# SESSION 3A

# WESTERN GAS SANDS

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## ABSTRACT

Western Gas research is a multidisciplinary effort supporting the development of low-permeability "tight" gas reservoirs in the western United States. The purpose is to determine the economical risks and technical feasibility of economically producing natural gas from tight formations. The approach for realizing this purpose consists of conducting laboratory and field research as well as encouraging industrial efforts to develop the necessary understanding, technologies, and strategies. Two broad objectives have been defined: to reduce the uncertainty of the reservoir production potential through an increased understanding of the resource and to improve the extraction technology so that industry can assume development of the resource. Currently, Western Gas research pursues the objectives through (1) basin-wide resource definition and development of reserves through fundamental geologic research and integration; (2) supporting generic research on reservoir properties and performance, geoscience-oriented research, and the maintenance of a predictive capability in reservoir behavior analysis and stimulation design and performance evaluation; and (3) development of production and extraction technologies through field research. Slant hole completion research will use the well-characterized field laboratory setting at the multiwell site in western Colorado. Concurrently, production technology developed earlier at the site is being extrapolated across the Piceance and Uinta basins by means of production and reservoir pattern analysis and verification tests in wells of opportunity.

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GAS RESOURCE ASSESSMENTS--GREATER GREEN RIVER BASIN, WYOMING, COLORADO, AND UTAH

1. <u>CONTRACT NUMBER:</u> DE-AI21-83-MC20422

<u>CONTRACTOR:</u> U.S. Geological Survey
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Lakewood, Colorado 80225
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<u>CONTRACT PROJECT MANAGER:</u> Ben E. Law

<u>PRINCIPAL INVESTIGATORS:</u> B.E. Law
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V.F. Nuccio
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<u>METC PROJECT MANAGER:</u> Karl-Heinz Frohne

<u>CONTRACT PERIOD OF PERFORMANCE:</u> October 1, 1987 to September 30, 1988

2. <u>SCHEDULE/MILESTONES:</u>

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                     |<-- 1987 -->|<--------------- 1988------------->|
                     O    N    D  J  F    M    A    M    J    J    A  S
                     |    |    |  |  |    |    |    |    |    |    |  |
---------------------------------------------------------------------------
Origin of gas        Δ-------------|-----------------------Δ
 in Lewis Shale
 reservoirs

Fracture analysis              Δ---|------------------------------------Δ

Porosity-            Δ-------------|-----------------------Δ
 permeability of
 Almond Formation

Thermal history      Δ-------------|-----------------------Δ
 of Moxa arch
 area

Sedimentology/                       Δ------------------------------Δ
 petrology of
 Ericson Sandstone

Resource             Δ-------------|------------------------------------Δ
 assessment

Geologic summary               Δ---|------------------------------------Δ
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## 3. OBJECTIVES:

The current major objectives of this project are to do basic and applied geologic research leading to assessments of in-place gas resources in the primary tight gas sandstone basins.

USGS gas resource assessments in the Northern Great Plains and the Piceance basin have been made and published, and the assessment of gas-in-place in the Greater Green River basin (GGRB) has recently been completed. The estimates of gas-in-place in the GGRB are substantially higher than previous estimates because of the development of a geologic model for these gas accumulations. Also, previous estimates were more concerned with near-term potential development and, understandably, concentrated on "sweet spots" in the tight gas plays.

The USGS methodology, scope of investigation, and gas estimates are directed toward the long-term development of the resource and its future significance to the Nation's energy base from now until the ultimate depletion of the resource.

The ongoing research is currently focused on the documentation and publication of the Greater Green River resource assessment studies. The gas reservoirs in the basin were subdivided into five stratigraphic intervals, or plays, with similar internal characteristics. Thick sequences of gas-saturated rocks (sandstones, siltstones, shales, and coals) were mapped. Some of these sequences are more than 5,000-ft (1,525-m) thick.

## 4. BACKGROUND STATEMENT:

Very large gas resources are contained in low-permeability Cretaceous and lower Tertiary rocks of the Greater Green River basin in Wyoming, Utah, and Colorado (Fig. 1). Commonly these gas accumulations are overpressured and occur in the deeper parts of the basin downdip from normal-pressured water-bearing reservoirs (Fig. 2).

Similar strata are present in the Uinta and Piceance basins in Utah and Colorado. An assessment of in-place and recoverable gas has been completed by the USGS in the Piceance basin (Johnson and others, 1988).

## 5. PROJECT DESCRIPTION:

A wide variety of methods are being used to geologically characterize low-permeability sandstone reservoirs and resolve resource assessment and recovery technology problems. These methods include surface and subsurface stratigraphic studies, paleoenvironmental interpretation, micropaleontologic analysis, organic geochemical and thermal maturation studies, origin of gases, subsurface-pressure mapping, core-to-well-log correlation, and analysis of regional natural-fracture trends. The reservoir rocks are being characterized using optical petrography, scanning-electron microscopy, X-ray diffraction, and electron probe.

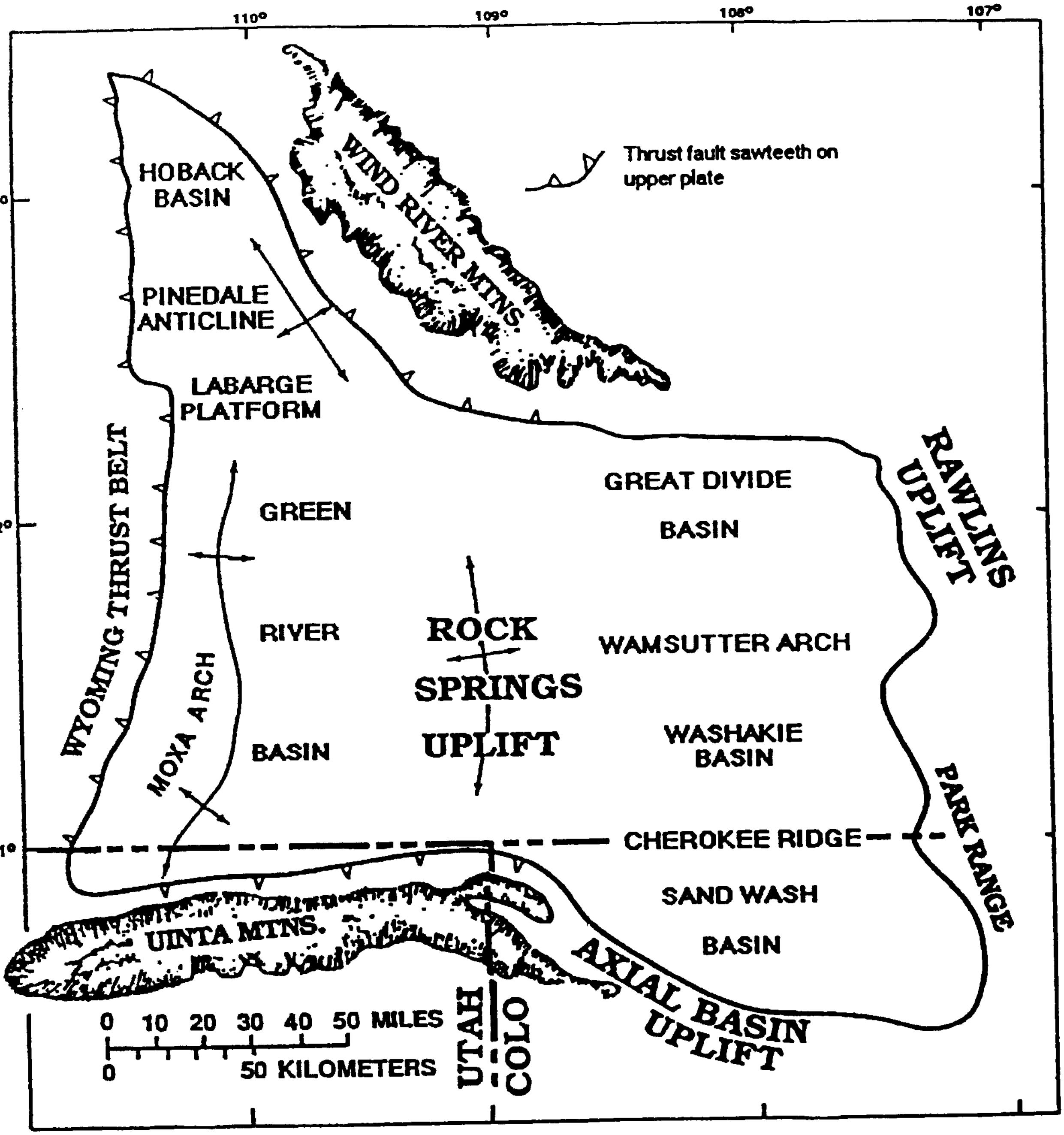


Figure 1.--Map of Greater Green River basin showing major structural elements and subbasins.

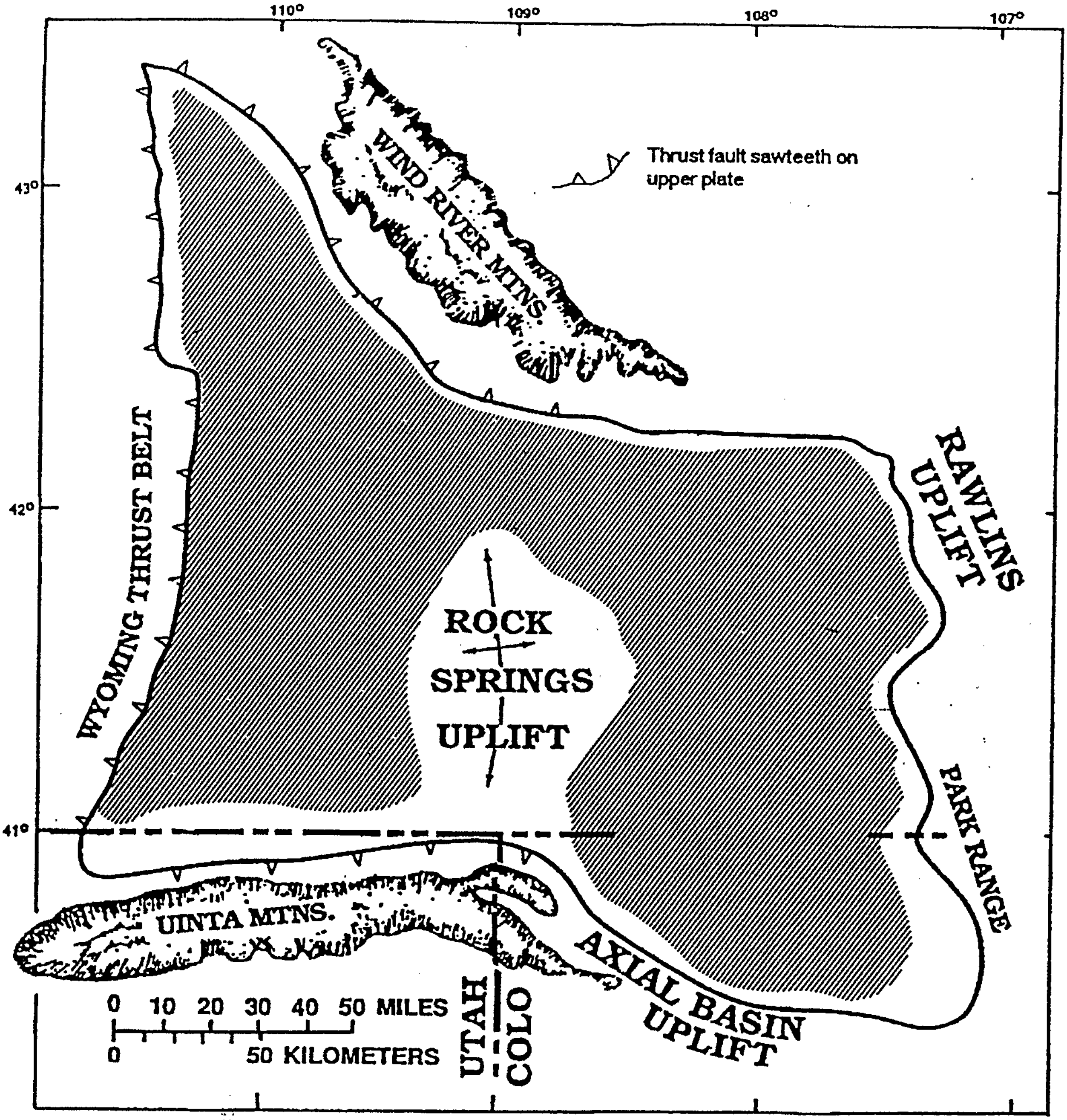


Figure 2.--Areal extent of overpressured Cretaceous and Tertiary rocks (patterned area) in the Greater Green River basin.

Other studies include analysis of stable isotopes of oxygen and carbon, fission-track annealing, and fluid inclusions. These studies are conducted in order to address different aspects of low-permeability gas reservoirs--such as the temporal relationships between reservoir diagenesis, gas generation, and gas accumulation.

## 6. RESULTS AND ACCOMPLISHMENTS:

A bibliography of publications prepared by the USGS in cooperation with DOE has been compiled and will be published by DOE in the first half of 1989. This bibliography includes more than 260 published formal research papers and does not include any administrative reports.

An assessment of gas-in-place in low-permeability reservoirs in the Greater Green River basin has been completed. The stratigraphic sequence in which these reservoirs occur is as much as 14,000-ft (4,267-m) thick and includes the Lower Cretaceous Cloverly Formation through the lower Tertiary Fort Union Formation. Correlations of these stratigraphic units within the Greater Green River basin are shown in Figure 3.

The generation and accumulation of thermogenic gas in these low-permeability reservoirs, at rates greater than it is lost, causes fluid (gas) pressure to rise above regional hydrostatic pressure. Thus, in the study area, all overpressured reservoirs are gas bearing. The gas-bearing overpressured sandstone reservoirs occupy the deeper parts of the basin, down-dip from water-bearing normal-pressured reservoirs. Structural and stratigraphic trapping aspects in these unconventional reservoirs are not as important as in conventional reservoirs; the top of overpressuring cuts across structural and stratigraphic boundaries. The source of the gas is predominantly type III organic matter in the interbedded coal and carbonaceous lithologies and type II and III organic matter in the interbedded marine shales.

For resource appraisal purposes, the gas-bearing interval was subdivided into five stratigraphic plays and the volume of gas-in-place for each play was estimated using a probabilistic analysis. Only sandstones thicker than ten feet were included in the analysis; siltstone and shale strata and normally-pressured "transition zones" where interbedded gas and water-bearing reservoirs occur were excluded. The estimate of total gas-in-place resource of these plays ranges from 3,611 to 6,837 tcf (trillion cubic feet) with 5,063 tcf as the mean estimate. Table 1 shows the estimates of gas resources for each stratigraphic play.

