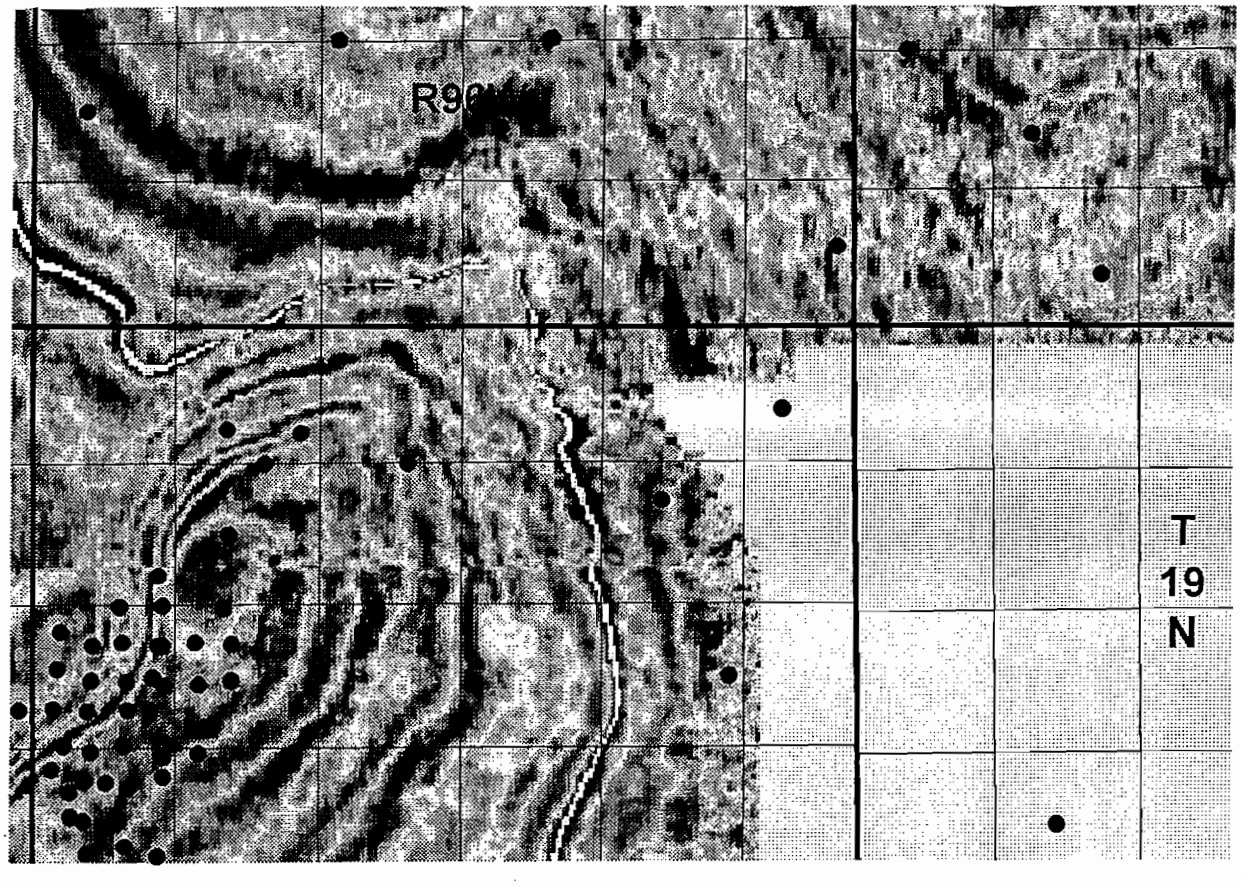
2) To identify local fault-related natural fracture clusters that may be considered prospective for offset of Rock Island 4H and extension of Frontier play.

