SESSION 2A

EASTERN GAS SHALES RESEARCH

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Albert B. Yost II
Morgantown Energy Technology Center

ABSTRACT

Eastern Gas Shales research focuses on the development of the scientific and engineering knowledge base on natural gas recovery from shale formations that underlie the Appalachian, Illinois, and Michigan Basins. This research is an integral part of the Unconventional Gas Recovery activity, which is a multidisciplinary effort sponsored by the U.S. Department of Energy (DOE) to quantify where future gas reserves can be found.

To date research has been successful in characterizing the geology, geochemistry, and resource magnitude of the Appalachian Basin, and in defining the gas-producing mechanism and drainage pattern in an established area of production near the middle of the basin. In addition, an offset well test in Ohio (two wells offset to a producing well) established reservoir flow behavior and identified the potential for infill drilling of existing shale gas fields. Infill drilling may be a cost-effective strategy to exploit gas resources within known producing areas. In areas of established production (eastern Kentucky, southern and western West Virginia, and southern Ohio), the 3 trillion cubic feet (Tcf) produced to date could be increased thirtyfold without further exploration.

Recently, research was completed on the acquisition of fundamental reservoir properties from wells of opportunity and on the installation of a second offset well site in Kentucky for understanding reservoir flow behavior. This research entailed gathering reservoir property data from 10 sites that have favorable geology and geochemistry in areas of nonestablished production. This information will quantify the magnitude of matrix and fracture porosity, permeability and reservoir anisotropy, and will improve the ability to quantify technically recoverable resources for these areas of unknown potential.

Concurrently, research was completed on activities to increase recovery efficiency from a directionally drilled well in an area of historical production; wherein, less than 10 percent of the available gas in place is typically produced by stimulated vertical wells. Analysis of shale gas production mechanisms indicated that an increase in the amount of shale

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surface area connected to the borehole may result in more of the adsorbed gas being released and produced over the entire life of the well. Increased recovery efficiency is thought to be achievable by using a directionally deviated well that can be designed to cross natural fractures and can be stimulated to increase the surface area in contact with the borehole. An existing reservoir model (SUGAR-MD) has been modified to simulate the expected performance of stimulated, deviated wells. The drilling, coring, logging, and testing of a directionally deviated well is a major field verification effort that measures the key reservoir properties (natural fracture spacing, in situ stress, productive interval, formation permeability, and porosity) that are used in the simulator. These activities also measure the productivity improvement over that of stimulated vertical wells in the area (available baseline data). Results could provide important guidelines for industry that may augment gas recovery efficiency by using infill drilling and more efficient production practices.

RECOVERY EFFICIENCY TEST

1. CONTRACT NUMBER: DE-AC21-85MC22002

CONTRACTOR: BDM Engineering Services Company
1199 Van Voorhis Road, Suite 4
Morgantown, WV 26505
(304) 598-2666

CONTRACT PROJECT MANAGER: William K. Overbey, Jr.

PRINCIPAL INVESTIGATORS: William K. Overbey, Jr.
C. David Locke

METC PROJECT MANAGER: Albert B. Yost II

PERIOD OF PERFORMANCE: September 30, 1985 through February 28, 1989

2. SCHEDULE/MILESTONES:

1988 Project Schedule

	J	F	M	A	M	J	J	A	S	O	N	D	J	F
Frac Zone #1 - Foam/proppant	—													
Test and Analysis of Frac Job	—	—	—	—										
Frac Zones 2-3 and 4					—									
Test and Analysis of Frac Job						—	—							
Frac Zones 5 and 8								—						
Test and Analysis of Frac Job								—	—					
Clean Up Well - Test - Place in Production									—	—	—			
Final Report											—	—	—	—

3. OBJECTIVES:

The objective of this project was to determine the increased recovery efficiency of a long horizontal wellbore drilled in the fractured Devonian shale reservoir over that of a conventional vertical well drilled in the same area. A second objective was to determine the improvement in production efficiency of a stimulated horizontal well over that of a stimulated vertical well in the area. A third objective was to determine if multiple natural fracture trends encountered by the horizontal wellbore could be inflated, extended and propped open during hydraulic fracturing operations.

4. BACKGROUND STATEMENT:

The U.S. Department of Interior, Bureau of Mines, Morgantown Energy Research Center initiated studies of fractured oil and gas reservoirs in the Appalachian region in 1964. Results of these early studies pointed out that the earth's natural fracture system played a major role in the flow of fluids from oil and gas reservoirs.

In 1976, the Energy Research and Development Administration's (ERDA) Morgantown Energy Research Laboratory (successor to U.S. Bureau of Mines) initiated the Eastern Gas Shales Project. This project was designed to characterize the Devonian-age shales in the east, determine the total gas resource in place, and to investigate new techniques for improving recovery of the gas in place. The U.S. Department of Energy (successor to ERDA) has completed the tasks of resource characterization and presently pursues research directed to improving the efficiency of recovery of gas from the shales. The present project is a continuation of studies initiated in 1968. The first directional well test was drilled in September and October, 1972, in Harvey District, Mingo County, West Virginia, in a cooperative project with Columbia Gas. The well was targeted to reach an inclination of 60°, but only obtained a deviation of 42°. The second test was conducted in 1976 in cooperation with Consolidated Natural Gas (CNG) in Jackson County, West Virginia, and obtained an inclination of 52°. The third test was conducted in Meigs County, Ohio, in 1982. Again, the target inclination was 60°, but only 25° was obtained in this test.

5. PROJECT DESCRIPTION:

INTRODUCTION

The U.S. Department of Energy's Morgantown Energy Technology Center awarded The BDM Corporation a contract in September 1985 to select an area within the productive areas of Devonian shale production; pick a specific site; prepare a specific drilling plan; drill, core, log, test, stimulate and evaluate the recovery efficiency of the well. The following is an account of work performed under this contract.

Phase I Operations Summary

During Phase I operations, a basin analysis of geologic and engineering factors controlling production was conducted to determine which geologic province would provide the best opportunity to drill a horizontal well that would encounter a significant number of natural fractures and, subsequently, good gas production. The area selected was Cabell, Wayne and Lincoln Counties, West Virginia. Site selection studies conducted in these three counties led to the selection of a site in Lincoln District, Wayne County, owned by Cabot Oil and Gas Company. Cabot agreed to cooperate with BDM and DOE in making acreage and production and geologic data available for use in the project.

Remote sensing studies of the lease located lineaments which were oriented parallel or subparallel to regional joint trends and the validity of these lineaments was confirmed by resistivity surveys across the mapped lineaments. Three potential locations were submitted with recommendations for approval of one to DOE. The final location and orientation was selected by DOE.

A computer program was obtained that was used in sizing the rig and assisting in other phases of the well-planning operations. The original proposal to drill a small diameter hole and then ream it out was abandoned in favor of the more cost-effective plan of using large diameter drilling tools which had more stable drilling characteristics. The plan, as revised and approved by DOE, was to drill at a constant 4.5°/100' rate of angle build using downhole motors and air-mist drilling liquid to an 85 degree inclination, then set a hole protection string to insure that we did not lose the hole completed to that point. The plan was then to drill out of the casing to the target 90° inclination, then take 90 feet of oriented core before drilling the balance of a 2000-foot long horizontal section and logging the well.