Because of additional uncertainty related to economic recovery factors, estimation of recoverable volumes is inherently less precise than estimation of in-place volumes. Two of the most important factors influencing the volume of recoverable gas are price and technology. Therefore, recoverable gas was estimated for each play under two cases: (1) state-of-the-art current technology, with a gas price of five dollars per thousand cubic feet, and (2) future technology, with no

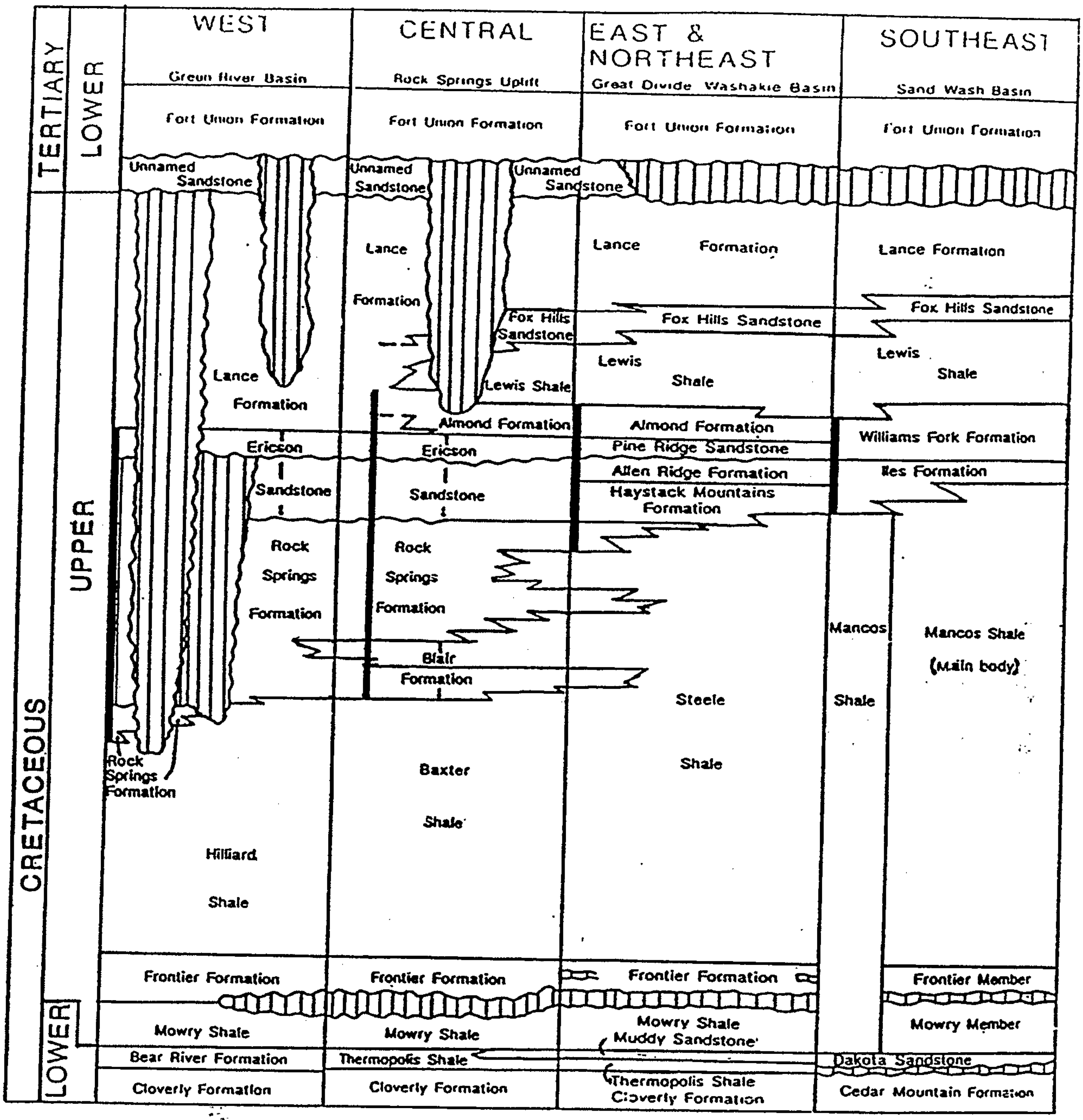


Figure 3. Generalized correlation chart of Cretaceous and lower Tertiary stratigraphic units in the Greater Green River basin. Heavy black bar shows limits of Mesaverde Group in various areas. Diagram represents general age and facies relationships and not relative rock thickness.

Table 1.--Greater Green River basin estimates of tight gas resources in trillions of cubic feet

| Play | In-Place | | | Recoverable: Current Technology[1] | | | Recoverable: Future Technology[2] | | |
|---|---|---|---|---|---|---|---|---|---|
| | Low $F_{95}$ | High $F_5$ | Mean | Low $F_{95}$ | High $F_5$ | Mean | Low $F_{95}$ | High $F_5$ | Mean |
| Fort Union | 70 | 127 | 96 | 0.4 | 2.3 | 1.1 | 3.7 | 15.5 | 8.3 |
| Lance-Fox Hills | 470 | 1009 | 707 | 3.1 | 17.2 | 8.4 | 26.2 | 117.5 | 61.5 |
| Lewis | 428 | 835 | 610 | 6.2 | 38.4 | 18.0 | 38.5 | 147.1 | 81.8 |
| Mesaverde | 2329 | 4607 | 3347 | 13.8 | 89.9 | 41.4 | 100.8 | 538.6 | 265.2 |
| Cloverly-Frontier | 208 | 423 | 304 | 1.3 | 7.7 | 3.7 | 7.9 | 29.3 | 16.4 |
| Aggregation of all five plays | 3611 | 6837 | 5063 | 27 | 148 | 73 | 189 | 816 | 433 |
| Aggregation of first four plays | 3383 | 6445 | 4760 | 26 | 141 | 69 | 180 | 789 | 417 |

[1]Current technology assumes present-day, state-of-the-art drilling and completion methods and existing well spacing and $5 per MCF (1987 dollars). The price was selected based on the assumption that this price would presently encourage economic development of the resource.

[2]Future technology assumes exotic drilling and completion methods that will maximize well and stimulation contact with the greatest feasible number of reservoirs. It assumes nondamaging communication can be made between the wellbore and the natural fractures. It also assumes very high gas prices on a par or higher than other future energy sources.

Fractiles are not additive; means are additive within round-off error.

dollar limit. For the current technology case, the estimate of total recoverable gas ranges from 27 to 148 tcf, with 73 tcf as the mean estimate (Table 1). For the future technology case, the estimate of total recoverable gas ranges from 189 to 816 tcf, with 433 tcf as the mean estimate (Table 1).

7. **FUTURE WORK:**

Future work and in-progress work includes compiling and analyzing geologic data in the Uinta basin in Utah in preparation for a resource assessment. A report documenting the results of the Greater Green River basin tight gas resource assessment is in preparation.

8. **REPORTS PUBLISHED IN 1988:**


Johnson, R.C., Crovelli, R.A., Spencer, C.W., and Mast, R.F., 1988, Assessment of gas resources in low-permeability sandstones of Upper Cretaceous Mesaverde Group, Piceance Basin, Colorado: American Association of Petroleum Geologists Bulletin, v. 72, no. 2, p. 202.

Johnson, R.C., Crovelli, R.A., Spencer, C.W., and Mast, R.F., 1988, An assessment of gas resources in low-permeability sandstones of Upper Cretaceous Mesaverde Group, Piceance Basin, Colorado, in Carter, L.M.H., ed., USGS research on energy resources--1988; Program and Abstracts: U.S. Geological Survey Circular 1025, p. 23-24.

Law, B.E., and Clayton, J.L., 1988, The role of thermal history in the preservation of oil at the south end of the Moxa arch, Utah and Wyoming--Implications for the oil potential in the southern Green River basin, in Carter, L.M.H., ed., USGS research on energy resources--1988; Program and Abstracts: U.S. Geological Survey Circular 1025, p. 27.

Law, B.E., and Spencer, C.W., 1988, Tight gas reservoirs, in Magoon, L.B., ed., Petroleum systems of the United States: U.S. Geological Survey Bulletin 1870, p. 44-46.

Lickus, M.R., and Law, B.E., 1988, Structure contour map of the Greater Green River Basin, Wyoming, Colorado, and Utah: U.S. Geological Survey Miscellaneous Field Studies Map MF-2031.

Nuccio, V.F., and Johnson, R.C., 1988, Surface vitrinite reflectance map of the Uinta, Piceance and Eagle basins area, Utah and Colorado: U.S. Geological Survey Miscellaneous Field Study Map, MF-2008-B, one plate, 19 p.

Schmoker, J.W., and Gautier, D.L., 1988, Sandstone porosity as a function of thermal maturity--An approach to porosity comparisons and prediction: American Association of Petroleum Geologists Bulletin, v. 72, no. 7, p. 880.

Spencer, C.W., 1988, Abnormally high- and low-pressured gas reservoirs--Examples from Rocky Mountain region, in Carter, L.M.H., ed., USGS research on energy resources--1988; Program and Abstracts: U.S. Geological Survey Circular 1025, p. 58.

Spencer, C.W., and Law, B.E., 1988, Unconventional resources--Western tight gas reservoirs, in National assessment of undiscovered conventional oil and gas resources, USGS-MMS, working paper: U.S. Geological Survey Open-File Report 88-373, p. 480-500.

MULTIWELL EXPERIMENT

1. CONTRACT NUMBER: DE-AC04-76DP00789

CONTRACTOR: Sandia National Laboratories
Geotechnology Division 6253
Albuquerque, NM 87185

CONTRACTOR PROJECT MANAGER: Dr. David A. Northrop

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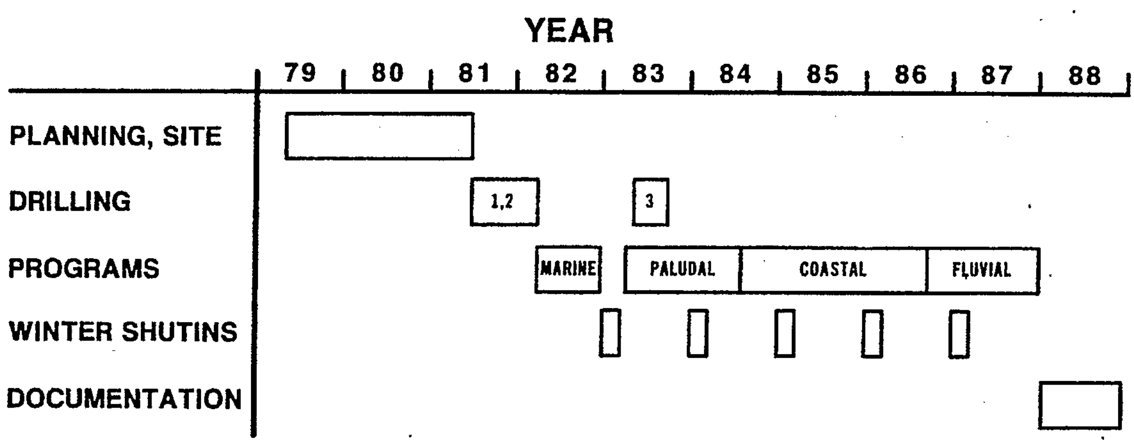
Dr. Billy J. Thorne
Mr. Paul T. Branagan, CER Corporation

METC PROJECT MANAGER: Karl-Heinz Frohne

PERIOD OF PERFORMANCE: October 1, 1980-September 30, 1988

2. SCHEDULE/MILESTONES:




3. OBJECTIVES:

The Multiwell Experiment was a research-oriented field laboratory. Its overall objectives were to characterize lenticular, low-permeability gas reservoirs and to develop technology for their production. Its wide range of activities and its wealth of data provided a unique, in-depth look at a significant natural gas resource in the western United States.

4. BACKGROUND STATEMENT:

For a number of years the United States government has engaged in research to enhance gas recovery from unconventional reservoirs such as organically rich, fractured shale and discontinuous, lenticular, tight sandstones. Although large quantities of natural gas are trapped in these formations, the permeabilities are too low to permit economic recovery by conventional technology. In the western United States, the Greater Green River, Piceance, Wind River, and Uinta basins have been identified as containing significant amounts of gas in thick sections of lenticular sands. The National Petroleum Council's 1980 study has appraised these four basins to hold a maximum of 136 TCF (4 $Tm^3$) of recoverable gas in lenticular reservoirs. This sizable resource was investigated by the U.S. Department of Energy (DOE) in the Piceance basin of western Colorado, where a field laboratory was constructed that contained three closely spaced wells penetrating the lenticular Mesaverde Formation.

Massive hydraulic fracturing has increased gas production from tight reservoirs, but its performance in lenticular formations has been unpredictable. This results from the poor definition of reservoir properties and sizes, inadequate understanding of the factors controlling fracture propagation and proppant transport, limited ability to measure, describe, or evaluate the created fracture, and uncertainty as to the relationship between stimulation design variables (fluids, proppants, pumping rates) and the resulting fracture. These difficulties are compounded in the lenticular formations by complex lithologies, variability in lens sizes, and uncertainty of whether multiple lenses, some remote from the wellbore, can be stimulated by a common treatment.

Previous experiments focused on gas production and stimulation and there was insufficient information to characterize the reservoir. Further, well-test times were short because of production schedules, and also stimulation diagnostics were not applied. The intent of the Multiwell Experiment was to obtain sufficient data to characterize the reservoir, the stimulation, and the production mechanisms, and thus resolve the uncertainties surrounding this resource.

5. PROJECT DESCRIPTION:

This field laboratory was at a site in the east-central Piceance basin, about 7 mi southwest of Rifle, Colorado, where the Mesaverde Formation lies at a depth of 4000-8250 ft. This interval contains different, distinct reservoir types depending upon their depositional environments. These different zones served as the focus of the various testing and stimulation programs. Field work began in late 1981 and continued through December 1987.

One key to the Multiwell Experiment was three closely spaced wells. Their 110-215 ft separation at depth is less than the nominal dimensions of the lenses in the area. Core, log, well testing, and well-to-well seismic data provided a far better definition of the geological setting than had been available previously. Over 4100 ft of core was taken from the wells through the thick Mesaverde Formation. Comprehensive logging and core analysis programs were conducted. The closely spaced wells also allowed interference and tracer tests to obtain in situ reservoir parameters. The vertical variation of in situ stress throughout the intervals of interest was measured. A series of stimulation experiments was conducted in one well and the other two wells were used as observation wells for improved fracture diagnostics, well testing, and stress testing.

Another key was the synergism resulting from a broad spectrum of activities: geophysical surveys, sedimentological studies, core and log analyses, well testing, in situ stress determination, stimulation, fracture diagnostics, and reservoir analyses. The results from the various activities defined the reservoir and the hydraulic fracture. These, in turn, defined the net pay stimulated: the intersection of a hydraulic fracture of known geometry with a reservoir of known morphology and properties. These definitions were further enhanced by the fact that most data came from closely spaced wells. Thus, spatial variations in reservoir properties were quantified

6. RESULTS/ACCOMPLISHMENTS:

The Multiwell Experiment has been completed. Activities and experiments were conducted in each of the four major depositional environments as summarized in Figure 1. The following is a summary of the accomplishments, results, and contributions from this eight-year program. The references list the final reports for the project. The Northrop and Frohne (1988) paper presents a bibliography of the nearly 100 papers resulting from the Multiwell Experiment.

## MULTIWELL EXPERIMENT ACTIVITY SUMMARY

| Interval | | Well Tests | Stimulation | Other |
|---|---|---|---|---|
| Fluvial | E | Interference | $N_2$ Foam Frac | Breakdown Tests |
| | C | Single Well | - | Minifracs (2), Altered Stress |
| | B | Interference | $N_2$ Foam Frac | $N_2$ Breakdown, Tracer (Ar) |
| Coastal | Yellow | Interference | $N_2$ Frac, $N_2$ Foam Frac | Tracer ($N_2$), Reentry (6 mo.) |
| | Red | Interference | - | - |
| Paludal | 3,4 | Interference | HPG Frac | Reentry (18 mo.) |
| | 2 | Single Well | - | - |
| Marine | U. Cozzette | Interference | - | - |
| | L. Cozzette | Single Well | - | - |
| | Corcoran | Single Well | - | - |

*Note: Stress tests conducted in all intervals.
Step rate and flow back tests and minifracs conducted prior to all stimulations (except coastal).

A. Significance of the Depositional Environment:

- The Mesaverde was subdivided on the basis of different depositional environments; these produced distinctly different reservoirs, each of which was the focus of MWX study.

- Depositional environment controls reservoir size, morphology, and internal heterogeneity:

| | Depositional Environment | Reservoir Width (ft) | Internal Heterogeneity |
|---|---|---|---|
| Marine | Shoreline/marine | >10,000 | Low |
| Paludal | Distributary Channel and Splay | 150-500 | Moderate |
| Coastal | | < 1,000 | Moderate |
| Fluvial | Meander Belt | 1,000-2,500 | High |

- Developed and confirmed a technique to estimate reservoir size from single well data which is based upon empirical relationships derived for similar environments.