3-D Seismic: Fault Mapping

- A full 3D data set was extracted around the horizontal drilling location to map the local fault geometry.
  - Depth-converted to map faults in space rather than time.
  - Used coherency processing to optimize fault identification.
- Local geometry of fault systems permit the prediction of local natural fracture development.

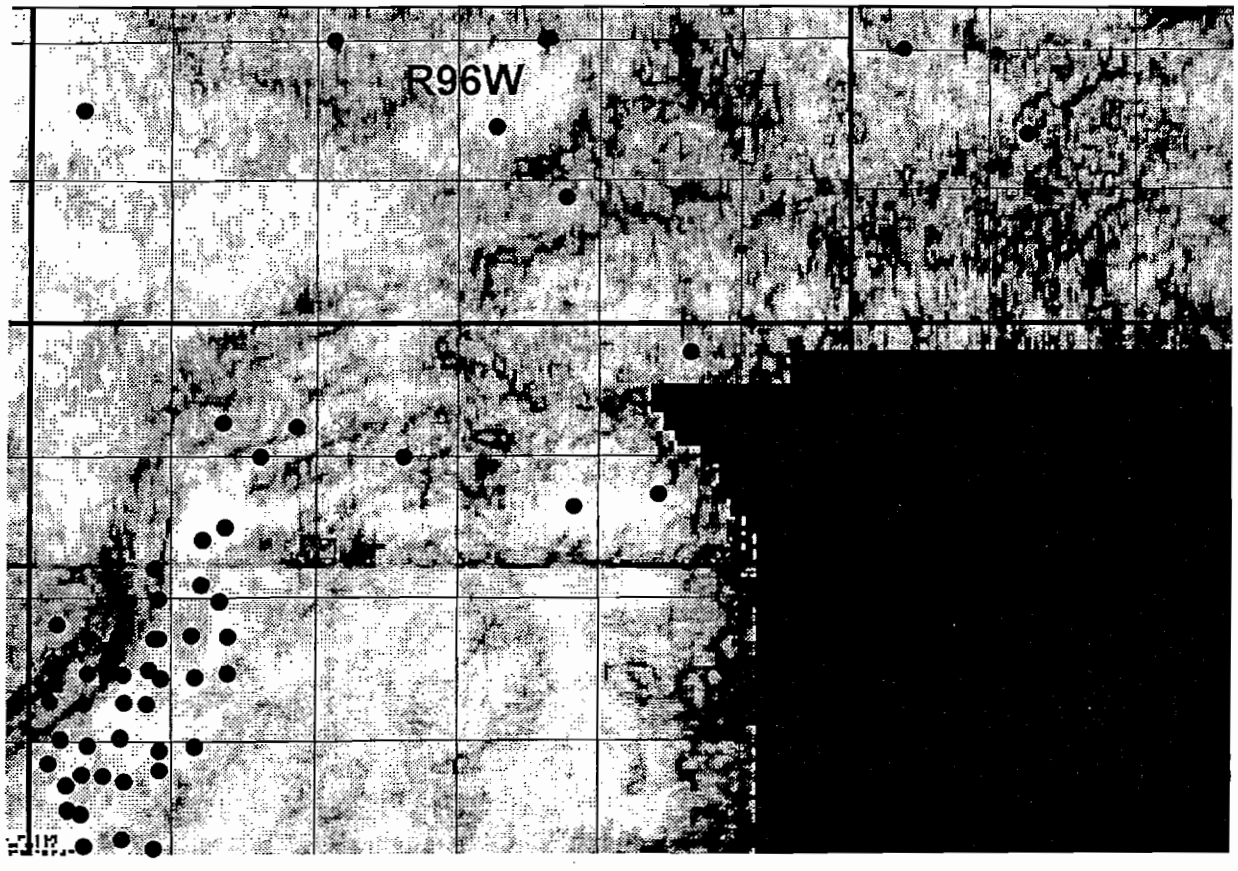
3D Seismic: Depth Slice 16,000'

Frontier horizon shown in yellow.