Actual drilling operations proceeded as planned, until a depth of 3459 feet was reached and the drill string stuck while reaming the hole. We used a shot inside the drill string to back off of the 2 collars, bit and reamers, picked up a set of hydraulic jars, and tried to work the drill string loose for 12 hours before deciding to sidetrack the hole. We pulled back up to 3200 feet and cemented the old hole and kicked off again. On the second try, we built angle too quickly and were going to come in about 20 feet higher than the target zone. We elected to sidetrack again to be able to hit the target zone when we had reached 3600 feet.

After the sidetrack, which was accomplished again at 3200 feet, drilling proceeded on the planned trajectory, but at an inclination of 74 degrees we were having a severe problem with lifting the cuttings out of the hole and decided to set the hole protection casing string at that point and then proceed. The 8-5/8 inch hole protection string was cemented at a depth of 3803 feet and a bent housing motor was employed to drill the remaining 16 degrees of inclination.

When the borehole had obtained 90 degrees inclination, three core barrels of oriented core was obtained. Two were drilled, one after the other, then we drilled ahead 100 feet before taking the last 30 feet of core. In the last core run, we cut a fault zone and obtained complete core of the faults and associated fractures, which was about 2 feet wide. This was the first air-drilled rotary core ever taken in a horizontal well.

When air rotary drilling operations resumed after coring, a slightly building BHA was used to offset the effects of gravity, and the well was allowed to drop angle at the rate of 1/4 degree per 100 feet.

This was maintained until the entire 2000 feet of horizontal section was completed. When completed on December 18, 1986, this was the longest air-drilled horizontal well in both the United States and the world.

When total measured depth (TMD) of 6020 feet was reached, the hole was logged by Dresser Atlas by pushing logging tools in on the drill string. Gamma ray, density, dual induction, caliper and temperature logs were run on two logging runs. A third logging run was made with a borehole television camera attached. This was the first time a TV camera was used to log a horizontal well (and quite successfully). More than 200 wellbore fractures were detected and oriented after extensive analysis of the log and development of an analytical technique which was tested with surface models and jigs.

After the logging operations were completed, the logs were examined to select the locations of the external casing packers (ECPs) and the port collars which would make up the unique "open hole" type completion (also a first-ever for a horizontal well).

The external casing packers and ported collars were installed in the 4-1/2 inch casing string to a total measured depth of 6017 feet. The well was then open-flow tested for 3 months before the ECPs were inflated and pressure tested. Seven of the eight ECPs installed functioned properly and we had successfully partitioned the well into 7 intervals varying from 91 feet to 649 feet in length. Each zone was subjected to a pressure build-up and flow test, permeability of each zone was estimated, and skin factor determined for the entire well.

This completed the world-record-setting Phase I operations of the Recovery Efficiency Test.

Phase II Operations Summary

Phase II operations began with preparation of a stimulation rationale and plan which included conducting an initial "mini frac" to obtain data for stimulation design. BDM had proposed to conduct 4 stimulations in the well, then to evaluate those and make recommendations for any additional stimulations that might be required. A rationale was developed and approved which examined fluid types (gases, liquids, foams), injected volumes (low versus high), and injection rates (low versus high) over the four stimulations planned and included an evaluation and final major frac job on the balance of the well.

The mini-frac data revealed that we had a lower than anticipated fracture gradient and fracture closure pressure. Closure pressure of 850 and 1050 were determined for Zone 6 where the test was conducted. Later on, when Zone 1 was stimulated, a lower closure pressure of 760 psi was measured. The detection of multiple closure pressures was considered prima facie evidence that multiple natural fractures had been inflated which was a primary goal of the completion (open-hole) and stimulation programs (low injection rates).

The first stimulation was conducted in Zone 1 and was a nitrogen gas frac without proppant injected at low rates to inflate the 69 or so natural fractures detected on the borehole TV camera. Collection of bottomhole pressure data during and after the frac job indicated 3 separate closure pressures in Zone 1 which BDM interpreted to be due to fractures with different orientations with respect to present principal stress orientation. Flowing to clean up the gas and subsequent pressure build-up and drawdown tests revealed that the fractures opened up during the low injection rate stimulation, but completely closed up within 22 days, and the zone returned to its original pre-frac production rate. This left us with the first major finding of Phase II, which was that nearly stress relieved reservoirs may require proppant in fractures to maintain production conduits. This resulted in a revision of the test plan rationale to take advantage of the unique opportunity to conduct three stimulations using different fluids and different diagnostics experiments. The attempt to use tiltmeters to detect the orientation of induced fractures failed because of installation problems which could not be rectified.

The second stimulation in Zone 1 consisted of liquid CO_2 fluid pumped at 10 and 20 bbls/minute with two different radioactive tracers to determine where the fractures were exiting the borehole. Evaluation of the tracer logs revealed that CO_2 was a very efficient frac fluid and had interconnected 16 natural fractures in Zone 1 with natural fractures in adjacent Zones 2-3 and 4 (see Table 1 for a summary of fracture diagnostics tests).

Table 1. Summary of Fracture Diagnostics Tests

TEST NUMBER	ZONE	NATURAL FRACTURES DETECTED	FRACTURES PUMPED INTO	PRODUCTION IMPROVEMENT
1	6	6	6*	4.1
2	6	6	6*	4.1
3	6	6	14**	4.1
4	6	6	14**	4.1
5	1	69	12***	5.0
6	1	69	27 (over 4 zones: 1,2,3,4)***	25.0
7	1	69	67 (over 4 zones: 1,2,3,4)***	25.0
8	1	69	17 (over 3 zones: 1,2,3)***	15.5
9	1	69	69 (over 4 zones: 1,2,3,4)***	15.5
10	2-3, 4	72	No Tracers	3.1
11	2-3, 4	72	54 (over 3 zones: 2,3,4)***	3.1
12	5, 8	65	No Tracers	6.0
13	5, 8	65	No Tracers	6.0

* Based on camera.
** Based on tracer logs.
*** Observed from Test 6.

It was determined that higher injection rates tend to cluster fractures and that injection points moved up and down the wellbore as stresses from fluid loading of the fractures built up and caused shifting to areas of lower stresses. Again a rapid decline of production rate from 50 mcfpd back to the original 2.2 mcfpd in 40 days indicated the need for proppant.

The indications of fracture communications was tested by conducting a series of pressure build-up and drawdown tests in each of the zones. In addition, gas samples were collected from each zone and analysis revealed that Zones 2-3 and 4 which had not been stimulated contained CO_2 and NO_2 contents at 10 to 30 times the normal concentrations, thus lending support to the theory that fractures exited the wellbore in Zone 1 and came back to the wellbore in Zones 2-3 and 4.

The third stimulation in Zone 1 was a low volume, low rate nitrogen foam frac with sand proppant to keep inflated fractures propped open. The volume consisted of only 30,000 gallons of foam and 20,000 pounds of sand, but resulted in a 15-fold increase in flow rate which had very little decline over a period of 40 days. The interconnection of fractures in Zone 1 with Zones 2-3 and 4 were demonstrated when Zones 2-3, 4, 5, 6, and 8 were opened to flow up the annulus, causing the Zone 1 production rate to drop from 35 mcfpd to 20 mcfpd, then stabilizing at 25 mcfpd or 70 percent of the original flow rate. This is the first documented zone interference testing ever conducted in a horizontal well. The fracture diagnostics test which showed multiple hydraulic fractures being propagated during a single pumping event is also a world's first demonstration. This is also believed to be the first use of radioactive tracers in a horizontal well for fracture diagnostics purposes.