- Demonstrated that the depositional environment controls reservoir properties including features of the natural fracture system.

B. Important Role of Natural Fractures

- Characterized natural fracture systems and styles over the Mesaverde. Fractures come in a wide range of sizes (width, length, and height) and their frequency varies as a function of depth. The highest frequency occurs in the middle fluvial section.

- In all zones, reservoir permeabilities as measured in well tests are one to three orders of magnitude greater than matrix permeabilities as measured in core under restored reservoir conditions of stress and saturation. Measured permeability along mineralized fractures is also greater than matrix permeability. Thus, even tight fractures dominate permeability in submicrodarcy rock.

- Derived a unidirectional, natural fracture model which is consistent with outcrop, core, and well-test data. This regional system results from moderate horizontal compressive tectonic stress acting on a rock under high pore pressures. At various depths, a second fracture system is superimposed, resulting in improved reservoir performance.

- Modeled fracture origin by (1) developing a paleostress history from burial, property, and tectonic histories, (2) estimating rock properties under conditions suggested by the paleostress history, and (3) applying rock failure criteria to establish time and mode of fracturing. While preliminary, this approach reproduced the unidirectional, regional fracture system described above.

C. Improved Core and Log Analyses

- Routine tight sandstone analyses are now available to the industry through the service industry. MWX was instrumental in the development of techniques to routinely measure permeabilities less than a microdarcy under simulated reservoir conditions.

- Laboratory studies provided new insights into damage and completion phenomena. These include the damage to the sensitive natural fracture system by water and fracturing fluids as well as determining the actual stability of polymer components under reservoir conditions.

- An improved log analysis procedure, TITEGAS, was developed based upon the extensive MWX log and core data base. It has been applied successfully elsewhere in the Piceance Basin.

D. Measurement and Use of In Situ Stress

- MWX played a key role in the development of an anelastic strain recovery technique to measure in situ stress directions and, through a new viscoelastic modeling technique, magnitudes.

- These, along with other core, geologic, and modeling studies, predicted a hydraulic fracture azimuth of N60°-80°W for the site. This direction was confirmed in subsequent fracturing experiments.

- Refined a small volume hydraulic fracturing technique for measuring the minimum in situ stress in perforated, cased wellbores. The vertical distribution of these stresses was measured in 63 locations over a 3900 ft interval in sandstones and confining rocks; these data were used in the design and analysis of stimulation treatments and in understanding the stress-fracture-property relationships in Mesaverde reservoirs.

- Demonstrated that hydraulic fracturing can significantly increase the minimum in situ stress at an offset well. Thus, the new concept of altered stress fracturing to change the azimuth of a hydraulic fracture appears feasible.

E. Stimulation of Mesaverde Reservoirs

- The effectiveness of hydraulic fracturing appears limited, since a frac will parallel the unidirectional, anisotropic natural fracture system. Calculations show that a 100-ft frac in the orthogonal direction is as effective as a 1000-ft frac along the natural fracture system. Thus, alternative approaches such as directional drilling and altered stress fracturing may be required for effective gas recovery.

- High fracturing pressures were observed in each stimulation. Thus, damage is likely, especially to the natural fracture system, and the choice of frac fluid is very important. However, tests in the paludal zone showed that this damage was transitory: it was alleviated during an extended (18-month) shut-in.

- Derived a model to history match bottomhole pressures during foam stimulations to derive estimates of frac parameters. It is sufficiently versatile to match gas, foam, and foam and proppant stages, as well as treatment perturbations in the record.

- Identified a dual leakoff phenomenon contributing to early screenouts during hydraulic fracturing treatments in these formations. A significantly increased (50 times) leakoff occurred above a threshold pressure several hundred psi above the formation closure pressure. It was shown that the use of fine sand, increased pad volumes, and careful design will reduce the leakoff to manageable levels.

- Hydraulic fracturing of remote lenses, at least at this site, is not feasible, due to the high stresses found in the confining lithologies compared with the stresses in the sandstone reservoirs. There may be places elsewhere in the Mesaverde where contrasts are less and fracturing of remote lenses may be possible; the key point is that the stress contrasts must be measured to assess each situation.

- Borehole seismic diagnostics fielded in the observation wells determined hydraulic fracture azimuth and height, although these measurements were affected by the complex geology. Several advances in the technology (e.g., four-axis geophone array, improved electronics, location algorithms) were made.

F. Natural Gas Production

- Natural gas production is a function of depositional environment and degree of natural fracturing. This can be seen in the following summary of zones tested:

| | | PERFORATED PAY (ft) | PRODUCTION (MCFD) PREFRAC | POSTFRAC | PREFRAC (MCFD/ft) |
|---|---|---|---|---|---|
| FLUVIAL | E SAND | 30 | 70 | 240 | 2.3 |
| | C SAND | 22 | 50 | - | 2.3 |
| | B SAND | 17 | 25 | 35 | 1.5 |
| COASTAL | YELLOW | 32 | 60 | 100 | 1.9 |
| | RED | 39 | 50 | - | 1.3 |
| PALUDAL | ZONES 3, 4 | 48 | 250 | 400 | 5.2 |
| | ZONE 2 | 28 | 160 | - | 5.7 |
| MARINE | U. COZZETTE | 37 | 550 | - | 15 |
| | L. COZZETTE | 14 | >150 | - | >11 |
| | CORCORAN | 65 | >450 | - | >7 |

- Production is dominated by natural fractures. Reservoir permeabilities as measured in well tests are one to three orders of magnitude greater than matrix permeabilities. Moreover, analyses show the anisotropy of the natural fracture system is sufficient to prevent interference from being seen at the observation wells. In those few cases where interference is observed, there is evidence for a second fracture system.

- Developed a fully transient, naturally fractured reservoir simulator that includes anisotropic fracture permeability, simulated propped fracture, simulated damage/skin, transients in the matrix blocks, and three-dimensional pressure profiles.

G. Definition of Future Research Needs

- It is clear that research on understanding the reservoir is as important as developing technology for the production of that reservoir.

- Improved understanding of natural fracture systems can lead to improved gas recovery. Specific research areas include: (1) understand the origin and predict the occurrence/distribution of natural fracture systems, (2) determine their reservoir properties, especially with respect to water, and (3) derive a quantitative description which can be incorporated into a realistic reservoir simulator.

- Whereas hydraulic fracturing may still be effective in some cases, the characteristics of Mesaverde reservoirs require improved recovery technology. Ideas which should be seriously considered include: (1) specific hydraulic fracturing methods (e.g., new fluids; short, precise fracs; etc.), (2) dynamic, tailored-pulse fracturing, (3) directional drilling and deviated wellbores, (4) altered stress fracturing, and (5) multiple reservoir stimulation.

- A final important need is to extrapolate MWX understanding throughout the Piceance basin and to other basins.

7. <u>FUTURE WORK</u>:

Multiwell Experiment activities have been completed and the final documentation is almost finished (see references). The MWX site has been mothballed, but the site leases and agreements have been extended. DOE has issued an RFP to drill a deviated well at the MWX site to assess this option of improving production from Mesaverde reservoirs.

8. <u>REFERENCES</u>:

Multiwell Experiment Project Groups at Sandia National Laboratories and CER Corporation, Multiwell Experiment Final Report Series:

I. The Marine Interval of the Mesaverde Formation, Sandia National Laboratories Report, SAND87-0327, April, 1987.
II. The Paludal Interval of the Mesaverde Formation, Sandia National Laboratories Report, SAND88-1008, May 1988.
III. The Coastal Interval of the Mesaverde Formation, Sandia National Laboratories Report, SAND89-3254, March 1989.
IV. The Fluvial Interval of the Mesaverde Formation, Sandia National Laboratories Report, in review.

D. A. Northrop, Insights into Natural Gas Production from Low-Permeability Reservoirs, SPE 17706, Proceedings of the SPE Gas Technology Symposium, Dallas, TX, June 1988, pp 25-34.

D. A. Northrop and K-H. Frohne, Insights and Contributions from the Multiwell Experiment: A Field Laboratory in Tight Sandstone Reservoirs, Proceedings of the 63rd Annual Society of Petroleum Engineers Conference, Houston, TX, October 1988, volume sigma, pp 235-247.

# GEOLOGIC AND PRODUCTION CHARACTERISTICS OF THE TIGHT MESAVERDE: PICEANCE BASIN, COLORADO

1. CONTRACT NO.: DE-AC21-88MC24120

CONTRACTOR: CER Corporation
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Las Vegas, NV 89119-3701

CONTRACT PROJECT MANAGER: F. Richard Myal

PRINCIPAL INVESTIGATORS: Edwin H. Price
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Gerald C. Kukal
Paul Abadie

METC PROJECT MANAGER: K.H. Frohne

PERIOD OF PERFORMANCE: April 1, 1988 to June 1, 1989

2. SCHEDULE/MILESTONES:

- Task 1, Data Gathering and Log Analysis, is 90 percent complete and requires some additional TITEGAS log analysis which is well underway.
- Task 2, Construction of Gas Productivity Maps, is 70 percent complete and can be completed with the input from TITEGAS analysis.
- Task 3, Partitioning of the Piceance Basin, is 100 percent complete.
- Task 4, Preparation of the Basin Reports, is approximately 30 percent complete at this time.

All remaining work will be completed, and the final report delivered June 1, 1989.

3. OBJECTIVES:

The principal objectives of this investigation are to:

- advance the technology developed at MWX into other areas of the Piceance Basin and to verify the extrapolation potential of the MWX geological and engineering findings and techniques;
- reliably identify and characterize potential areas for Mesaverde gas resource development; and
- develop an optimal methodology for exploiting this gas resource.

The ultimate goal of this investigation is to transfer this technology, in whole or in part, to the industry operators (i.e., gas producers) who can implement the technology on a wide scale and significantly increase gas reserves.

4. BACKGROUND STATEMENT:

The Piceance Basin of western Colorado contains a major potential natural gas resource in the Mesaverde blanket and lenticular low permeability gas sands. The basin has been a pilot study area for government-sponsored tight gas sand research for over 20 years. This work culminated in the Multiwell Experiment, a field laboratory consisting of three closely-spaced wells, designed by the Department of Energy to study the reservoir and production characteristics of the low permeability Mesaverde gas sands near Rifle, Colorado.

5. PROJECT DESCRIPTION:

A critical comparison is being undertaken of the geologic, production, and reservoir characteristics of the existing Mesaverde producing areas in the basin with those same characteristics at the Multiwell site near Rifle, Colorado. The geologic, production, and reservoir engineering parameters are being developed for the existing Mesaverde gas producing areas through analysis of log suites, pressure transient information, well completion information, and production histories, and through identification of natural fracture trends and an analysis of the present thermal regime.

A series of Mesaverde gas productivity maps are being developed for the Piceance Basin. These maps include gross interval and net sand thickness maps, a permeability-thickness (kh) map, thermal map (indicating areas of active gas generation), a natural fracture intensity map, and gas production (first year cumulative and ultimate recoverable gas) maps. The basin is subdivided into three areas having similar geologic and production characteristics. Stimulation techniques are reviewed for each area to determine the most effective stimulation technique currently used in the Mesaverde.

6. RESULTS/ACCOMPLISHMENTS:

STRATIGRAPHIC CORRELATION-DATABASE COMPILATION

More than 150 well-to-well correlations were made using the modified nomenclature of Lorenz (1983). The nomenclature for this report divides the Mesaverde Group into three genetically related intervals, i.e., Shoreline/Marine, Paludal, and Fluvial. Lorenz's (1983) terminology, germane to the Rulison Field area, was merged basin wide with the terminology of Johnson (1987) as the detailed stratigraphic analysis of the Multiwell site was extrapolated to the rest of the Piceance Basin. To accomplish this task and other map making tasks, a stratigraphic database was compiled. Well coordinates, subsea depth, thickness of each unit as well as other parameters essential to TITEGAS analysis were compiled.

THERMAL ANALYSIS

A thermal database for the Piceance Basin was compiled from available petrophysical logs. This database permits the determination of static bottomhole temperatures and geothermal gradients throughout the basin. Calculations of the geothermal gradients ($G^t$) permits the delineation of the 190°F isotherm to show potential gas maturation zones.

BHT CORRECTIONS

The Horner method of bottomhole temperature (BHT) correction requires a BHT from a maximum recording thermometer on each of several logging runs, estimates of circulation time prior to logging, and the time the logging instrument was last on bottom of the borehole (Fertl and Wickman, 1977). This data was located on only 43 wells in the Piceance Basin, and 34 static BHTs determined by Horner extrapolation appear valid and are plotted in Figure 1. These Horner corrected BHTs and two temperature surveys are the standards by which other methods of correction were derived or evaluated.

As a reliability check, an alternate method of BHT correction proposed by Middleton (1979) was employed on about one third (10) of the Horner corrected BHTs. This curve fitting technique permits BHT corrections on wells without knowledge of circulating time of drilling fluids. True formation temperature (BHT) can be found by this simple curve-matching technique if three or more time-sequential BHT measurements are available from the same well.

The method of BHT correction used in this study (on as many as 200 wells) was proposed by Chapman and others (1984) and is illustrated in Figure 1. This method of correcting BHT requires the time elapsed ($t_e$) since circulation ceased to be calibrated to a population of 34 Horner corrected BHTs. The formula for BHT correction resulting from curve fitting of the Piceance Basin Horner corrected population is of the form $T_c$ = BHT (1.108 - 0.02056 ln $t_e$). Geothermal gradients and depths to the 190° isotherm for this study were computed using BHTs corrected with this formula and those 34 Horner corrected BHTs. The maximum temperature correction is about 8 percent by this formula, which is considerably lower than the 20 percent or more proposed by the USGS (Johnson, 1987).

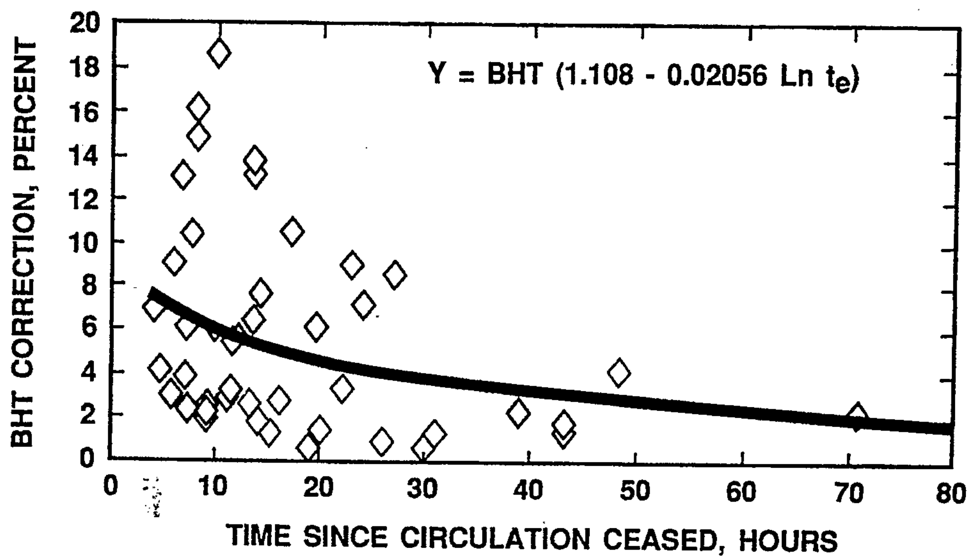


*Figure 1 Piceance Basin Horner Temperature Correction Plot and Curve Fit*

GEOTHERMAL GRADIENTS

Geothermal gradients ($G_t$) computed using the formula for the BHTs established above resulted in values less than those computed and mapped by the USGS (Johnson, 1987). The maps of this study do, however, exhibit essentially the same trends as those of the USGS, i.e., the highest geothermal gradients are in the southern Piceance Basin and the geothermal gradients decrease northward to the limits of the basin.