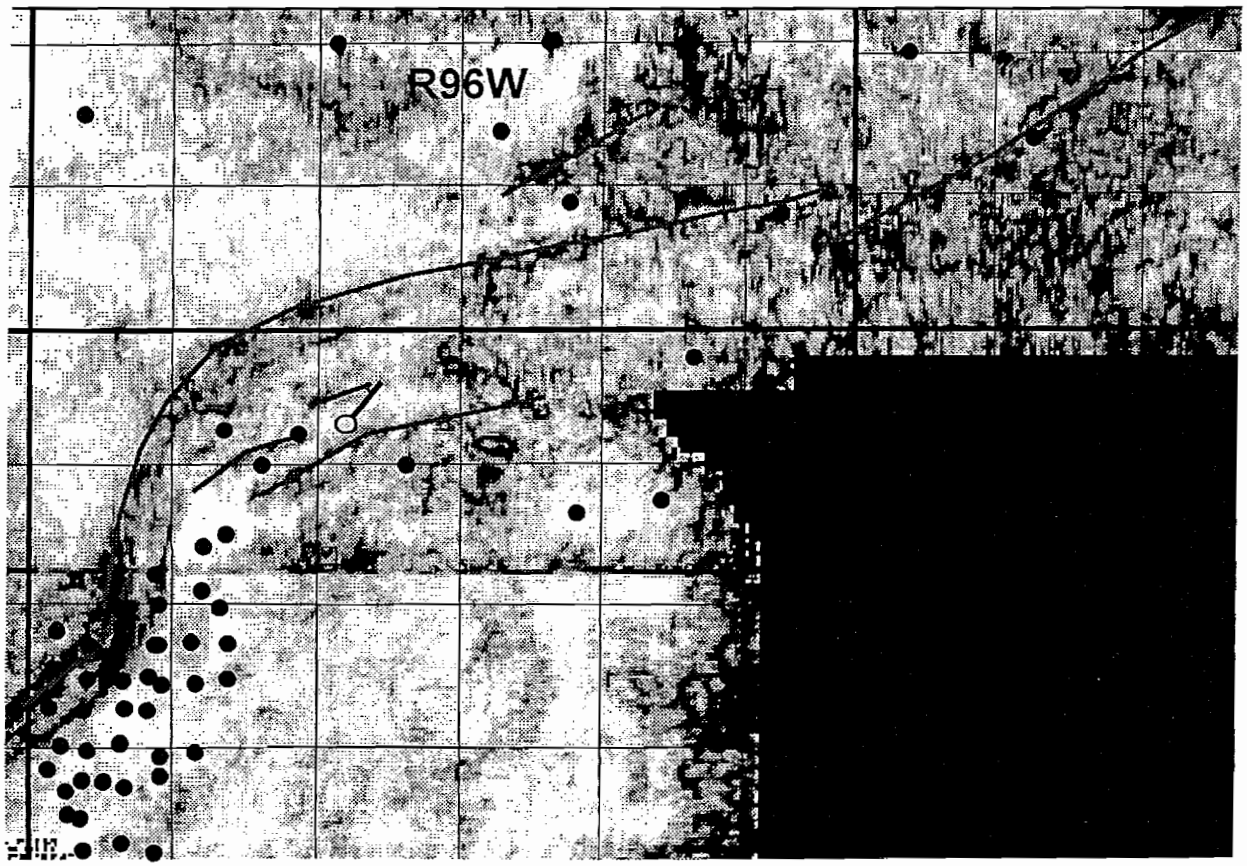
3D Seismic: Coherency Slice 16,000'

The coherency processing highlights the fault-related discontinuities in the data.