After evaluation of the three stimulations in Zone 1, it was determined to conduct a large volume, high rate stimulation in Zones 2-3 and 4 which are the best producing zones in the well. These zones were stimulated with 138,000 gallons of foam and 250,000 pounds of sand. A single radioactive tracer was used in the proppant stage to indicate that 54 fractures were pumped into during the stage. Production was fairly stable at a rate of 62 mcfpd for more than 60 days, but after being shut-in 14 days for a pressure build-up test, production rate declined to 42 mcfpd, a decline of 33 percent. No valid explanation of this behavior was determined by BDM.

The final frac job was conducted in Zones 5 and 8 but with a slightly smaller volume, but at a higher rate. The frac, consisting of 105,000 gallons of nitrogen foam and 150,000 pounds of sand, was pumped at 50 barrels per minute (see Table 2 for a summary of stimulation tests). Flowback tests after this stimulation revealed a fairly constant rate of 62 mcf for several days before the well was shut-in for a pressure build-up test. Results of well testing analysis revealed that permeability (flow capacity) of each zone stimulated was improved considerably (see Figure 1). The highest improvement ratio was 4:1 in Zones 5 and 8.

After the build-up test, the entire well was placed on production which started out at 155 mcfpd, but declined over the next six weeks to 90 mcfpd (see Figure 2).

Table 2. Summary of Stimulation Test Series Conducted on RET #1

TEST NO.	ZONE	FLUID	RATE	VOLUME	FRAC DIAGNOSTICS
1	6	N_2 (Gas)	5 bpm	37 mcf	None
2	6	N_2 (Gas)	15 bpm	212 mcf	None
3	6	N_2 Foam	5 bpm	100 bbls	Scandium 46
4	6	N_2 Foam	12 bpm	300 bbls	Iodine 131
5	1	N_2 (Gas)	8-16 bpm	1600 mcf	Tilt Meters
6	1	CO_2 (Liquid)	12 bpm	200 bbls*	Iodine 131
7	1	CO_2 (Liquid)	20 bpm	400 bbls*	Scandium 46
8	1	N_2 Foam Pad	10 bpm	166 bbls	Antimony 124
9	1	N_2 Foam/Proppant (20,000 lbs 20/40)	10 bpm	595 bbls	Iridium 192
10	2-3,4	N_2 Foam Pad	40 bpm	905 bbls	None
11	2-3, 4	N_2 Foam Pad (225,000 lbs 20/40)	30 bpm	2142 bbls	Scandium 46
12	5 & 8	N_2 Foam Pad	25 bpm	530 bbls	None
13	5 & 8	N_2 Foam/Proppant (150,000 lbs 20/40)	50 bpm	2500 bbls	None

* Surface Volume

Phase II operations concluded successfully when the well was turned over to the operator for production operations. Phase II operations demonstrated the idea of inducing multiple hydraulic fractures from a horizontal wellbore and various methods of testing and cleaning out a horizontal well.

Economic Analysis

The purpose of this project was to determine the recovery efficiency of a horizontal well when compared with a vertical well, both natural and stimulated production. BDM Engineering Services Company was successful in demonstrating that a horizontal well could be drilled and successfully stimulated five times. Gas production is projected to exceed that of a vertical well drilled in the same area by a factor of about 6 to 7.

A review and analysis of the production projections for the well in light of the costs of this well, which was a research well, would not be very meaningful. There are many costs encumbered in a research well which would not be encumbered in a commercial well. Therefore, BDMESC compiled a set of costs which excluded the research costs as a baseline for projecting economics based on this well. Table #3 lists the major cost elements and their costs for the RET #1 had it been a commercial well.

Figure 3 shows the first 2-1/2 months of actual production and the production projected on the basis of reservoir parameters derived from the testing program.

Table 3. Projected Costs for a Commercial RET #1 Well

ITEM	1986 RET #1 Cost	1988 Projected Costs
Drill Rig	$ 277,920	$ 219,310
Directional Services	169,912	83,243
Other Direct Costs	96,349	61,835
Logging	41,248	28,600
Casing & Completion Equipment	145,223	119,184
Cementing	10,998	16,400
Stimulation	283,826	220,000
TOTAL COSTS:	$1,025,476	$ 748,572*

* Costs for a 6000 foot well drilled at 8°/100' rate of angle build over a period of 35 days and 4 frac jobs being conducted on the well.

The G3DFR model which was used to evaluate the potential production from the location prior to drilling the Recovery Efficiency Test #1 well was also used to predict production of the well after drilling and stimulation was completed. Figure 4 projects 20 year cumulative production for the RET #1 well utilizing parameters developed from well testing of 180 psia pressure. Using the full reservoir thickness of 247 feet as productive reservoir, we found that we had to reduce the permeability to an average of 0.09 md to match the current rate of production. Sensitivity of cumulative production to minor changes in permeability and permeability anisotropy is presented in Figures 5 and 6. This indicates that there are most likely heterogeneities in the fracture system and that the flow path to the wellbore is not uniform. It is likely that fracture permeability changes with time as fractures slowly close as pressure declines with production. A comparison of pre- and post-drilling estimates of 20 year cumulative production is presented in Figure 7. The major difference in the curves is a function of an assumed pressure of 350 psia versus the actual pressure encountered of 180 psia.

The DOE/BDM/Eneger horizontal well cost $170.00 per foot to drill and complete when only necessary third-party costs are considered. BDMESC believes that by doubling the turning rate and effecting other savings, these costs for a horizontal well can be reduced to $100 to $110/foot.

Using the same data, we calculate that a well inclined to 70 degrees can be drilled for $88 per foot, so there is not much difference in cost between a 70° inclined hole and a well drilled out to 90 degrees. According to our estimates, a 6000 foot vertical well can be drilled, completed, and placed in production in the Appalachian Basin for $30 per foot.

Figure 8 presents the anticipated internal rate of return on investment for horizontal wells in 3 different cost ranges at the current price of \$2/mcf for gas. The amount of gas required to be produced over a 10 year period for payout ranges from 400 to 520 mmcf.

Since Devonian shale wells are known to produce from 50 to 100 years, projecting a 10 year payout for a well that could produce 1 to 3 bcf is not unreasonable. Developing all aspects of the technology to the level where risks are considered acceptable will require the drilling and producing of a number of wells.

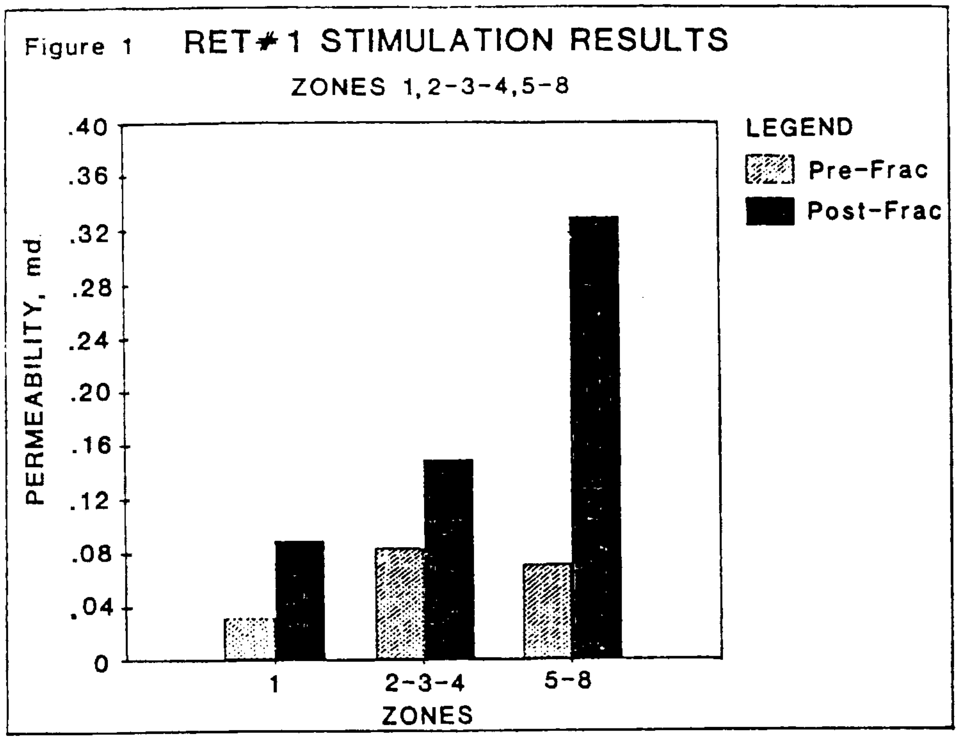
This concept of horizontal drilling represents a major contribution to drilling, completion, and stimulation of unconventional gas resources which will improve the likelihood of recovery of additional resources from the Devonian shale.