The southeast Piceance Basin, locus of Miocene through recent magmatism, is characterized by higher geothermal gradients. This results in a large area of active thermal gas generation from source rocks of the Paludal (coaly) interval and underlying Marine interval of the Iles Formation at relatively shallow depths, as shown in Figure 2. Northwest of the limit of magmatism, the basin is characterized by lower geothermal gradients. This results in the areas of potentially active gas generation from the paludal interval and the underlying Marine source rocks occurring at much greater depths along the basin axis. At the northern end of the basin, source rocks at temperatures of 190°F are 4,000 ft or deeper than corresponding source rocks at the southeast extremity of the basin.

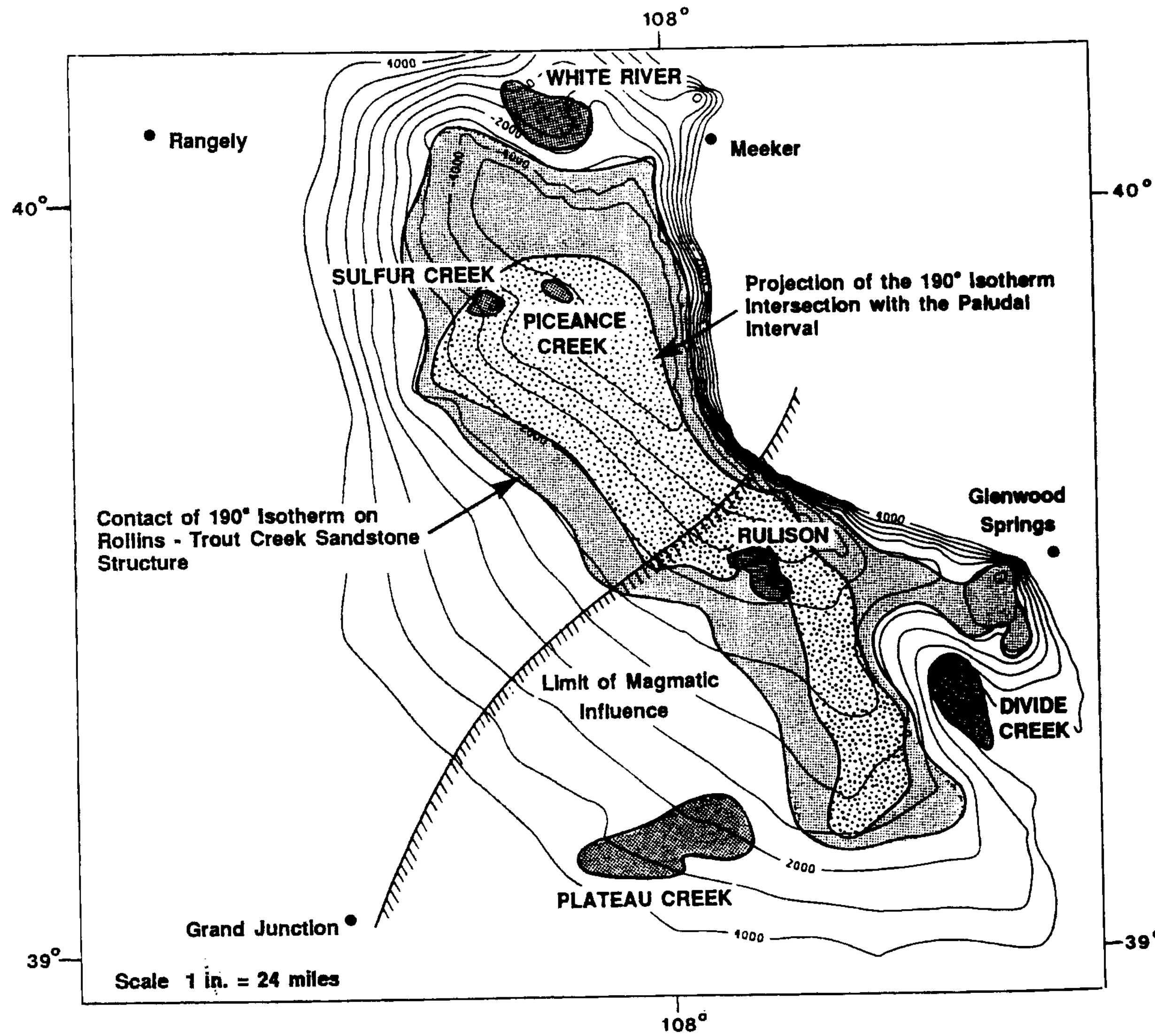


*Figure 2 Piceance Basin Geothermal Map*

## FRACTURE TRENDS

MWX-related studies indicate that a west-northwest-trending unidirectional, sub-parallel, regional fracture permeability system occurs throughout the Mesaverde Group rock for all depositional intervals. Orientation information from published outcrop studies and from two wells was synthesized basin wide to characterize the extent of that system for this project. Fracture trends (joints and coal cleats) within the Mesaverde Group essentially belong to two regional fracture systems, an older Hogback system and the younger Piceance system (Verbeek and Grout, 1984a).

Fractures in outcrop are usually reported in near orthogonal sets of a dominant, usually older fracture and a subordinate, usually younger fracture. Work by Sandia National Laboratories strongly suggests that regional fractures in the subsurface, in relatively undeformed areas, should be predominately unidirectional with few, low angle intersections. Local flexure could produce other fracture sets that are superimposed on the regional sets (Lorenz and Finley, 1989).

On the northeastern flanks and in the center of the basin, the Mesaverde fractures are of the predominately northwest-trending Hogback system. These fractures trend parallel to the basin synclinal axis and might be genetically related to uplift of deeper parts of the axial area. Figure 3 is a structure map of the basin outlining the general domain of the Hogback system fractures. The Rulison area lies within the Hogback fracture domain.

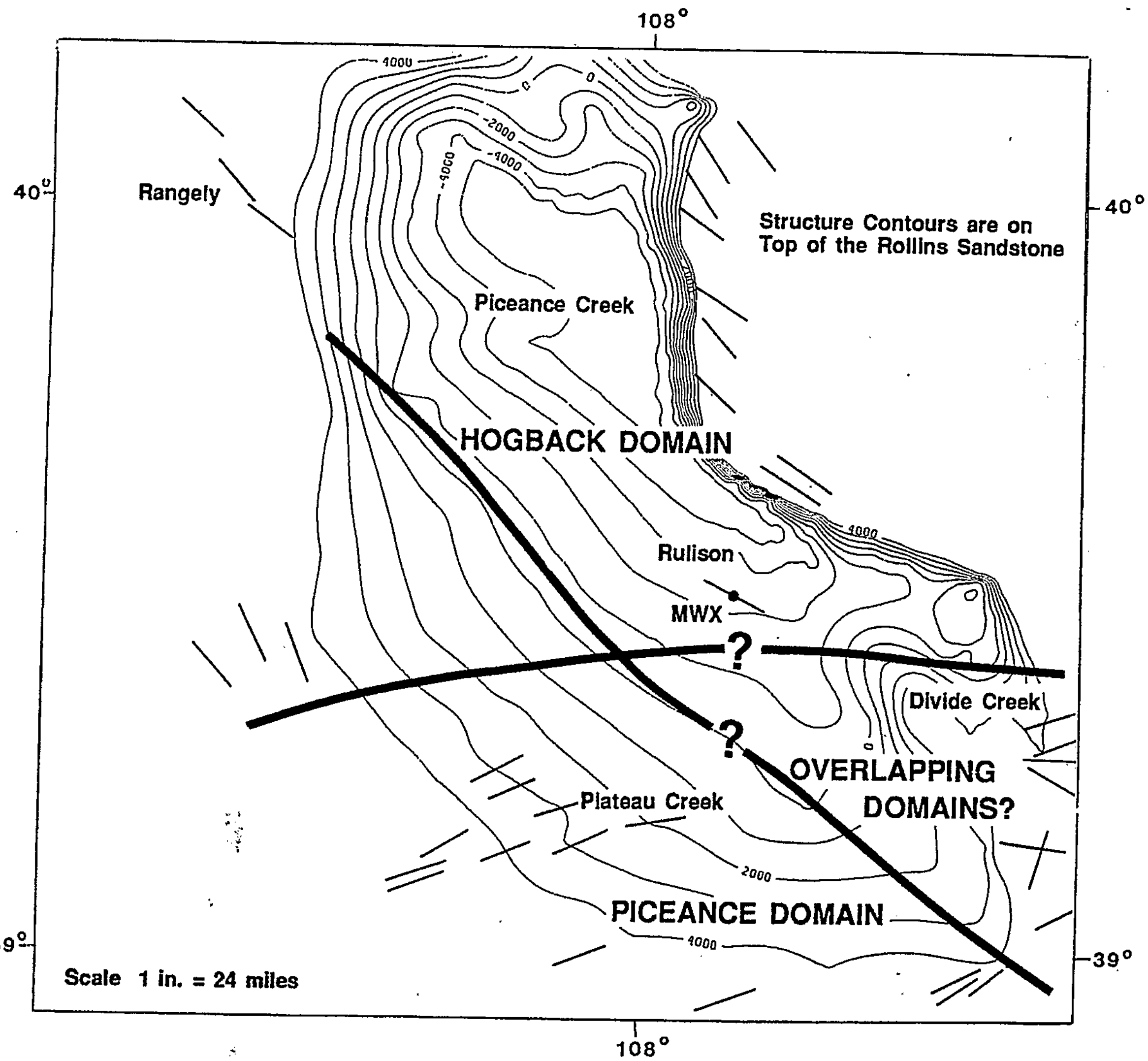


*Figure 3 Mesaverde Regional Fracture Orientations*

The Mesaverde in the southern part of the southwestern flank of the Piceance Basin contains a predominately unidirectional fracture set trending east-northeast (Lorenz and Smock, 1985). This set is interpreted by Verbeek and Grout (1984) to be younger than the Hogback system and part of their Piceance system which occurs predominately in the Wasatch Formation. In this domain of Piceance system fractures, coal face cleats also trend east-northeast parallel to the regional fractures. The Plateau Creek Field area lies within the Piceance fracture domain.

The southeastern Piceance Basin is the subject of little published fracture information. It contains areas of high flexure, such as the northwest-trending Divide Creek anticline, as well as bifurcations of the present basin synclinal axis. These structural trends suggest the northwest-trending dominant fractures should be present. In coal outcrops, east-northeast-trending face cleats have been mapped along the eastern margin of the basin. This suggests that the Piceance system is also present in the southeastern margin of the basin on trend with those to the west across the basin (Decker and Seccombe, 1986). The southeastern area is delineated as an area which probably contains overlapping domains with the possibility of both the Hogback and Piceance fractures being present.

An earlier study of Mesaverde fracture orientations in the Rangely and Douglas Creek arch area (Knutson, 1977) recognized several joint sets with a dominant "master joint" set trending generally northwest. Those fractures could not be correlated directly with any of those mapped by Verbeek and Grout (1984a) because their relative ages are not known. They may be related to the Hogback system, younger Piceance system, or a separate system more related to the Uinta basin.

MWX reservoir tests strongly suggest that not only fractures but cross fractures are a necessity to enhance production (Lorenz and others, 1986). It may then be inferred that the best producing wells in the Piceance Basin are in areas where the dominant fracture set (usually the older) is cross cut by other fractures. Cross cutting fractures would be possible in overlapping regional fracture domains or in areas affected by local anticlinal flexure. The trend of cross-cutting, but subordinate, fractures has been related to local anticlinal bending by Lorenz and Smock (1985).

## PRODUCTION AND STIMULATION ANALYSIS

Production histories were examined for 243 active Mesaverde gas wells in the Piceance Basin to determine the Mesaverde producing interval, well completion intervals, stimulation type, and ultimate gas recovery.

Table 1 indicates that of the 243 Mesaverde gas wells, 34 are Fluvial interval completions, 40 are Paludal completions, and 169 are Marine (Corcoran, Cozzette, and/or Rollins) completions. The average ultimate gas recovery per well for each of the three intervals is respectively 399 MMCF (Fluvial), 496 MMCF (Paludal), and 454 MMCF (Marine).

Table 2 presents the stimulation statistics for the 243 Mesaverde gas wells. Five stimulation fluid categories were selected: (1) AGW, carbon dioxide or nitrogen-assisted gelled or crosslinked gelled water carrying proppant; (2) N2F, nitrogen-based foams carrying proppant; (3) NON, no stimulation; (4) Other, small sand-oil or sand-condensate stimulations performed prior to 1975; and (5) UGW, unassisted gelled or crosslinked gelled water carrying proppant.

The unstimulated wells had the highest average ultimate gas recovery, 1,622 MMCF/well from 29 wells. This high average ultimate gas recovery reflects encountering open natural fractures during drilling, primarily at the Divide Creek and Rulison Fields.

*Table 1 Piceance Basin Mesaverde Group Completion Statistics*

| Formation | No. of Wells | Average UGR, MMCF | % Wells to Achieve UGR |
|---|---|---|---|
| Fluvial | 34 | 399 | 29 |
| Paludal | 40 | 496 | 27 |
| Marine | 169 | 454 | 17 |
| **TOTAL** | **243** | **453** | |

*Table 2 Piceance Basin Mesaverde Group Stimulation Statistics*

| Stimulation Type | No. of Wells | Average UGR, MMCF | % Wells to Achieve UGR |
|---|---|---|---|
| AGW | 77 | 326 | 27% |
| N2F | 38 | 158 | 29% |
| NON | 29 | 1,622 | 17% |
| Other | 16 | 574 | 25% |
| UGW | 83 | 276 | 37% |

The "Other" category has the second highest ultimate gas recovery of 574 MMCF/well from 16 wells. This is misleading because it includes the results of small sand-oil stimulations and/or small breakdown acid jobs in early wells drilled in the Divide Creek Field and Rulison Field, areas having known, open natural fractures.

Assisted gelled water stimulations averaged 326 MMCF/well ultimate gas recovery from 77 wells. Unassisted gelled water averaged 276 MMCF/well ultimate gas recovery from 83 wells. These statistics reflect the assistance given to treating liquids recovery, following hydraulic fracture stimulation, by an entrained or dissolved gas phase in the stimulation fluid.

The nitrogen-based foam stimulations averaged 158 MMCF/well ultimate gas recovery from 38 wells. This is the lowest per well recovery of any of the stimulation techniques evaluated in active Piceance Basin Mesaverde gas wells. Thirty-five of the nitrogen-based foam stimulations have been applied to wells in one concentrated area in the Marine interval in the Plateau Creek Field. These results, therefore, should not be construed as being representative basin wide for nitrogen-based foam stimulations in the Mesaverde.

As a result of evaluating all available geologic and production information, the Piceance Basin was subdivided into three discrete Mesaverde gas producing areas having similar geologic and production characteristics: (1) Divide Creek, (2) Rulison-Grand Valley, and (3) Plateau Creek. Table 3 presents the average ultimate gas recovery per well for the three partitioned areas.

*Table 3 Piceance Basin Mesaverde Group Partitioned Areas Statistics*

| Area | No. of Wells | Average UGR, MMCF | % Wells to Achieve UGR |
|---|---|---|---|
| Divide Creek | 22 | 1,517 | 18 |
| Rulison - Grand Valley | 41 | 605 | 41 |
| Plateau Creek | 142 | 232 | 28 |

The Divide Creek Area, T7-8S R90-91W and T10S R90W, produces primarily from the Marine interval of the Mesaverde. This area has the highest average gas recovery per well, 1,517 MMCF/well from 22 wells, and is an area known to have open natural fractures observed in core.

The Rulison-Grand Valley area, T6-7S R94-96W, produces primarily from the Paludal and Fluvial intervals of the Mesaverde. This area has an average gas recovery of 605 MMCF/well from 41 wells. Natural fractures have been observed in Marine, Paludal, and Fluvial core, both at the Multiwell Experiment and in core taken by Barrett Energy in the Marine interval in conjunction with the Gas Research Institute.