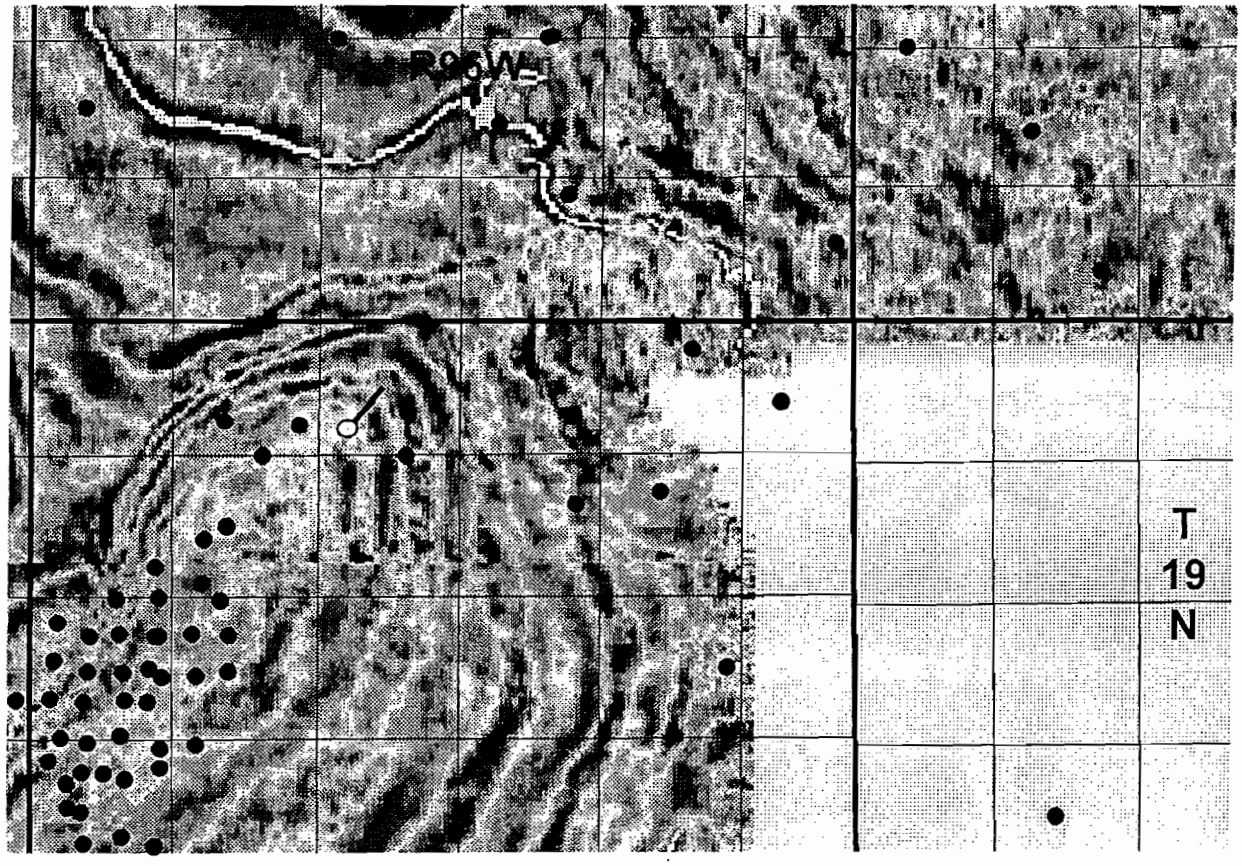
3D Seismic: Fault Mapping

Subtle faults and complex geometry of the main thrust and strike-slip system are revealed after coherency filtering.