6. ACCOMPLISHMENTS

- Successfully drilled and completed the first and longest air-drilled horizontal well in the world.
- Developed a methodology for analysis of video camera surveys of borehole to determine frequency distribution and orientation of natural fractures in a horizontal wellbore.
- Designed and demonstrated a new openhole completion methodology using external casing packers and ported collars in the casing string with application potential in conventional reservoirs as well as low pressured unconventional reservoirs (horizontal well technology).
- Developed the concept and demonstrated the methodology of inducing multiple hydraulic fractures from a horizontal wellbore during a single pumping event.
- Demonstrated the economic and commercial viability of the horizontal well concept in a fractured Devonian shale reservoir.

7. FUTURE PLANS

Conduct additional demonstrations of the horizontal well technology under other geologic and reservoir conditions.



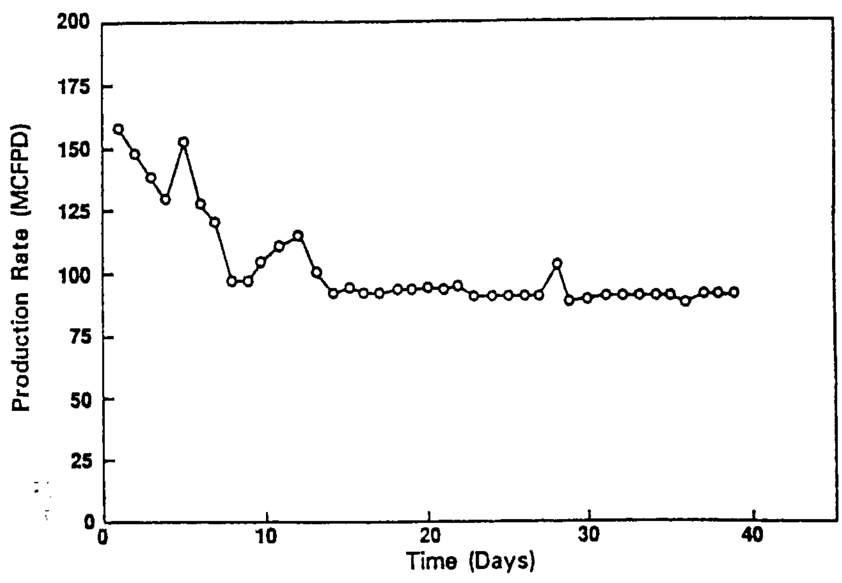


Figure 2 **Production Rate History**
Post Stimulation RET 1

Figure 3

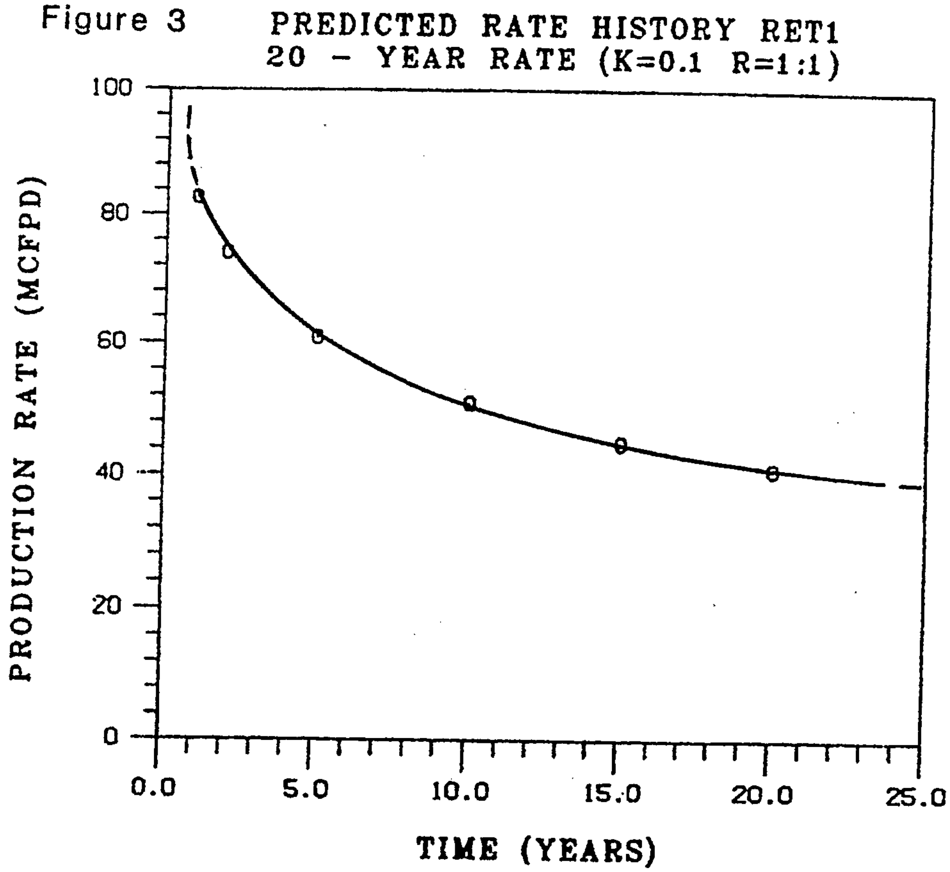


Figure 4

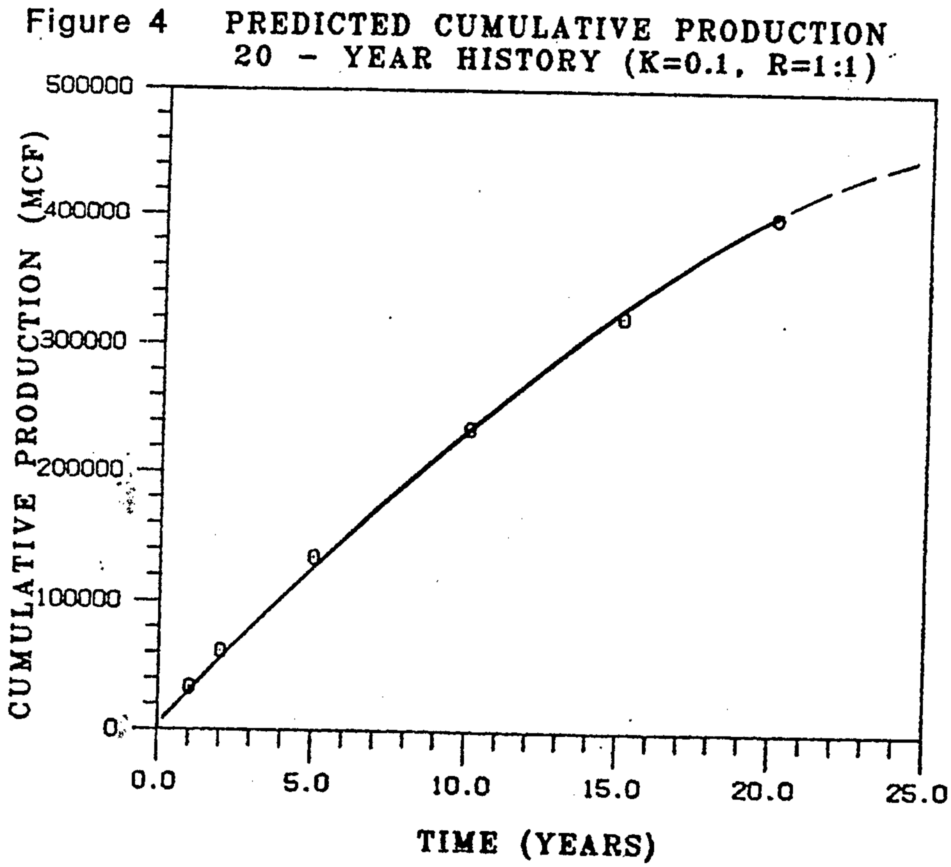


Figure 5 PROJECTED PRODUCTION AS FUNCTION OF PERM
20 - YEAR PRODUCTION HISTORY RET#1

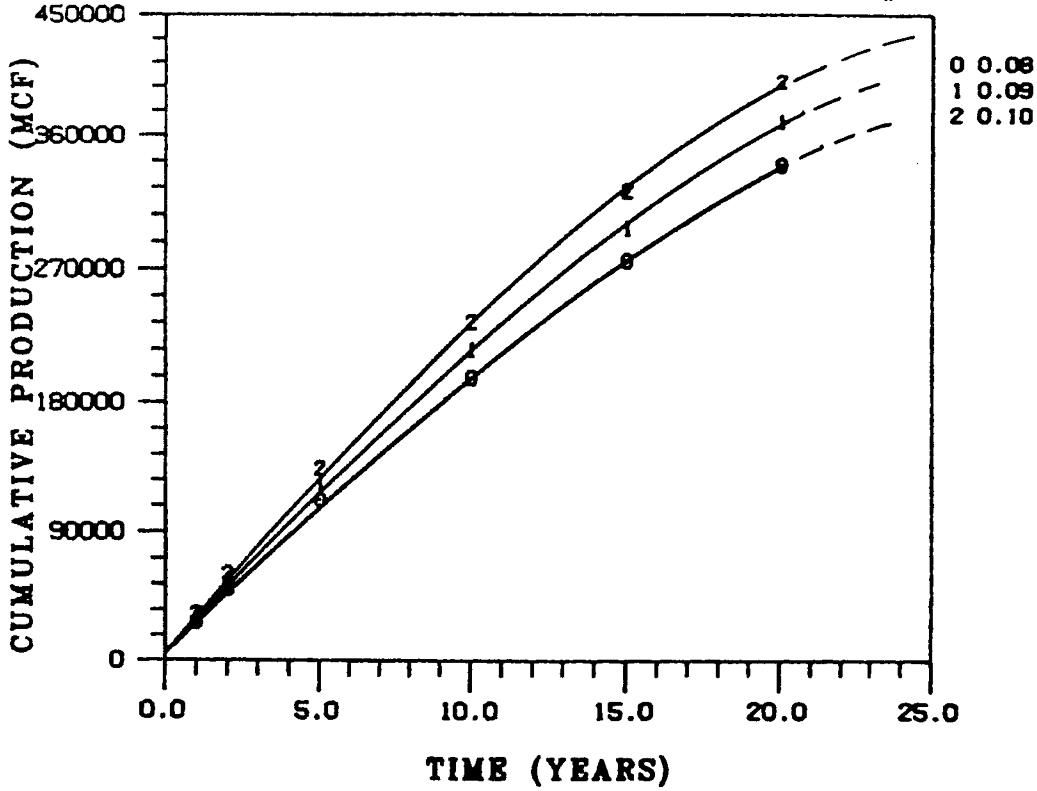


Figure 6

PROJECTED CUM PRODUCTION BASED ON Kx:Ky RATIOS
20 - YEAR HISTORY (K= 0.10 md, P=180 psia)