The Plateau Creek area, T10S R94-96W, produces primarily from the Marine interval of the Mesaverde. This area has an average gas recovery of 232 MMCF/well from 142 wells. Two areas, one in T10S R94W and the other in T10S R96W, have average per well gas recoveries greater than 1,000 MMCF/well. Production in these two areas is believed to be influenced by the presence of natural fractures. Of the 142 wells considered in the Plateau Creek area, 6 will recover in excess of 1,000 MMCF/well, and 16 wells will recover in excess of 500 MMCF/well.

It is inferred from this analysis that those better producing wells within each partitioned area are the result of penetrating an interconnected, three-dimensional fracture network. The network would consist of the regional fracture system connected by cross fractures, probably produced by local structural flexures.

7. FUTURE WORK:

Future work will include construction of gross and net sand thickness maps for the Marine, Paludal, and Fluvial Mesaverde of the Piceance Basin, as well as the kh map using the results of TITEGAS log analysis. Two approximately perpendicular basin wide cross sections will be prepared showing the gross thickness of the Marine, Paludal, and Fluvial intervals. Following completion of the detailed log analysis, the position of water zones, transition zones, and gas zones for each unit will be superimposed on these cross sections. Additional cross sections of each partitioned area will be constructed to demonstrate the productive units.

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# RE-ANALYSIS OF MWX PALUDAL ZONE STIMULATION DATA

1. CONTRACT NUMBER: DE-AC21-87MC24264

   CONTRACTOR: NSI Technologies, Inc.
   (Fmr Nolte-Smith, Inc.)
   7030 S. Yale, Suite 502
   Tulsa, Oklahoma 74136
   (918) 496-2071