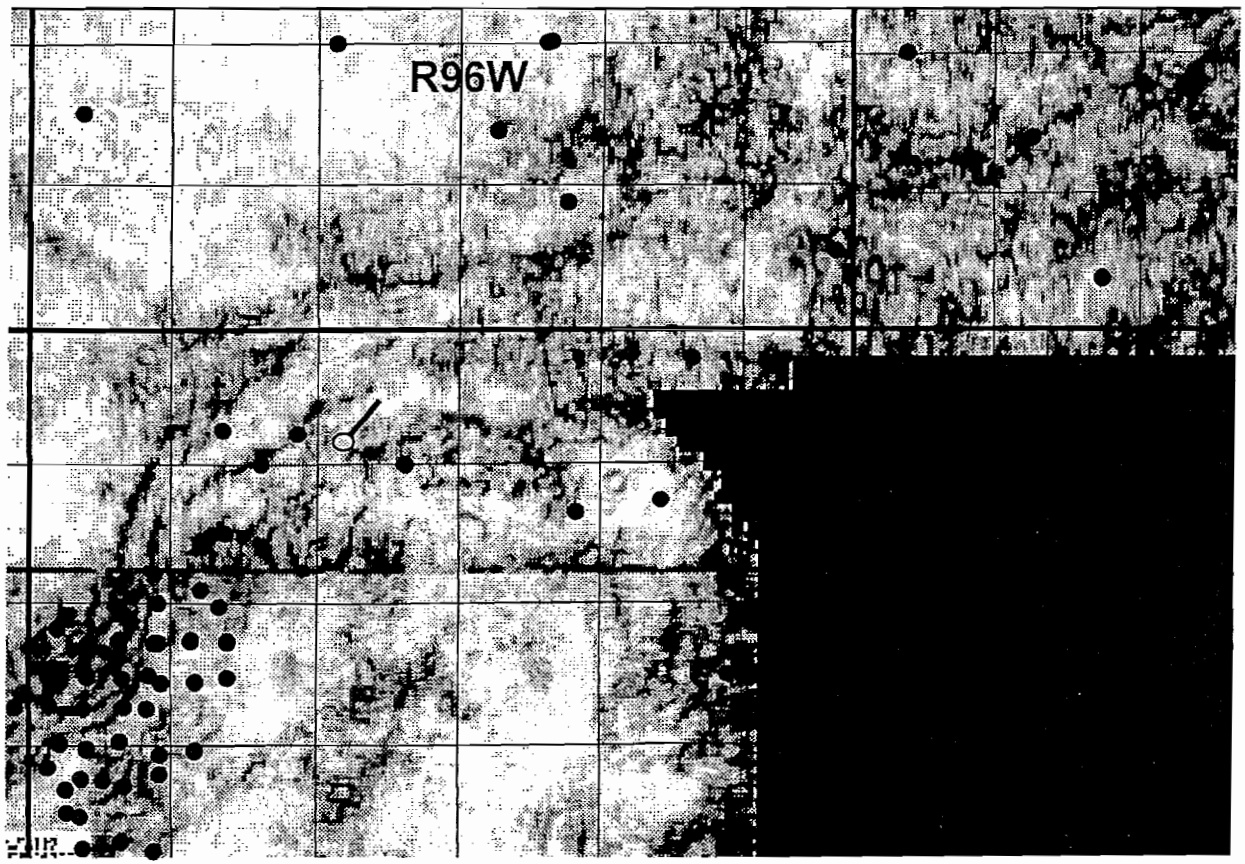
3D Seismic: Depth Slice 16,500'

A depth-slice further below the Frontier shows consistency of structure.



3D Seismic: Coherency Slice 16,500'

Again, the faults are detected by the coherency processing.