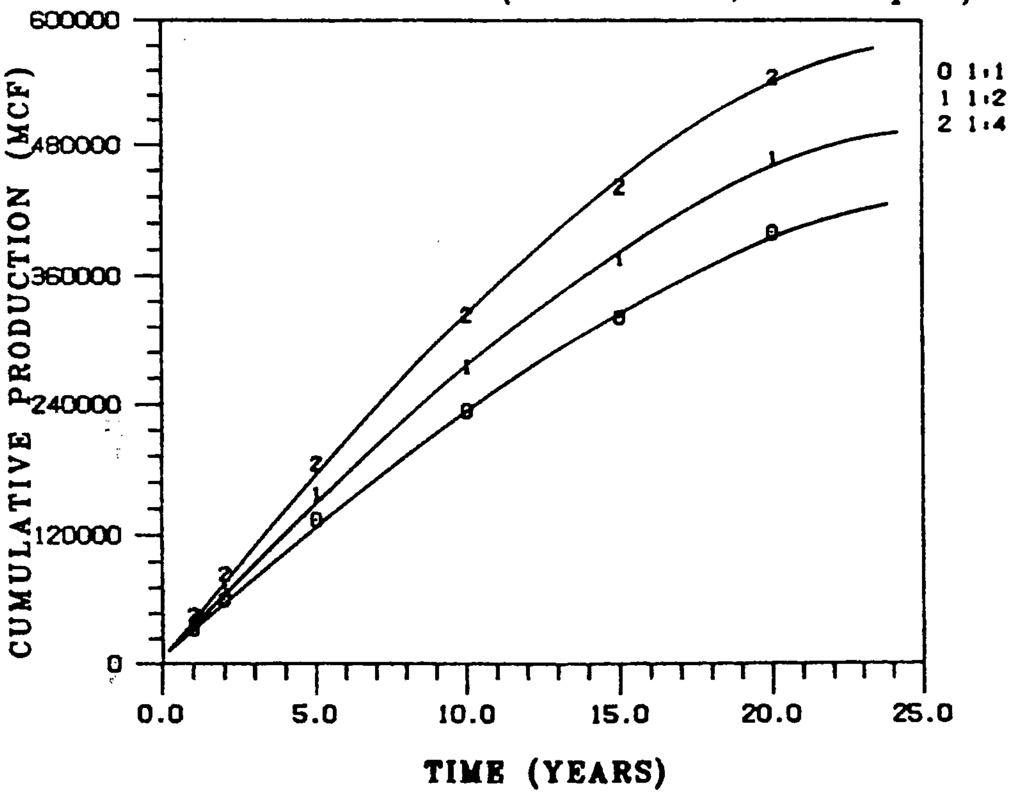


Figure 7

PRE and POST DRILLING PRODUCTION PREDICTION

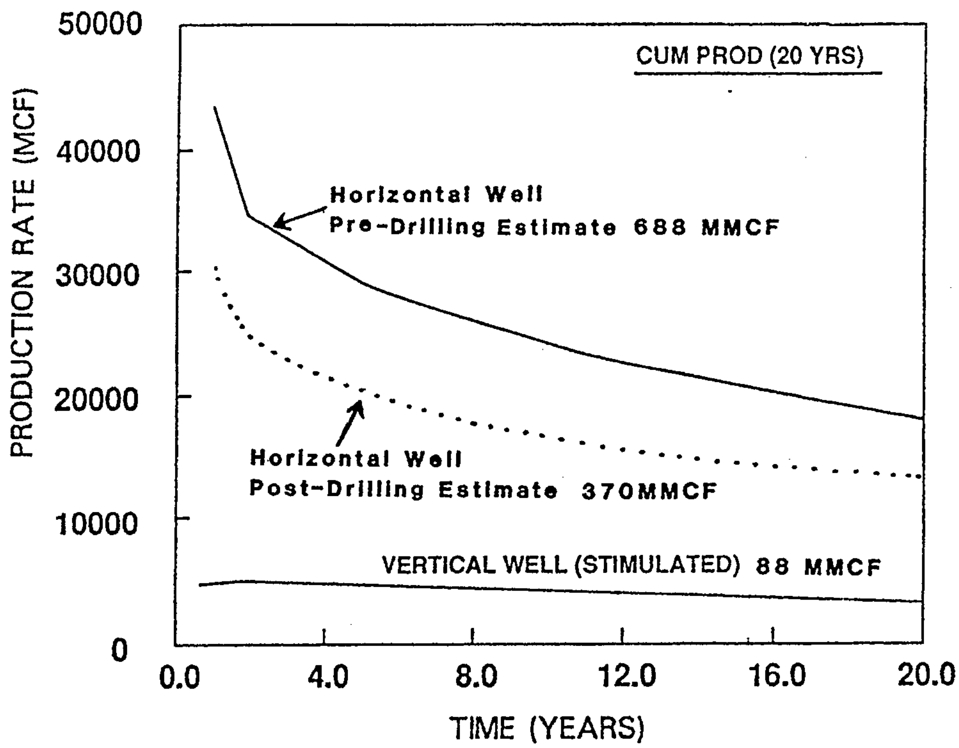
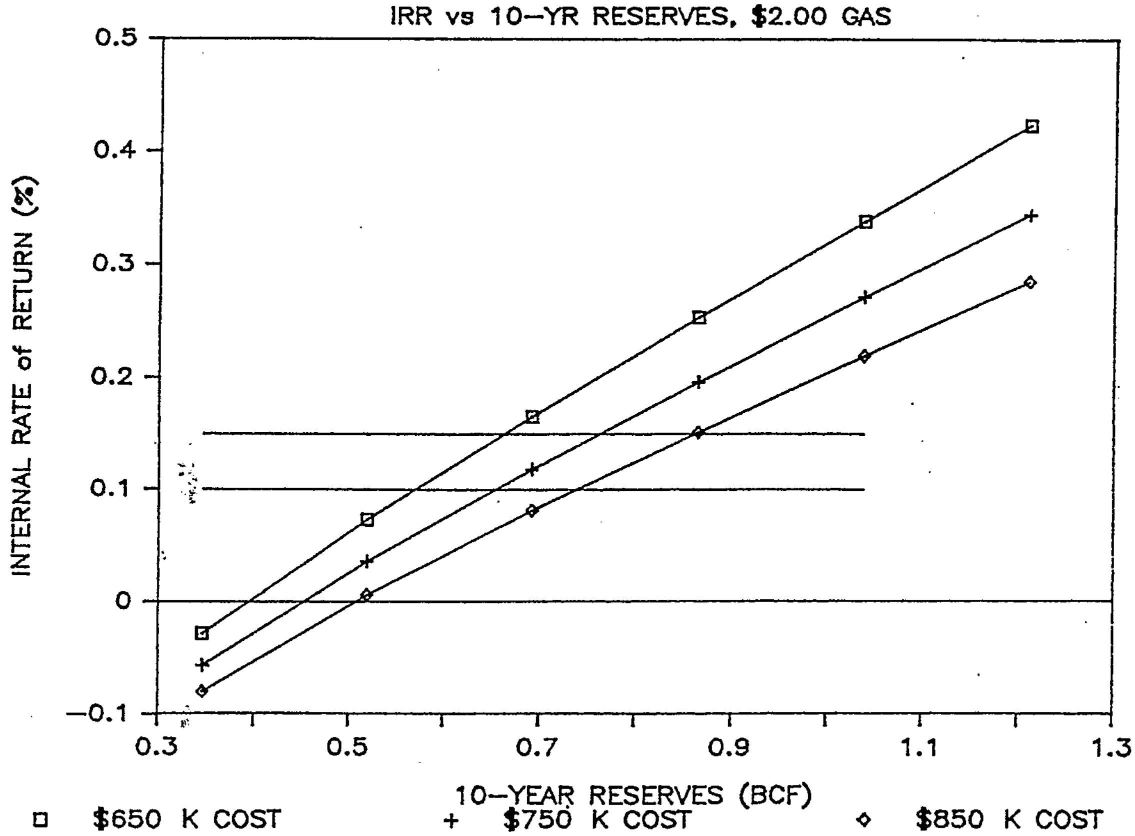


Figure 8 HORIZONTAL WELL ECONOMICS

IRR vs 10–YR RESERVES, $2.00 GAS



UPCOMING PLANS FOR THE DOE/STERLING/GRI/COLUMBIA SLANT WELL PROJECT

By Gery Muncey

CONTRACT NUMBER: DE-FC21-88MC25146

CONTRACTOR: Sterling Drilling and Production Company

150 Grand Street, Fourth Floor

White Plains, N.Y. 10601

CONTRACTOR PROGRAM MANAGER: Charles E. Drimal, Jr.

PRINCIPAL INVESTIGATORS: The United States Department of Energy

Sterling Drilling and Production Company

The Gas Research Institute

METC PROGRAM MANAGER: Albert B. Yost, II.

CONTRACT PERIOD OF PERFORMANCE: December 1, 1988 - March 31, 1990

Program Schedule

	D J F M A M J J A S O N D J F
I. Well Site Planning	
1. Site Selection	----
2. Site Selection Topical Report	------
3. Lease Identification	----
4. Site Acquisition/Preparation	------
II. Well Bore Installation, Stimulation, and Production Monitoring	
1. Work Plan Development	----
2. High -angle Drilling	---
3. Logging	---
4. Well Testing and Analysis-	------
5. Stimulations	---
6. Final Project Report	---
7. Production History Monitoring	----------

ridor correlates strongly with interpreted thrust fault traces. Faults which cut the Devonian section are interpreted to die out in an area approximately coincident with the mapped zone of high-production potential. Wellswhich are very close to or are cut by faults tend to exhibit higher initial production rates and cumulative production potential. The highest production potentials are exhibited by wells near interpreted strike-slip faults, especially those which cut the Java Formation (Lowery et al, 1986). Note also the proximity of wells which produce liquids to interpreted thrust fault traces and zones of strike-slip faulting.