   PROGRAM MANAGER (CONTRACTOR): Dr. Michael B. Smith

   PRINCIPAL INVESTIGATORS: William K. Miller II
   Dr. Michael B. Smith

   METC PROJECT MANAGER: Karl-Heinz Frohne

   PERIOD OF PERFORMANCE: Oct., 1987 to Oct., 1989

2. SCHEDULE/MILESTONES:

```
                               1989 Program Schedule
                                   O N D J F M A M J J A S O
Accumulation of Data               ---
Coastal Data Anal.                     ------
Fluvial Data Anal.                              -----
Compare Zonal Results                                -----
Reporting                                    ---          ---
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3. OBJECTIVE:

The objective of this contract is to provide a comprehensive independent review/analysis of the fracture stimulation data obtained during the DOE Multiwell Experiment (MWX) and provide new insight into the data interpretation and factors affecting fracture behavior in tight gas sands, and in particular, lenticular reservoirs.

4. BACKGROUND STATEMENT:

For a number of years DOE has been engaged in research to enhance gas recovery from "tight gas sands", particularly the lenticular sandstone formations common to the Western United States. The purpose of this research is to establish production potential from lenticular reservoirs, improve existing production technology; and ultimately, to demonstrate the economic feasibility of drilling and completing wells in this unconventional gas source. To investigate these tight gas sands, DOE established the multiwell facility (MWX) near Rifle, Colorado to conduct in-depth geologic and engineering research into the character of gas production from these formations. The facility consists of three closely spaced wells (MWX-1, MWX-2, and MWX-3) drilled through the lenticular Mesaverde formation in the Piceance basin. Testing has included extensive coring, production testing, and instrumented fracture stimulation experiments. Because one of the more important aspects of the MWX project was to establish the predictability of well stimulation procedures, extensive pre-frac and during-frac testing was conducted in the Paludal, Coastal, and Fluvial zones; this being the source of data under re-evaluation. The content of this particular paper deals only with the Paludal zone.

## 5. PROJECT DESCRIPTION:

The primary goal of the Paludal data review was to establish conditions affecting fracture geometry and behavior in this lenticular environment; and determine the degree of predictability of fracture behavior from pre-frac testing. Since variations of in situ stress are the primary control mechanism over fracture geometry, a major effort was made by DOE to collect stress data in the Paludal and its bounding layers. Much of this data was re-analyzed to confirm prior results showing significant stress differences in the lenticular formations, to evaluate the micro-frac testing procedure, and to examine correlations between measured stress and other formation properties. Formation properties correlations were found to exist for deriving a stress profile, which was used in a pseudo 3-D fracture simulator to history match the net treating pressures from the minifracs and main fracture treatment. This review resulted in some significant differences from previous analyses, including unique differences in the stress profile, lower leak-off coefficients, and the history match of the net treating pressures being relatively straight forward, i.e. a fairly direct explanation for the unexpected high treating pressures observed. The following discusses the Paludal stimulation review.

### REVIEW OF STRESS DATA

Most of the Paludal stress tests were performed using the micro-frac procedure, which typically consists of pumping a small volume of low viscosity fluid into a 1-2 foot interval at 5-20 GPM and measuring the instantaneous shut-in pressure (Kehle 1964; McLennan 1982; Warpinski 1983). Because of the small volume injected and the small, narrow fracture created, theoretically the fracture should close quickly after shut-in and the closure stress approximated by the ISIP.

The Paludal micro-frac tests were re-analyzed using a plot of pressure versus the square-root of shut-in time to determine closure pressure (Nolte 1979). This method relies on linear flow behavior and is sometimes referred to as the "reservoir type" method. These results were compared to those obtained from the ISIP analysis (Warpinski 1987) and while both methods showed good agreement, it was concluded that the "reservoir type" analysis yielded clearer, more definitive results than the subjective pick of an ISIP. Larger volume stress tests were also performed in the main Paludal sands, including a step-rate test/flowback and pump-in/flowback test. The re-analysis of these tests also showed good agreement with previous analyses (Warpinski 1984), using similar methods to evaluate the data.

Figure 1 shows a comparison of the re-calculated frac gradients and those determined from previous analyses of the stress tests. This good agreement (coefficient of linearity R = 0.961) implies that the ISIP analysis of

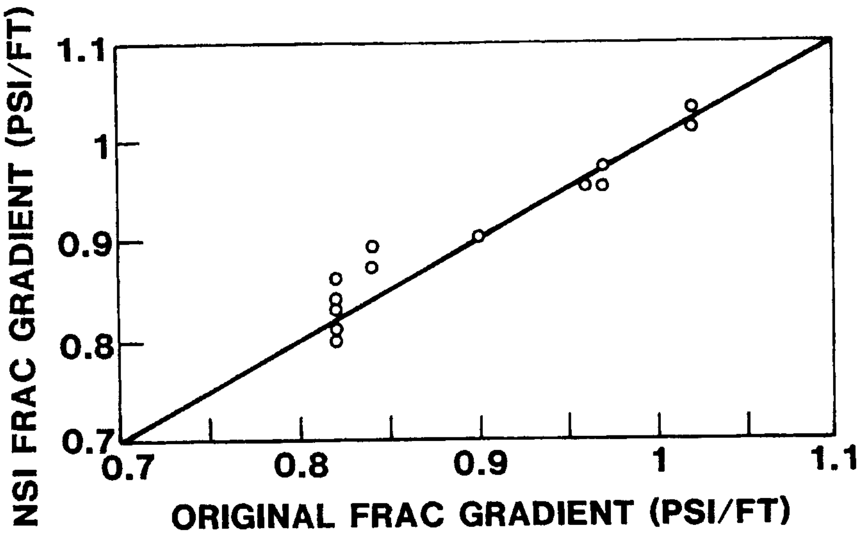


FIGURE 1. Paludal Stress Results.

micro-frac tests does yield consistent, repeatable results if proper care is taken with the testing and analysis. However, the "reservoir type" method can, in many instances, provide more definitive and objective results.

A point clearly indicated by Figure 1 is that significant stress differences (on the order of 0.2 psi/ft or 1500 psi) can exist in this layered, heterogeneous formation. This somewhat unexpected phenomenon has been extensively commented on in previous MWX publications (Warpinski 1987) and is verified here. Also, considering the good agreement between the two analyses and the complexity of the Paludal zone, it seemed certain that similar agreement would prevail for stress tests in the lower Marine, and uphole Coastal and Fluvial zones. Therefore, the previous analyses for these zones was used with the Paludal results to look for correlations between in situ stress and other formation properties.

## STRESS CORRELATION ANALYSIS

Correlations between measured stress and other rock properties, such as lithology and acoustic velocity, considered stress results from 38 tests from the four Mesaverde zones including the Fluvial, Coastal, Paludal, and Marine. K factor, derived from the measured closure stress using the equation below (Breckels 1981), was used instead of closure stress to normalize out the effects of depth and pore pressure.

$$K = (\sigma_c - P_{res}) \;/\; (OB - P_{res}) \qquad (1)$$

Using the gamma-ray (GR) measurements to define lithology (using a mean GR from an 11 foot interval centered around each test zone), there appeared to be a general relation, as seen in Figure 2; however, significant scatter existed. This scatter was thought to be a function of the Paludal zone being very heterogeneous and layered with coal streaks; this heterogeneity manifesting itself in the presence of thin lithology streaks, with rapid changes from sand to shale to sand, etc. In the analysis, data from a

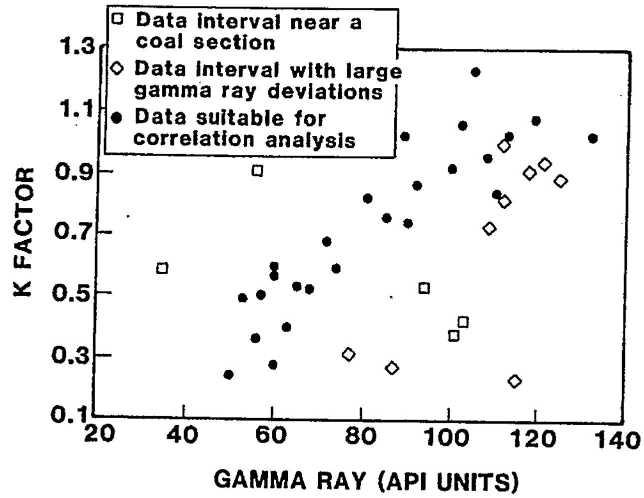


FIGURE 2. K-Factor Versus Gamma-Ray.

stress test was deemed unsuitable for correlation analysis if it was in or near a coal section, or if the mean GR value had a large standard deviation, e.g. complex layered lithology. As shown in Figure 2, when data obtained near coal sections or with high GR deviations were separated out, the remaining data showed a strong trend of increasing stress (as characterized by "K") with increasing GR.

Figure 3 shows the "filtered" K factor data plotted. It was hypothesized that the correlation between K factor and GR may be bilinear. For GR

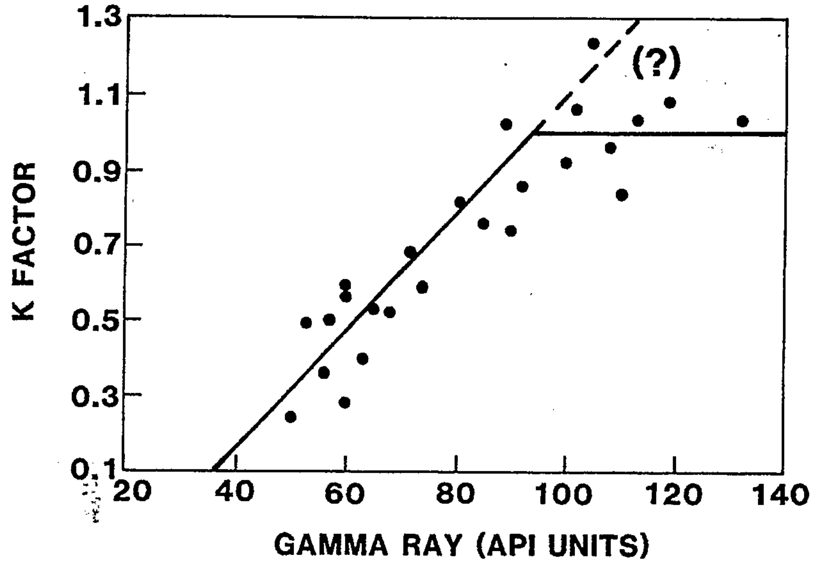


FIGURE 3. "Filtered" K-Factor Versus Gamma-Ray.

values greater than 90 API Units, the data seemed to flatten out at a K = 1.0, implying that closure pressure is equal to the overburden pressure. If the behavior in Figure 3 is assumed to be true, then the relationship between GR values less than 90 and K is given as

$$K = MGR * 0.01532 - 0.458 \tag{2}$$

and above a GR of 90, the relationship can be defined simply as K = 1. If, in fact, the correlation is not bilinear, but linear as shown by the dashed line; then the entire relationship would be defined with Equation 2.

To investigate a relationship between sonic data and in situ stress, the sonic log from MWX-2 was used to calculate K factor from the Poisson's Ratio. Figure 4 shows a comparison of the sonic calculated "K factors" versus the stress calculated "K factors" for the Fluvial and Marine zones, the data having a coefficient of linearity of R = 0.88. The data

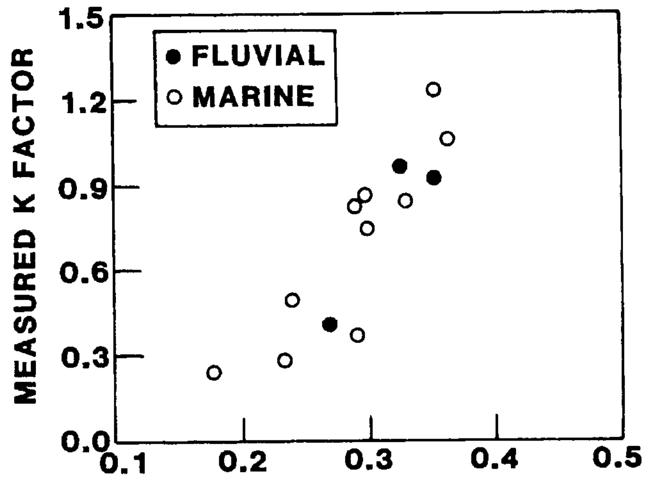


FIGURE 4. Measured K-Factor Versus Sonic Log K-Factor.

from the Paludal zone showed poor linearity. While it is evident that a relation exists between sonic derived and measured K, it is NOT 1:1, and Equation 1 can not be used to calculate closure stress. The following table shows the comparison between the correlations derived from the sonic and GR logs, with the GR correlations showing the best accuracy.

| Correlation | Paludal Zone Data | R | Avg. Error (psi) |
|---|---|---|---|
| Sonic | Included | 0.69 | 360 |
| Sonic | Not Included | 0.88 | 257 |
| GR | Included | 0.93 | 200 |
| GR | Not Included | 0.94 | 206 |

STRESS PROFILE

After generating stress profiles for the Paludal frac zone in MWX-1 using both the linear and bilinear GR correlations, the linear correlation (with only a few minor adjustments) was found to more closely approximate the net treating pressures and created heights recorded during the fracturing experiments. Figure 5 shows the smoothed stress profile used to history match the minifracs and main treatment.

In addition to the micro-frac stress tests used to generate the Paludal stress profile, larger volume stress tests were conducted in the Paludal sands 3 and 4 as mentioned earlier. Since this data was not included in deriving the lithology correlation or the stress profile, it was useful to

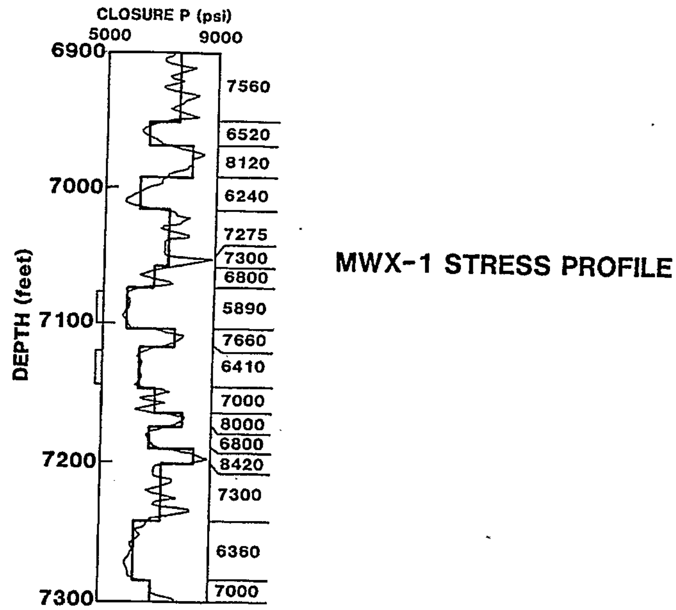


FIGURE 5. MWX-1 "Smoothed" Stress Profile.

compare these results to the profile. In the MWX-1 frac zone, the first flowback test yielded a closure stress of 5800-5900 psi (Warpinski 1984), as compared to the profile stress through the upper sand of 5890 psi. The breakdown test in the same zone in MWX-3 gave a closure stress of 5800 psi (Warpinski 1984). This good agreement between the large volume tests and the generated profile gave confidence in the profiles' use for history matching the fracturing pressures.

## MINIFRAC ANALYSIS

The first minifrac performed in the Paludal zone in MWX-1 consisted of pumping 15,000 gals. of non-crosslinked 30 lbs./1000 gals. gel, at an average injection rate of 10 BPM. Both Sands 3 and 4 were open during this and the subsequent fracture injections. From the post-minifrac pressure decline, a closure pressure of 6411 psi was measured at a shut-in time of 20.3 minutes. This corresponds to the average stress in the lower Paludal sand as seen in Figure 5. If only the lower sand were closed at this point then several questions had to be answered as to the validity of the pressure decline analysis used to calculate the leak-off coefficient. With the higher stress zone closing first, would the fluid from this zone be squeezed into the lower stress zone and would this be considered the same as continued injection into this zone? And, of even greater importance - What would be the correct gross and leak-off heights to use in the calculation of leak-off coefficient? In dealing with these problems, it became apparent that the pressure decline analysis (type curve analysis) was not without weakness in determining a leak-off coefficient for complex stress conditions such as the Paludal and its surrounding layers. When all the possible combinations of injection time, gross height, and leak-off height were analyzed, the results varied from C = 0.00009 ft/min**0.5 to C = 0.003 ft/min**0.5, an intolerable range.

It was found, though, that the pressure decline analysis, when coupled with history matching of the actual injection and decline pressures, was still a powerful tool. In the history match, a wide range of leak-off values can be used to get an injection pressure history match simply with minor variations in fluid viscosity and modulus. But, the fluid efficiency and pressure decline must be consistent with the leak-off coefficient used. Honoring these stipulations, the history match of the first Paludal minifrac was achieved with a leak-off coefficient of 0.0001 ft/min**0.5 as seen in Figure 6. The stress profile in Figure 5 was used in the model to simulate height growth, the results of which are compared to the post-minifrac temperature log in Figure 7 (Warpinski 1984). While not an exact match, the temperature log was run 22 hours after injection and only had a 10 degree variance over the fractured interval, leaving some room for interpretation.

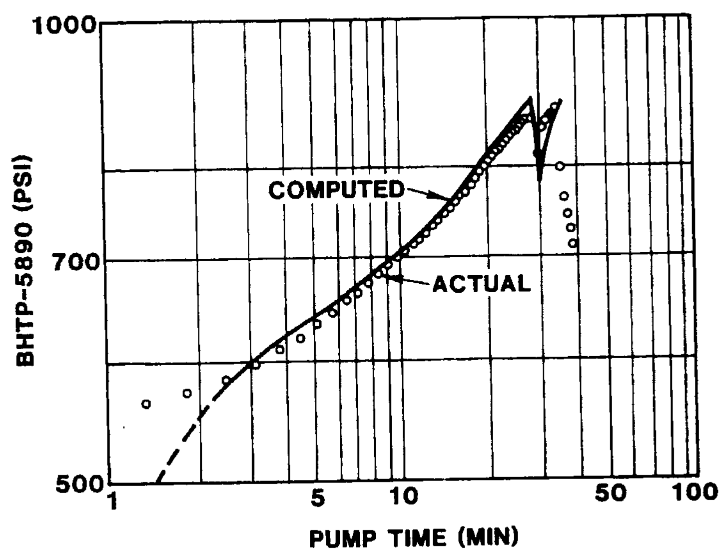


FIGURE 6. Pressure History Match of Paludal Minifrac #1.

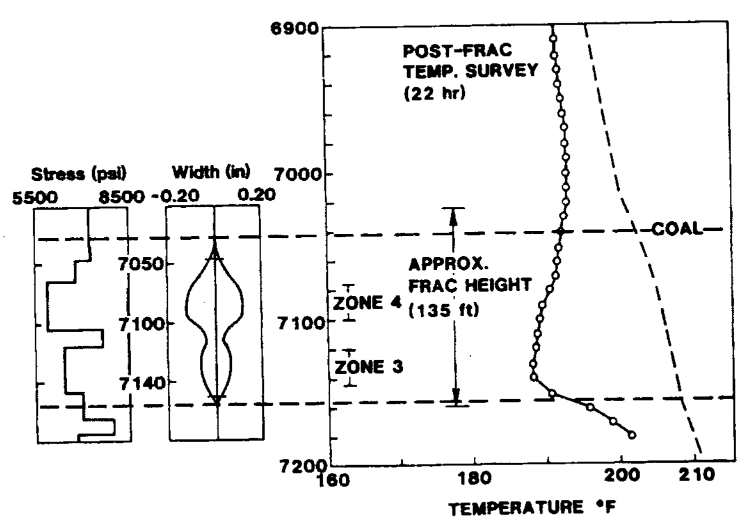


FIGURE 7. Measured Versus Simulated Height, Minifrac #1.