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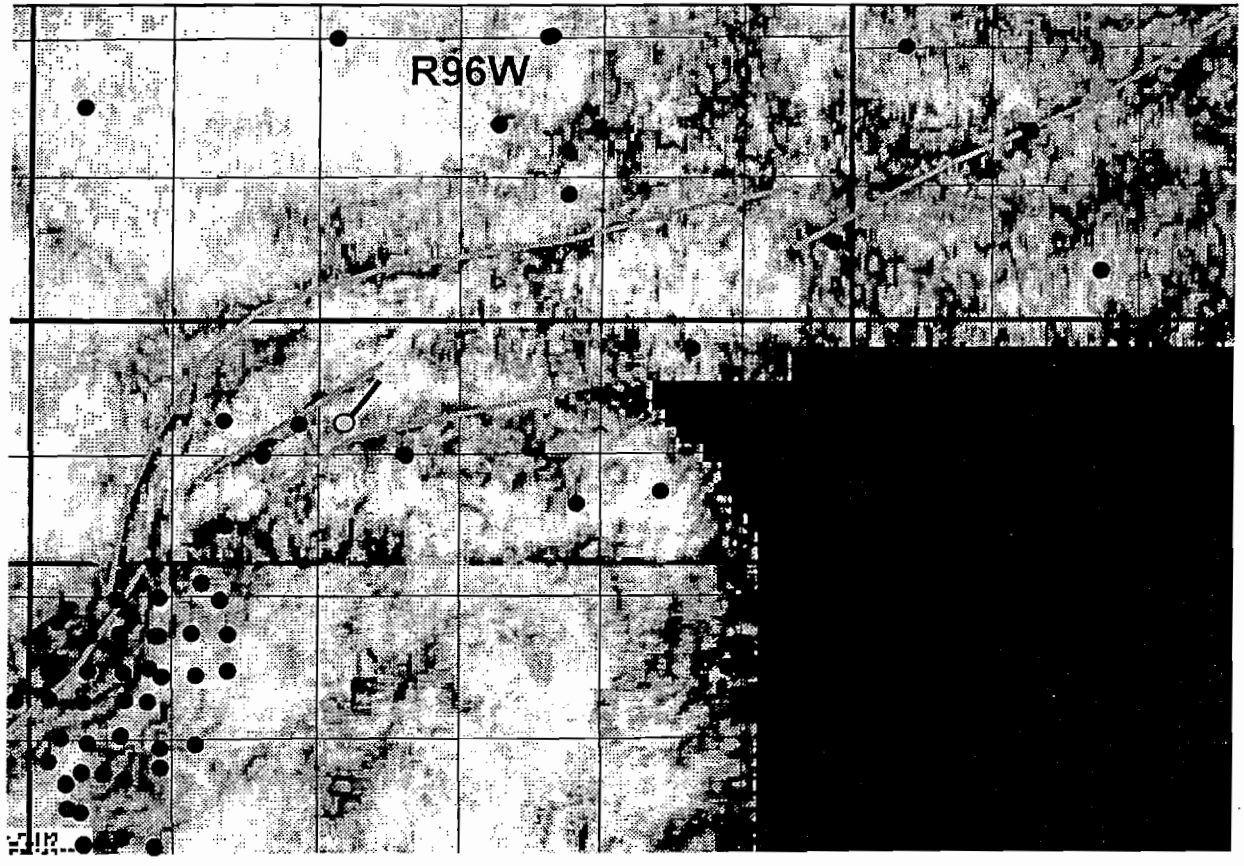