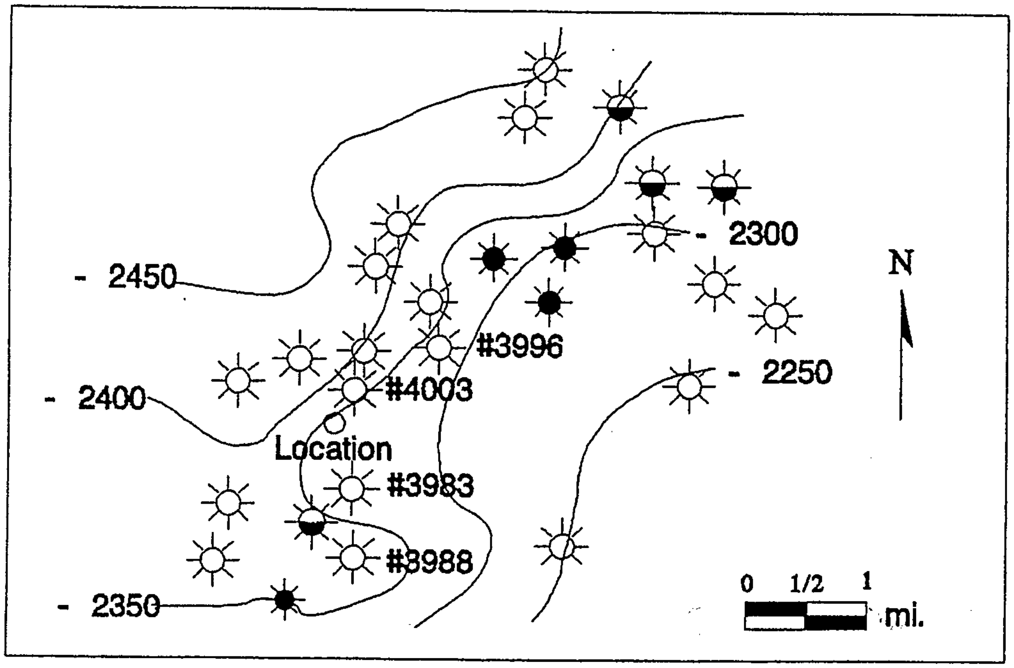


Figure 2. Top of The Lower Huron

It is clear that significantly increased production potential at or near fault traces, fault terminations, and/or within zones of interpreted strike-slip faulting is associated with locally increased fracture density. Increased fracture density in these areas is believed to be contributed to by displacement transfer near fault terminations which is necessary to maintain approximately uniform shortening along the faulted region (see House and Gray, 1986). Displacement transfer via small-scale folding and fracturing is expected. Rollover folds are anticipated to be an important mode of displacement transfer at fault terminations, and drag folds are expected to have developed in areas influenced by strike-slip faulting. In either case, folding will probably have occurred via flexural-slip with concomitant extensional fracturing.

Unanimous agreement does not yet exist regarding the predominant structural style of the wellsite and surrounding area. Both high-angle reverse faulting and low-angle thrusting have been proposed. The style of faulting is important as it is the primary determinant of fracture porosity distribution within the deformed zone. The attitude of a fracture system will, of course, be similar to that of the fault which generated it. Fracture systems associated with high-angle faults can be expected to be oriented at high angles, producing laterally discontinuous fracture distributions. In contrast, low-angle faults are expected to produce fracture systems with low-angle orientations and relatively extensive lateral development. In either case, individual faults and fractured zones within a system may exhibit a vertical or near-vertical orientation and be laterally spaced so as to be indistinguishable with vertically drilled wells.

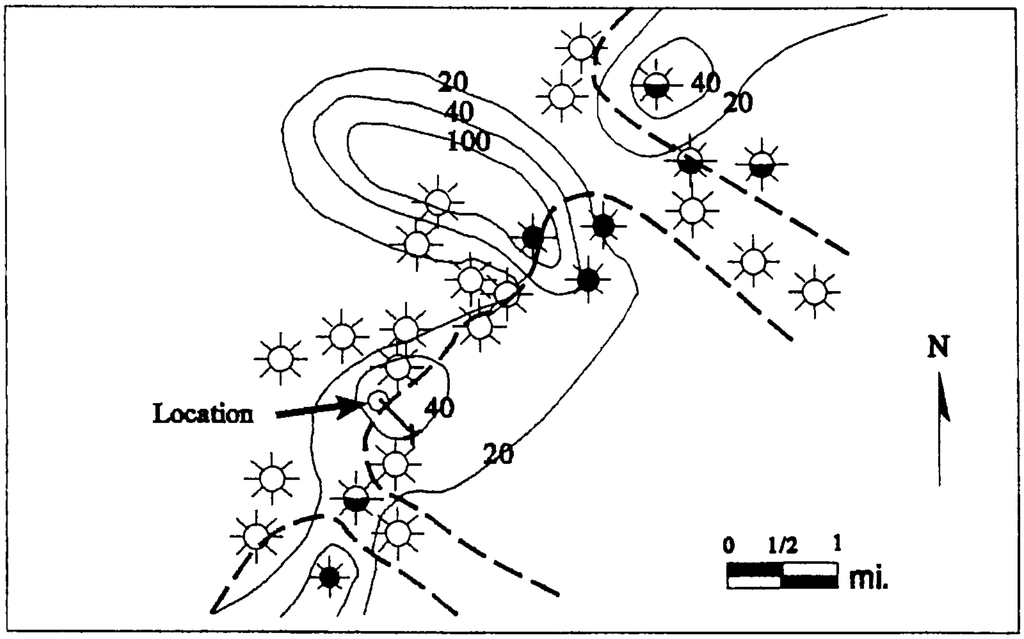


Figure 3. Cumulative 12 mo. production (MMCF) and fault traces on the Lower Huron. After Lowery et al (1988).

II. RESERVOIR MODEL AND WELLBORE SCHEMATIC

A schematic model of the target reservoir and the deviated borehole section are illustrated in cross-section form in Figure 4. Orientation of the borehole and the cross-section azimuth are S48E. The datum is surface elevation (+1004 feet) at the project well site.

Control on the top and bottom of the target zone is from gamma ray log picks at wells 3996, 4003, and 3983 (Tom Ragsdale, personal communication). These data suggest that the target zone top and bottom dip in opposite directions and that the fractured zone thins significantly to the southeast. The base of the target zone dips just over 3 degrees to the northwest, while the top of the target zone dips to the southeast at approximately 8.0 degrees.

The well will be drilled vertically to the "kick-off point" (KOP) at a measured depth of 2000 feet, approximately 50 feet below the base of the Injun sand. From the KOP, the borehole angle is to build continuously at 5.85 degrees per 100 feet of vertical depth, utilizing a bent hole using motor and steering tool, until the targeted 68 degree inclination (with respect to vertical) is reached at a measured depth of 3162 feet (true vertical depth of 2908 feet). The slant portion of the well will be drilled using a rotary hold assembly. Borehole inclination is to be held approximately constant at 68 degrees to a measured depth of approximately 4500 feet (3409 feet true vertical depth) or until the borehole leaves the reservoir zone. Lateral departure is estimated to be 1853 feet (Carden, 1989). Penetration of approximately 800 feet of target zone is expected.

The logging program for the slant portion of the hole will include use of Borehole Television with Gyroscope, Spectral Gamma Ray, Litho-Density, Sidewall Neutron, Dual Induction, and Temperature logs.

No coring is planned at this time. Conventional logging techniques will be attempted initially. However, drill pipe or coil tubing-conveyed equipment will be on site should the gravity-feed approach prove insufficient.