To obtain the minifrac pressure history match required that the computed fluid efficiency match that determined from the pressure decline analysis, both from pressures and time-to-close. This stipulation was met, the computed efficiency being 0.63 and the efficiency from the pressure decline analysis being 0.66. To look at the actual versus computed pressure decline, leak-off coefficients ranging from 0.0001 to 0.001 ft/min**0.5 were evaluated as seen in Figure 8. This indicated that the early time actual data, i.e. less than 20 minutes or the early closure time (lower zone), seemed to decline faster than predicted for the 0.0001 - 0.0003 coefficients. Beyond this point, though, the actual decline seemed to parallel the 0.0001 ft/min**0.5 curve. Two possible causes for the

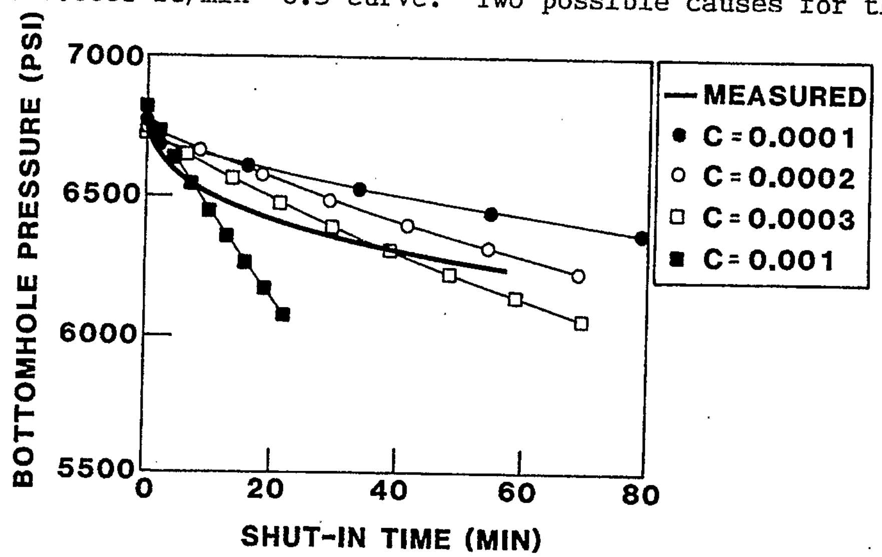


FIGURE 8. Minifrac #1 Pressure Decline Match.

apparent high leak-off in the early time were speculated to be 1) higher leak-off in the lower Paludal sand and/or 2) crossflow from the higher stress sand to the lower stress sand. From the pressure decline analysis there did not appear to be any significant leak-off to a secondary source such as natural fissures (Nolte,1979). Thus, the 0.0001 ft/min**0.5 leak-off coefficient was thought to be consistent with the pressure decline analysis, pressure history match, and core analysis which did not report any fissures and calculated permeabilities in the 1-3 microdarcy range.

While a second minifrac was also conducted in Paludal sands 3 and 4 in MWX-1, the analysis followed the same methods and is not discussed in detail here. This test consisted of pumping 30,000 gals of 60 lbs/1000 gals gel, a more viscous fluid than used on the first minifrac. The injection rate was the same at 10 BPM. Once again, a leak-off coefficient of 0.0001 ft/min**0.5 was required to obtain a history match of the pressures and to match the post-minifrac temperature log. The actual pressure decline was also characteristic of the computed pressure decline for this leak-off coefficient.

FRACTURE TREATMENT ANALYSIS

The Paludal fracture treatment consisted of pumping 81,500 gals. of fluid (65,000 gals. gel) and 193,000 lbs of 20/40 mesh sand at an average injection rate of 20 BPM. The treatment was pumped down the annulus and an HP pressure gauge hung in the tubing to monitor BHTP. Using the stress profile in Figure 5 and a leak-off coefficient of 0.0001 ft/min**0.5, the pressure history match in Figure 9 was obtained. The three shut-downs during the pad were intentional to perform an alternative leak-off analysis. As shown by the figure, a reasonable match was obtained up to about 50 minutes, at which time the net BHTP started increasing at an abnormal rate indicating that fracture extension had stopped. Attempts to history match this behavior were unsuccessful. The crosslinked gel should have resulted in even lower leak-off than the uncrosslinked gels used on the minifracs, making the probability of an early screen-out due to excessive leak-off unlikely. Thus, attention was turned to looking at other possible causes.

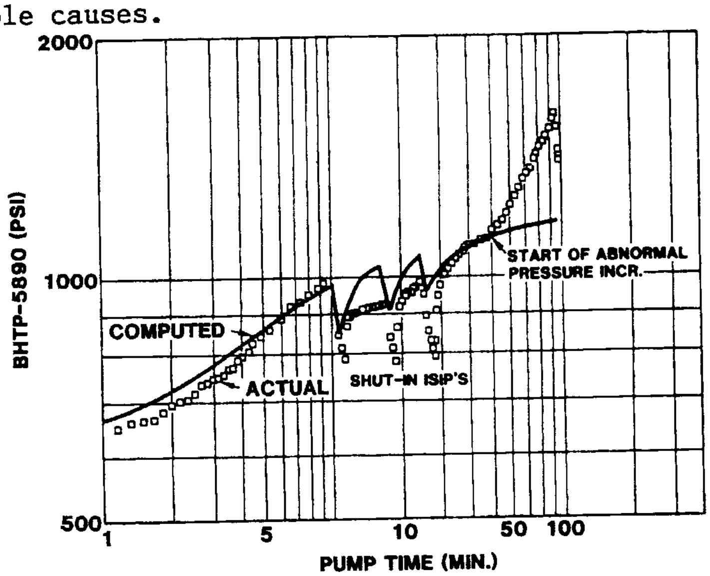


FIGURE 9. Pressure History Match of Paludal Fracturing Treatment.

To look at why the abnormally increasing pressures were not observed during the minifrac, the pressures from the three injections were compared on a volume basis. As seen in Figure 10, all three injections tracked very close, with the BHTP increasing with each subsequent injection as would be expected due to increasing fluid viscosity. The figure shows that the amount of fluid pumped on the minifracs was insufficient to reach the point at which the pressure started increasing on the main treatment. Looking at how far proppant had traveled after 50 minutes injection on the main treatment, the simulator predicted a propped length of about 300 feet. Comparing this to the estimated sand geometry in Figure 11, it was postulated that the proppant reached the outer boundaries of the sand splay and/or channel and the stress of the shalier rock beyond this point was high enough to restrict fracture width and cause proppant bridging. With the two sands and different geologies, many possibilities could have caused the abnormal pressures including only one wing of the fracture in only one sand screening-out. The post-frac pressure decline could not be analyzed to calculate a leak-off coefficient because of the abnormally high pressures at the end of the treatment and the likelihood of insufficient breaker added to the gel. Also, due to sand fill in the wellbore, only the top of the fracture was seen with the post-frac temperature log. The

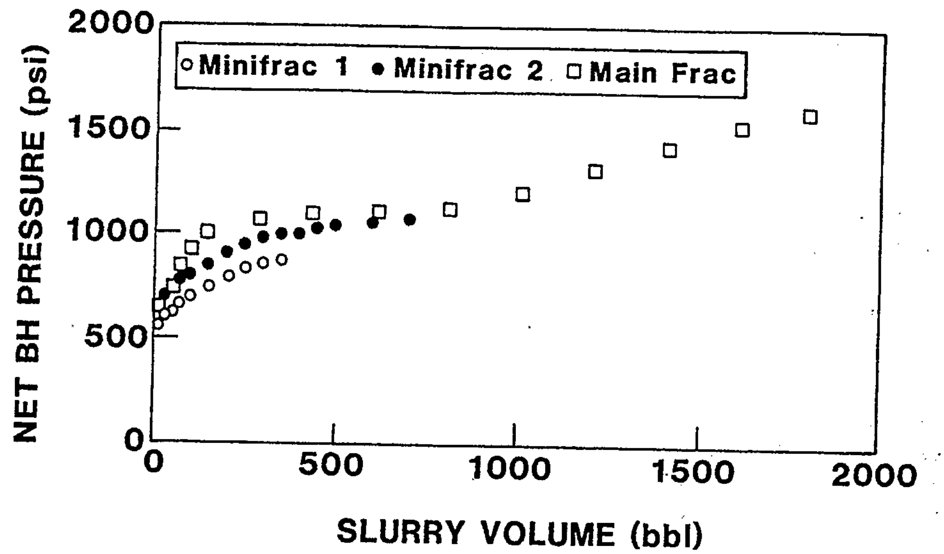


FIGURE 10. Comparison of Minifrac and Main Treatment Net Pressures.

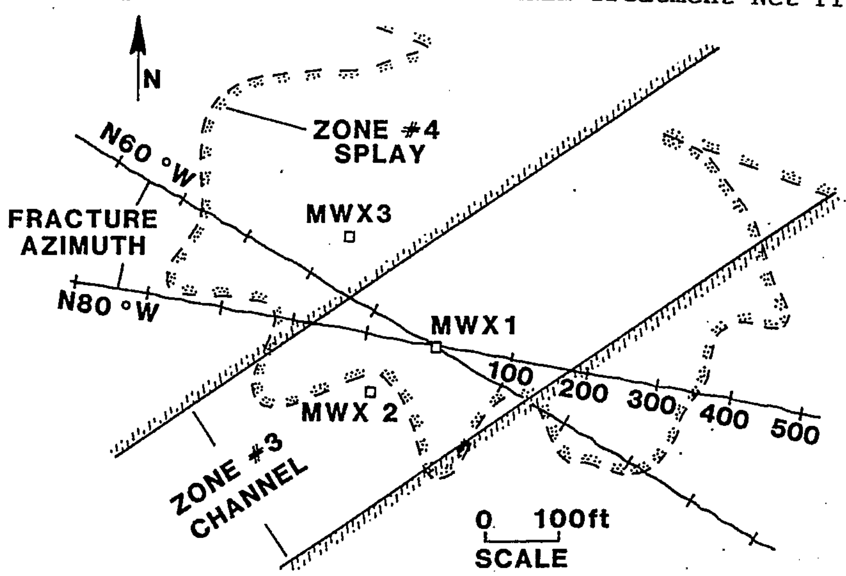


FIGURE 11. Estimated Paludal Sand Geometry.

simulated height of about 190 feet was, though, consistent with the limited borehole seismic signals obtained, which all fell within a 200 ft height window (Warpinski 1985).

6. RESULTS:

- Compares ISIP method to "reservoir type" method for analyzing stress tests, the latter providing more definitive and objective results.
- Defines a relationship between in situ stress and lithology for the Mesaverde Formation.
- Shows the minifrac pressure decline analysis, by itself, to have weakness in a complex environment such as the Paludal zone; but, when coupled with pressure history matching to still be a powerful tool.

- A straight forward explanation based on vertical and lateral variations of in situ stress is provided for the previously noted high fracture treating pressures in the Paludal zone.
- Simulated fracture geometry is consistent with the estimated sand geometry for the Paludal, providing one of the few documented cases of BHTP behavior when proppant reaches a lens boundary(s).

## 7. FUTURE WORK:

Review of the Coastal zone data is near completion, which will be followed by a similar review for the Fluvial data. At the conclusions of the review of all three zones, a comparative analysis will be performed to establish patterns of similarity/difference in fracture behavior; and set forth guidelines for future fracture testing and design in the Mesaverde lenticular sandstones.

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RESERVOIR ANALYSIS OF BLANKET SANDS USING A NUMERICAL MULTI-MECHANISTIC MODEL

1. **CONTRACT NUMBER:** DE-AC21-87MC24157

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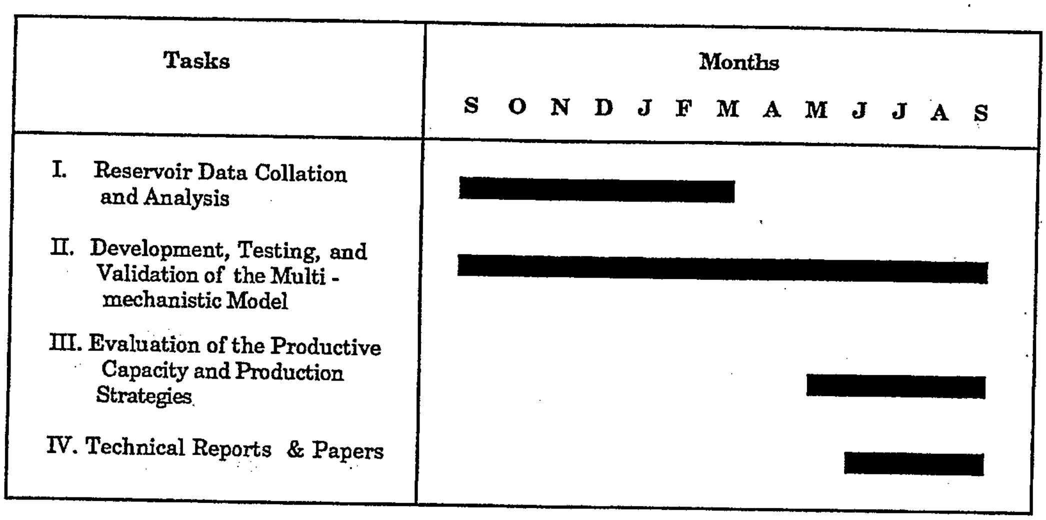
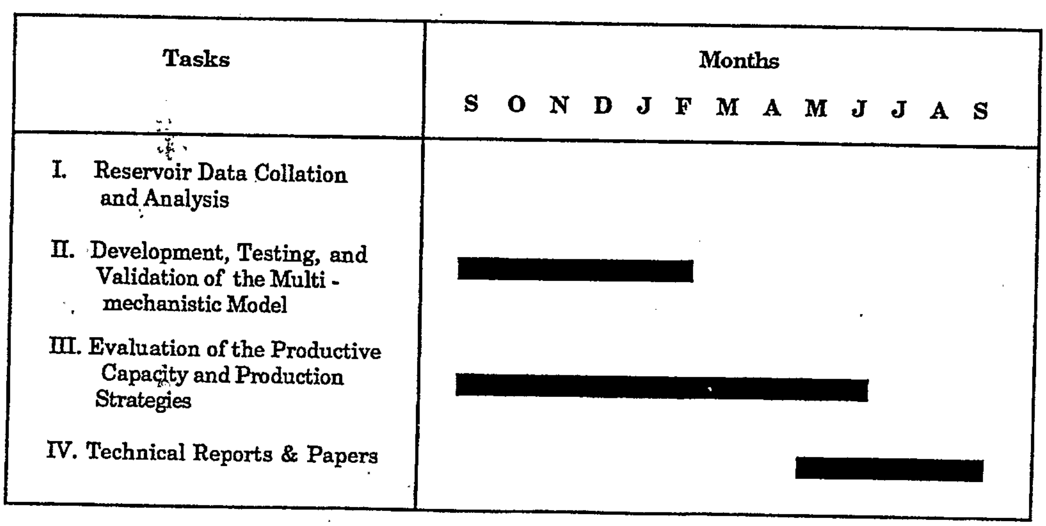
CONTRACT PERIOD OF PERFORMANCE: September 30, 1987-September 29, 1989

2. **SCHEDULE/MILESTONES:** **1987/1988 PROGRAM SCHEDULE**




**1988/1989 PROGRAM SCHEDULE**



## 3. OBJECTIVES:

The primary objective of this research is to conduct a comprehensive analysis of the flow of gas in the tight blanket sands of the Mesaverde formation with the intent of fostering a better understanding of the physics governing such flow. Such understanding is aimed at providing the basic premise for the development of appropriate predictive model which is to be subsequently used for establishing optimal production schemes for the tight blanket sands of the Mesaverde formation. In order to achieve the stated objective, the project is made up of three main tasks, namely:

- Reservoir data collation and analysis for the blanket sands;
- Development, testing and validation of the multi-mechanistic reservoir model proposed to be used in this study; and
- The utilization of the model to evaluate production schemes and the evolution of an optimized scheme for the blanket sands.

The target of this endeavor is to enhance the knowledge base necessary for the development of the appropriate technology for safe and economic exploitation of natural gas from the tight blanket sands of the Upper Cozzette sand.

## 4. BACKGROUND:

The importance of the role that natural gas from tight formations would play in the totality of the energy picture for the United States can not be overemphasized. This is true both from the perspectives of immediate energy-sufficiency as well as future energy security, both of which deserve strategic considerations.

The Western United States has an abundance of natural gas reserves in tight (low-permeability) formations. The current estimate of these reserves is approximately 5,703 trillion cubic feet, and a detailed resource study for the Piceance basin estimates 420 trillion cubic feet for that basin alone, thereby making tight gas a possible major contributor to the country's future energy needs. The development of this resource, however, has been limited, primarily because of an inadequate understanding of the fluid flow dynamics associated with tight formations. Without this understanding, future attempts at developing practical and economical exploitation technology will continue to yield inadequate levels of success. The other major source of the problem is the lack of laboratory and field data used as input into such models. Major effort by the U.S. Department of Energy to procure such data over the past several years should help to alleviate the problem in this regard. However, analysis and utilization of these data for correct interpretation presents the most challenge today. This is the main target of this work.

## 5. PROJECT DESCRIPTION:

### THE METHOD OF APPROACH

### The Multi-Mechanistic Model

The basis for the mathematical formulation of this problem using the multi-mechanistic approach is defined by two potential fields, namely a pressure gradient field and a concentration gradient field. The basic premise is that the pore space in tight formations is comprised of a network of micropores and macropores. The micropores are believed to be of molecular dimensions in diameter, whereas the macropores are much larger. It is further hypothesized that the micropores are accessible only to gas, whereas the water primarily resides in the macropores. When a pressure gradient is imposed upon this system due to the presence of a production well, then water would flow through the macropores (i.e., the natural fracture network) into the well. This process disturbs the previously existing hydrodynamic equilibrium between the gas dissolved in the water and the gas in the micropores creating localized concentration gradients. As a result of these localized concentration gradients, gas is driven into the macropores by Fickian diffusion. Hence, in time substantial quantities of both water and gas are produced at the well. This step-wise superposition of two flow fields upon one another generates an overall production mechanism which is referred to as multi-mechanistic flow regime. The details of this model and its applications have been well documented in earlier works by Sung and Ertekin (1986). The equations governing the unsteady state flow of water and gas are presented below.

$$\nabla\left[D_g\left(\frac{S_g p_g}{z}\right)+5.615\frac{\lambda_g p_g}{z}\nabla p_g\right]+q_{ge}=\frac{\partial}{\partial t}\left(\frac{\phi S_g p_g}{z}\right) \tag{1}$$

and,

$$\nabla\left(\frac{\lambda_w}{B_w}\nabla p_w\right)+q_{we}=\frac{\partial}{\partial t}\left(\frac{\phi S_w}{B_w}\right) \tag{2}$$

The system of partial differential equations (equations 1 & 2) with auxiliary relationships and the appropriate boundary conditions and initial condition define a well-posed problem. The resulting system of non- linear equations from finite difference approximations is linearized with the aid of a fully implicit generalized Newton-Raphson iterative technique.

The Expected Deliverables

The expected deliverables from this study include:

- A coagulative analysis of the available reservoir analysis data and field data obtained by DOE in a manner that makes them more amenable to utilization and interpretation.

- A model that is coded and documented which will serve the primary purpose of a descriptive and predictive tool for natural gas production from tight blanket formations.

- An indepth analysis of the reservoir performance, productivity prediction, production decline curves under various production schemes with a view of devising the optimum production scheme for these formations.

## 6. RESULTS/ACCOMPLISHMENTS:

RESULTS

Application of Model to the Upper Cozzette Sand

In order to utilize the model to study the field case of interest, the upper Cozzette Blanket Sand, reservoir characterization parameters must be acquired. These parameters used to characterize the blanket sand are summarized in Table 1 [Branagan et al., 1984; Sandia, 1987, Corey 1954]. Available field data from the U.S. Department of Energy's Multiwell Experiment (MWX) provided the study area for this investigation. Three wells, between 110 and 215 ft. at measured depth, have been drilled near Rifle, Colorado, through the Mesaverde formation. Two of the wells, MWX-1 and MWX-2, penetrate the Cozzette blanket sandstone, which is the primary focus of this study.

Using this established set of reservoir and well parameters, a series of simulation runs were performed to "tune" the multi-mechanistic model (permeability being the "tuning" parameter) to actual production data from MWX-1, which was producing during this time. Although it is well-documented throughout the literature that this formation is highly anisotropic in permeability, the Cozzette was initially assumed to be isotropic and homogeneous. In this manner, the resulting "best-match" permeability is an effective permeability, making possible comparisons with the work of Branagan et al. (1984).