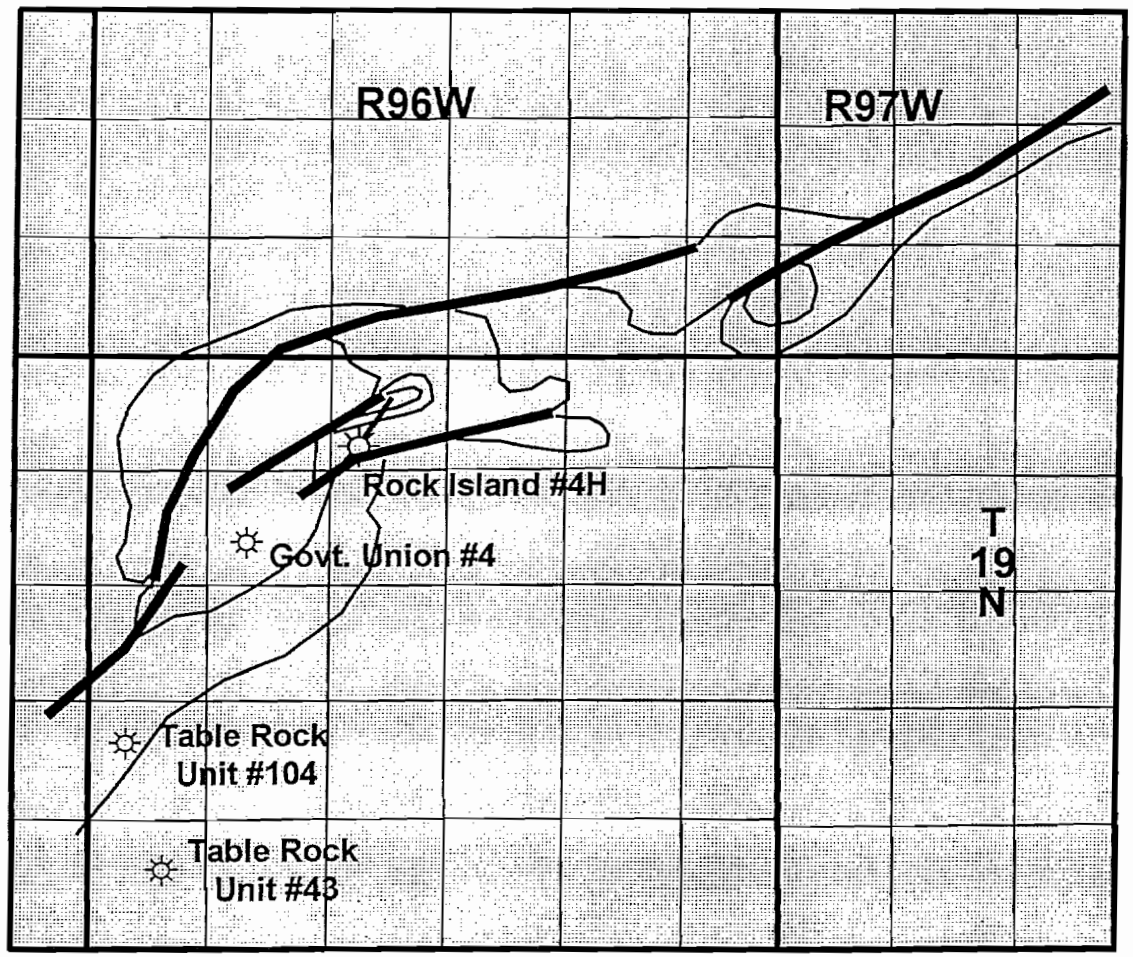
3D Seismic: Fault Mapping

The fault mapping of the deeper slices show a consistent geometry to the fault systems.



Natural Fracture Prediction: Geomechanical Model Results

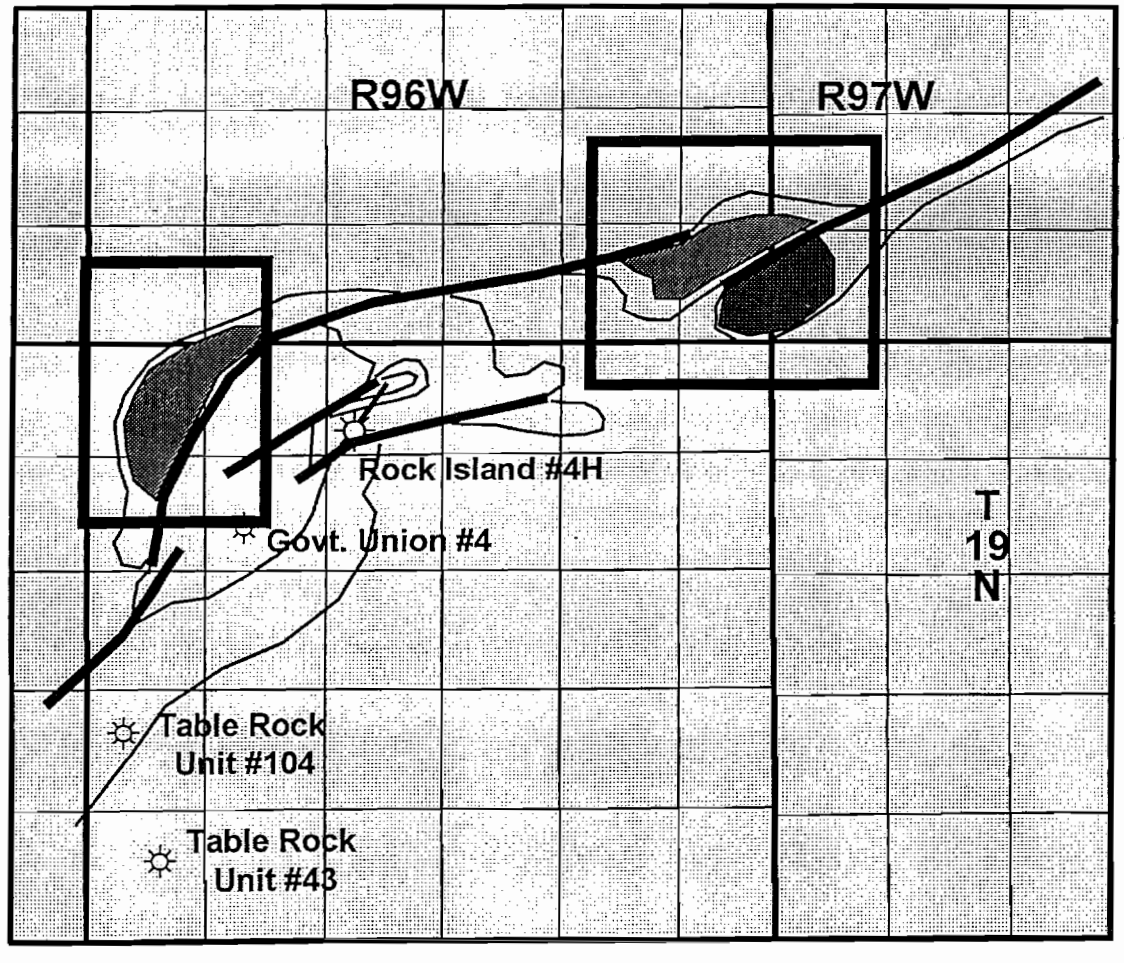
The Rock Island 4H occupies an area between two small faults and may have hit a zone of enhanced tensional failure.



Natural Fracture Prediction: Geomechanical Model Results

Other possible areas for offset and step-out in the Frontier play include:

- Region in Sec. 36 of T20N, R96W where both the tensional and shear failure could occur.
- Region west of the main thrust where tensional failure is expected in the down-thrown block.



Summary of Prospect Delineation at Table Rock

- Detailed analysis of 3D data, aided by coherency processing, reveals a complex fault geometry:
  - small northeast-trending faults in the vicinity of Table Rock horizontal well.
- Geomechanical modelling this more complex system indicates a more diverse and expanded potential for naturally fractured "sweet spots"
  - It is predicted that the Table Rock horizontal well will encounter an area of increase probability for both tensile and sheared fractures.
  - Other prospects are indicated such as Section 36 of T20N, R97W

Conclusions

- Productive natural fractures in the Frontier Fm are controlled by local structural complexity such as faults (i.e. fault-related natural fractures).
- Prospect delineation stage requires detailed natural fracture characterization, fault mapping using 3D seismic, and geomechanical modelling.
- Complexity of the play is retained at the well-bore scale
  - A single vertical drilling does not necessarily test the play
  - Horizontal drilling required to reach fault-related natural fracture clusters