Figure 1 shows the comparison of the dual- and single-mechanism approaches. Basically it shows that the tighter the formation is, the more pronounced the contributions from the Fickian flow is. On the other hand, as the permeability increases, the Darcian contribution is dominant while the Fickian contribution becomes negligible. This demonstrates the viability of the dual-mechanistic approach in that it has the inherent capability to collapse to the conventional model as reservoir properties dictate. Other production runs made [Bezilla et al., 1989a,1989b ] also show that the single-mechanism approach underpredicts production and hence the dual-mechanism approach is of the essence.

The known anisotropic nature of the system was also considered by attempting to history-match the actual production data. Various ratios of $\frac{k_x}{k_y}$ which generate geometric mean permeabilities of 0.25 md were tested. As depicted in Figure 2, the "best-match" permeability contrast was determined to be $\frac{k_x}{k_y} = 10$, with $k_x = 0.8md$ and $k_y = 0.08md$.

Considering the rather limited data that was used in the aforementioned model refinement procedure, it was decided to test these "tuned" permeability values by performing a series of simulation runs attempting to match actual interference test data of the Upper Cozzette formation. In these runs, the previously determined values of permeability were chosen as a starting point. Furthermore, since MWX-1 had been on production for some time prior to the interference testing, the reservoir pressure had dropped to approximately 6024 psi; thus, this pressure was used in lieu of the initial reservoir pressure as given in Table 1.

**TABLE 1**

**Reservoir and Well Parameters for the Upper Cozzette Blanket Sand**

| | |
|---|---|
| Formation height, ft | 30 |
| Formation porosity, fraction | 0.069 |
| Formation water saturation, fraction | 0.40 |
| Reservoir temperature, °F | 230 |
| Gas viscosity, cp | 0.018 |
| Initial reservoir pressure, psia | 6300 |
| Critical water saturation, fraction | 0.25 |
| Critical gas saturation, fraction | 0.0 |
| Relative permeability to gas at $S_{wc}$, fraction | 1.0 |
| Relative permeability to water at $S_{gc}$, fraction | 1.0 |
| Vertical wellbore radius, in | 3.5 |
| Horizontal wellbore radius, in | 6.0 |
| Depth of formation, ft | 7855 |
| Relative permeability relationships: | Corey's Model |
| Permeability distribution ($k_x/k_y$), md/md | 0.125/0.01 |

Since the actual interference test data consists of as many as 600 individual measurements in a single day, an exact simulation of the actual data was not considered. This problem was circumvented by averaging the data over a specific time interval. For "matching" purposes, MWX-1 flow rate was used as input data to the model, and the model's prediction of MWX-1 bottom-hole pressure was compared to the actual MWX-1 bottom-hole pressure.

Using the "best-match" permeability distribution, a single-mechanism (i.e., Darcian flow only) simulation run was conducted to see if Fickian flow is indeed prevalent. The results, as shown in Figure 3, confirm the contribution of the Fickian flow, since the single-mechanism approach incorrectly predicts that the system would be depleted in approximately 11.8 days. There is good agreement between the actual and simulated data, thereby further confirming the "best-match" permeability distribution.

In order to bring into proper perspective the inadequacy of the strategy of adjusting permeability to match data, a series of simulation runs were conducted using the appropriate permeability distributions, thereby effecting a comparison of the predictive capabilities of the two approaches. The results of this study have been reported by Bezilla et al. (1989a, 1989b). The single-mechanism approach under-predicts recovery, by approximately 275 MMCF over a 10 year producing period for the 14.7 psia specification case and 200 MMCF for the 1000 psia case, even though the permeability distribution used had been "tuned" to match the interference test data.

## FIELD DEVELOPMENT STRATEGIES

A series of simulations was conducted to investigate the effects of well spacing and well type for the purpose of arriving at optimal production strategies for the Upper Cozzette blanket sand. The problems simulated were designed to be representative of actual field practice.

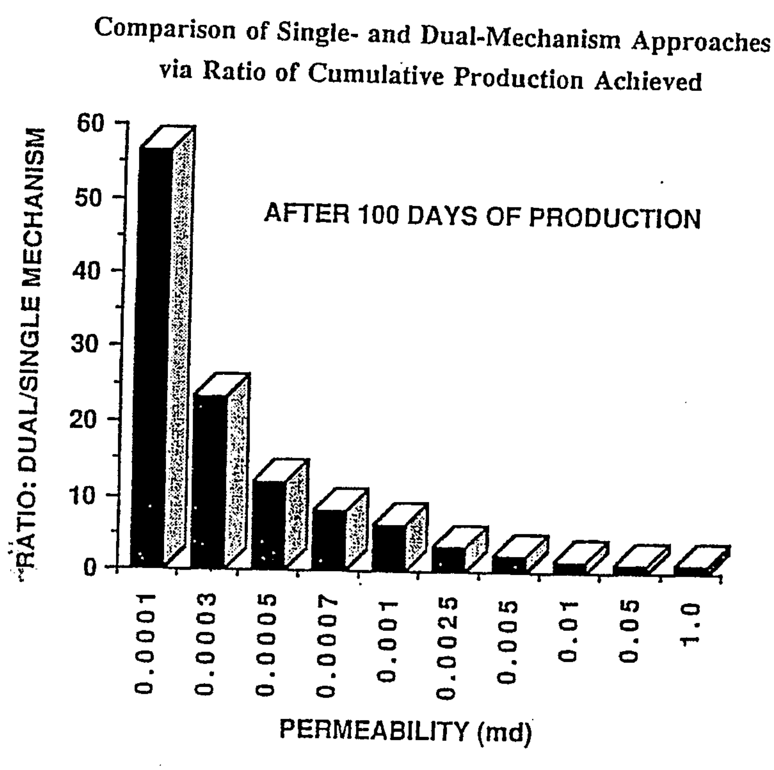



Figure 1. Comparison of single- and dual - mechanism approaches via ratio of cumulative production achieved ( $P_{wf}$ = 14.7 psia ).

Well Type and Spacing

A series of simulation runs was conducted to provide insight into the effects of well type and spacing on gas recovery. Three well types (unstimulated, vertically fractured, and horizontal) in conjunction with three spacings (80, 160, 320 acres) were investigated. For the vertical fracture simulations, two fracture lengths were examined (150 and 600 ft.), and for the horizontal borehole runs, two borehole lengths (600 and 1100) were considered. The results from this set of simulation runs are summarized in Table 2. In all the runs, an abandonment flow rate of 100 MCF/day was used. Of course, this abandonment condition is arbitrary and will depend upon the prevailing economics.

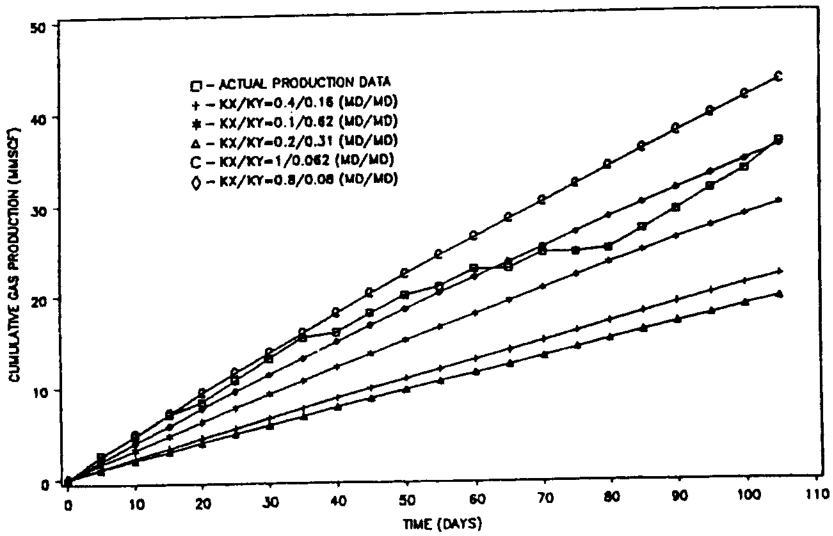



Figure 2. History matching of the Upper Cozzette production data by varying the permeability contrast ( $P_{wf}$ = 4200 psi during the production period ).

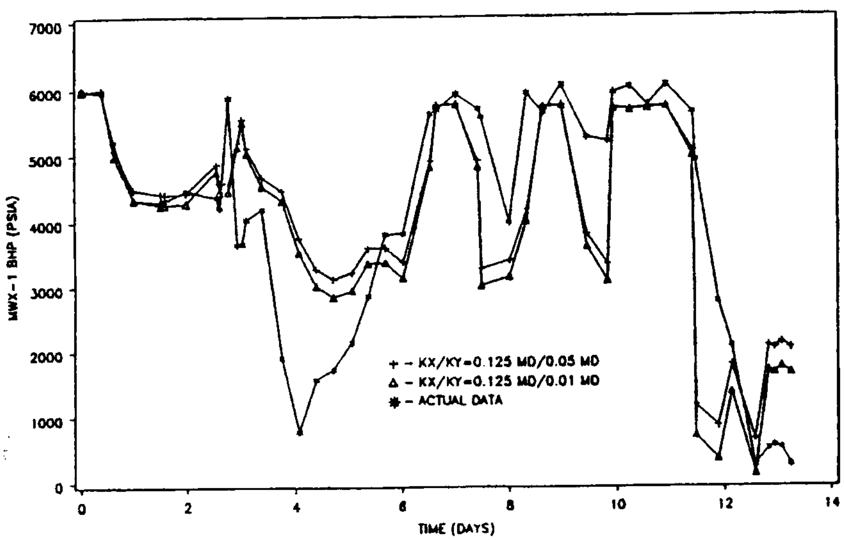



Figure 3. History matching of the Upper Cozzette interference test data using dual - mechanism approach.

As expected, the smallest well spacing considered (80 acres) yielded the highest fractional recovery for every well type considered. In all these runs, this well spacing also reached abandonment the earliest. Figures 4 through 6 express the projected recoveries as a function of both time and well spacing. Economics may dictate developing a field using a rather small well spacing, thereby maximizing gas recovery in the shortest time possible. However, higher well densities implies higher drilling costs, and the current market price of the gas must be able to support the chosen drilling program. On the other hand, if the current gas market is depressed, a viable field development strategy would be to use larger well spacings to reduce drilling costs and prolong the producing life of the reservoir.

TABLE 2

Impact of Well Type and Spacing on Gas Recovery

| Spacing (Acres) | Well Type | Total Recovery (MMCF) | Fractional Recovery | Abandonment* Time (Years) |
|---|---|---|---|---|
| 80 | Unstimulated | 502 | 0.165 | 8.0 |
| 80 | 150-ft VF** | 610 | 0.201 | 7.9 |
| 80 | 150-ft VF | 651 | 0.214 | 7.7 |
| 80 | 600-ft VF** | 720 | 0.237 | 7.1 |
| 80 | 600-ft VF | 762 | 0.251 | 6.3 |
| 80 | 600-ft HB | 679 | 0.224 | 7.2 |
| 80 | 1100-ft HB | 758 | 0.250 | 6.2 |
| 160 | Unstimulated | 974 | 0.160 | 15.7 |
| 160 | 150-ft VF** | 1153 | 0.190 | 16.1 |
| 160 | 150-ft VF | 1225 | 0.202 | 15.7 |
| 160 | 600-ft VF** | 1389 | 0.228 | 14.6 |
| 160 | 600-ft VF | 1467 | 0.241 | 13.4 |
| 160 | 600-ft HB | 1313 | 0.216 | 14.0 |
| 160 | 1100-ft HB | 1400 | 0.230 | 13.2 |
| 320 | Unstimulated | 1774 | 0.146 | 30.4 |
| 320 | 150-ft VF** | 2120 | 0.174 | 32.6 |
| 320 | 150-ft VF | 2247 | 0.185 | 31.9 |
| 320 | 600-ft VF** | 2532 | 0.209 | 27.6 |
| 320 | 600-ft VF | 2694 | 0.223 | 25.8 |
| 320 | 600-ft HB | 2237 | 0.185 | 23.1 |
| 320 | 1100-ft HB | 2259 | 0.186 | 20.8 |

* The abandonment criterion is a flow rate of 100 MCF/day.
** Perpendicular to the direction of maximum permeability.

### Stimulated Vertical Wells

The results of simulation studies conducted to determine the impact of stimulation jobs done using vertical fractures in vertical wells are summarized in Table 2. Well spacings examined include 80-acres, 160-acres, and 320-acres. In all these runs, the abandonment condition specified is a gas flow rate of 0.1 MMCFPD. For the unstimulated system, it takes approximately 16% of the original gas-in-place ($G_i = 3037$ MMCF). The stimulated wells were designed with two fracture lengths, 150 and 600 ft., and two fracture orientations for a given fracture length. the first is the case in which the fracture is oriented parallel to the direction of maximum permeability, while the other case is that in which the fracture is perpendicular to the direction of maximum permeability. While the latter is more desirable in terms of productive capacity, the former is more probable in actual field practice as the fracture tends to propagate in the direction of least resistance. It should be noted that the purpose of studying both orientations is not to determine which would produce more, but rather establish a bound on the vertical fracture's productive capacity. In practice, it is not easily feasible to control the direction of fracture orientation.

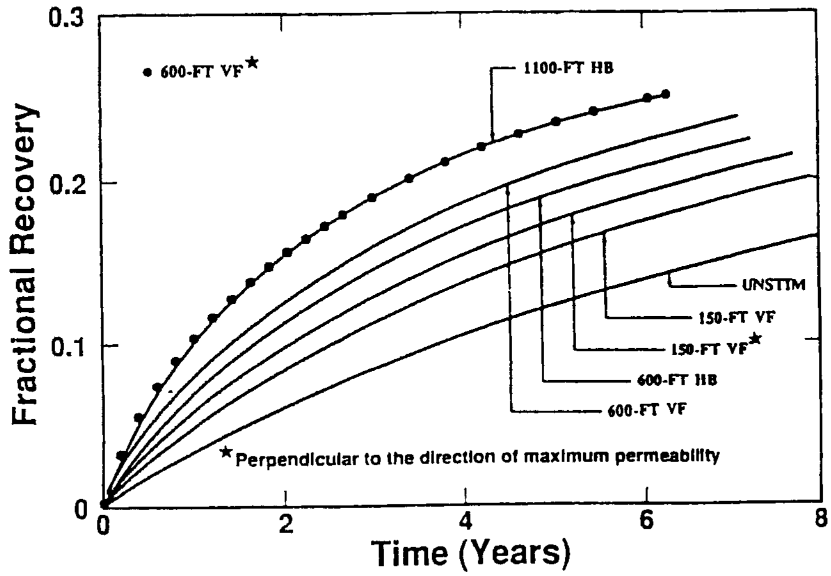



Figure 4. Impact of well type on gas recovery ( 80 - acre spacing ).

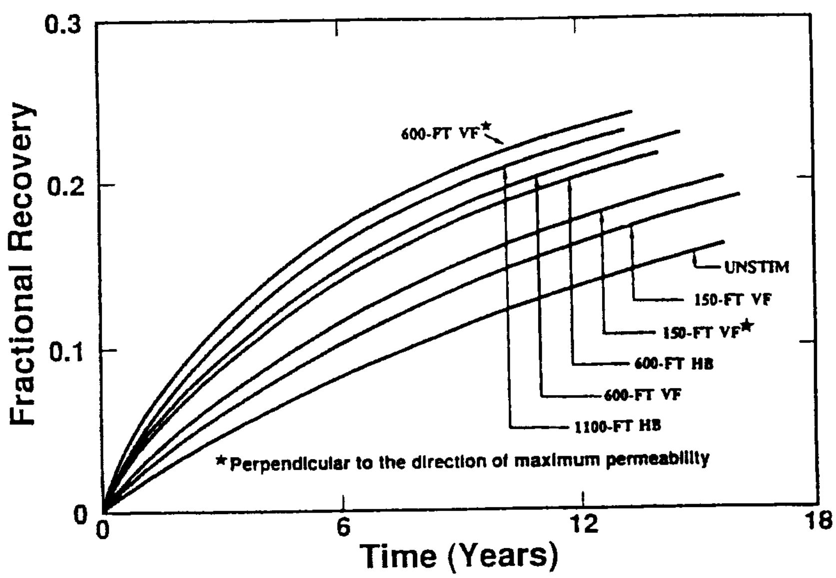



Figure 5. Impact of well type on gas recovery ( 160 - acre spacing )

As expected, the perpendicular orientation of the fracture (relative to the direction of maximum permeability) produces more than its parallel counterpart. (See Table 2 ). This disparity in realized production is slightly more pronounced for the 600-ft. vertical fracture and is likely due to its larger surface area available to the formation (36,000 $ft^2$ versus 9,000 $ft^2$ for the 150-ft. vertical fracture). The drainage effectiveness of the 600-ft. fracture is greater than that of the 150-ft. fracture and hence gives better recovery efficiency, both in terms of ultimate recovery and producing life. One observation that is worth mentioning is the fact that the time it takes to achieve essentially the same level of recovery is almost linear with well spacing for a given fracture length and orientation. The highest fractional recovery achieved was for the 80-acre spacing; however, the actual increase in fractional recovery with decreasing well spacing is quite marginal, from 0.223 for 320-acre spacing ($G_i$ = 12,107 MMCF) to 0.251 for 80-acre spacing ($G_i$ = 3037 MMCF). The real gain, however, is in the time required to obtain this recovery. Only 7 years is required for the 80-acre spacing as opposed to 28 years for the 320-acre spacing. Another interesting finding of this investigation is that the fractional recovery achieved with perpendicular orientation of the fracture is not dramatic (0.251 : 0.237 for the 600-ft. fracture/80-acre system and 0.223 : 0.209 for the 600-ft. fracture/320-acre system). The abandonment times for both cases are also comparable.

Horizontal Boreholes

As part of the development strategies for the Upper Cozzette blanket sand, horizontal boreholes, lengths 600 and 1100-ft. were also considered. Similar well spacings as for the vertical fractures were used. Again, the summary of the results are contained in Table 2. In all cases, the horizontal boreholes achieved substantially higher recoveries than unstimulated vertical wells. In the best case, as determined by fractional recoveries, the 600-ft. and 1100-ft. boreholes recovered 22.4% and 25.0% of the gas-in-place respectively, as compared to 16.5% for the unstimulated vertical well in an 80-acre system.

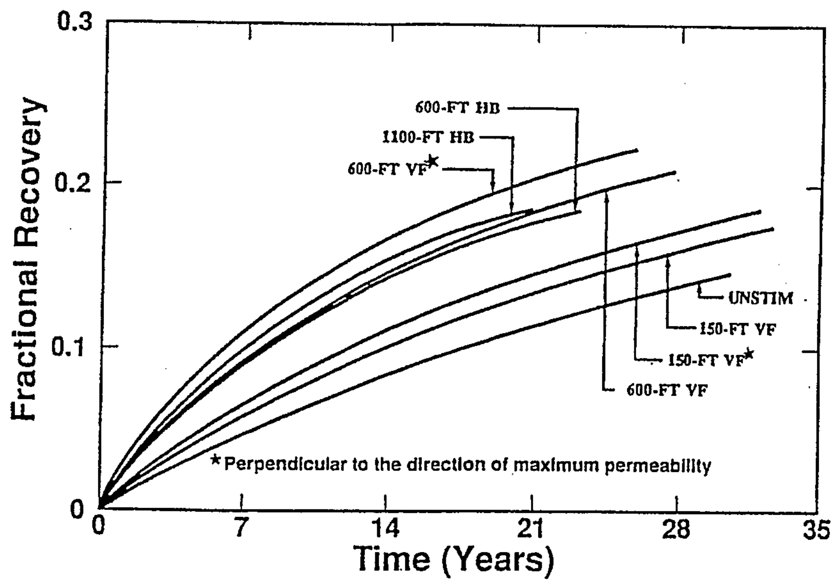



Figure 6. Impact of well type on gas recovery ( 320 - acre spacing )

In comparison with simulated vertical wells, it would appear from merely looking at the recovery numbers that the horizontal boreholes are out-performed by vertically fractured wells. This is shown in Figures 4 through 6, which provide comparisons of each of the various production strategies tested on a drainage area basis. However, such a comparison cannot be made solely on the basis of length of the fractures and horizontal boreholes since each present different areas of exposure to the formation. For instance, in the systems studied, the area exposed by the 600-ft. vertical fracture is about 36,000 square ft. (an idealized fracture spanning the entire thickness of the formation), versus an exposed surface area of only 1885 square ft. for the 600-ft. horizontal borehole. Clearly, other factors must be given consideration, such as the ability to actually achieve the desired fracture properties. With the advent of horizontal borehole technology, such concerns are minimal.

ACCOMPLISHMENTS

- Collected, collated the production data from the MWX test wells in the blanket sands of the Mesaverde formation.

• Analyzed data for permeability-porosity correlation.

• Conducted parametric study via history matching and decline curve analysis to obtain petrophysical properties needed in the model.

•Modified the multi-mechanistic model to make it amenable to the system under study. Modified model possesses necessary capability and numerical schemes to handle fractures, vertical and horizontal wells with different orientations and configurations.

• Utilized model to evaluate a number of production schemes.

• Conducted various studies relating to well pattern, heterogeneity/anisotropicity, stimulation.

## 7. FUTURE WORK:

• Complete the optimization studies and evolve the optimal production scheme.
• Document the optimization studies and evolve the optimal production scheme.
• Document code and compose the final report.

## 8. REFERENCES: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