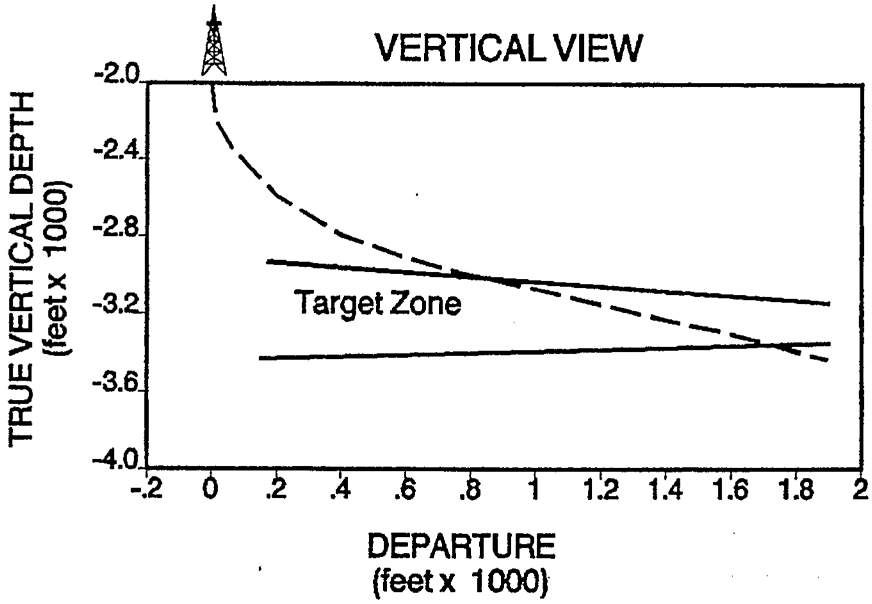


Figure 4. Wellbore - reservoir schematic.

Three or more intervals within the target zone will be completed. Completions will be executed using conventional wireline and tubing equipment. Stimulations of individual zones will be performed as required. A string of 5.5-inch casing will be set at total depth. The casing will either be cemented in place conventionally or productive zones will be isolated with a combination of external casing packers (ECPs) and cemented intervals. Zones with high initial potential (IP) will be completed using ECPs to prevent cement invasion. Lower-IP zones will be completed by cementing across the interval and perforating. Breakdown treatments will be closely monitored and pressure transient testing will be conducted to ascertain formation characteristics for use in frac job design.

Stimulation treatments will be similar to those used on nearby wells and will be limited in the amount of water or liquid used. The deepest zone will be stimulated first and stimulation treatments will continue uphole. Each treatment will be monitored to ensure quality control and to provide accurate documentation (Carden, 1989).

Penetration of multiple, evenly spaced, fracture sets in excess of the three predicted by well control would be considered strong evidence in support of the low-angle fault model for local structural style. This would have two very important implications. First, the existence of multiple, closely-spaced fracture sets would imply that an increase in ultimate recovery sufficiently large to make the project well an economic success is probable. Second, such strong evidence of low-angle faulting in the study area would suggest a high probability that other areas highly favorable for development of the Devonian Shale via directional drilling may exist within the Appalachian basin.

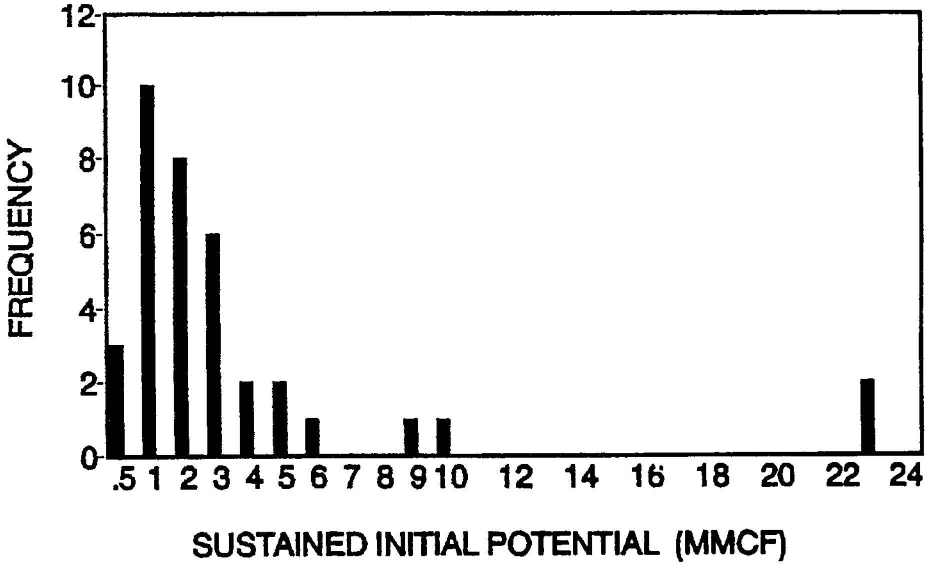


Figure 5. Histogram of sustained initial potential.

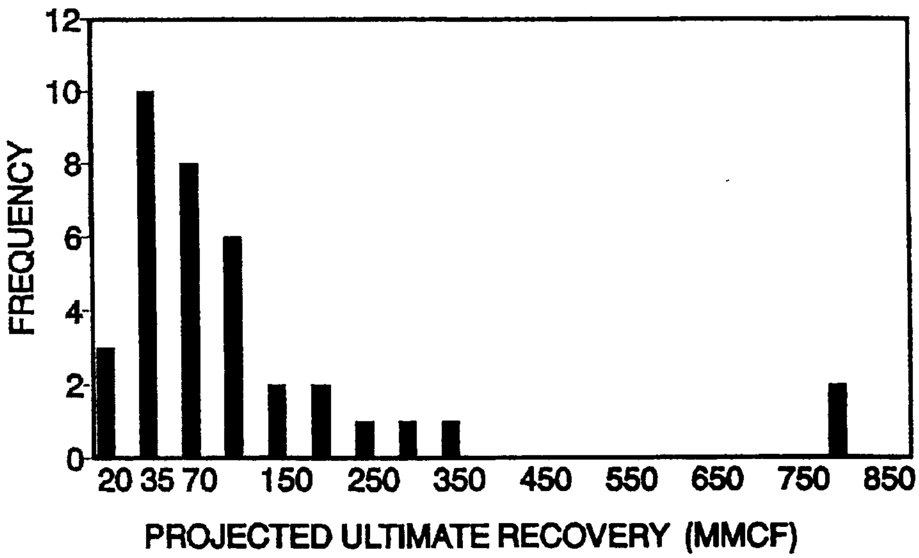


Figure 6. Histogram of projected ultimate recovery in study area.

III. ECONOMICS

Production histories for thirty six wells surrounding the proposed wellsite have been statistically analyzed. State permit numbers for the wells are listed in Table 1. IPs for the thirty six wells are shown in Figure 5. Analysis of sustained IP rates has shown that IPs are approximately log-normally distributed. Log-normality was, therefore, assumed in the analysis. The calculated mean of the distribution is 1.72 MMCF (million standard cubic feet). Mean value plus and minus one standard deviation are 5.02 and 0.59 MMCF respectively. A similar analysis of machine-fitted decline curves suggests that production can be expected to decline hyperbolically. The hyperbolic decline factor is approximately 1.7.

Results of the economic modeling are intended to give a "broad-brush" view of feasible economic results from the alternative investments. Absolute results will, of course, vary with changes in assumptions. For example, significant variation in ultimately recoverable reserves are possible with slight changes in decline assumptions. However, sensitivity analysis has shown that, due to very long project life, calculated NPVs are not very sensitive to such changes. According to the assumptions outlined above, it is concluded that a slant well must achieve slightly more than a three-fold improvement in *expected* ultimately recoverable reserves to match the economic performance of a vertical well.

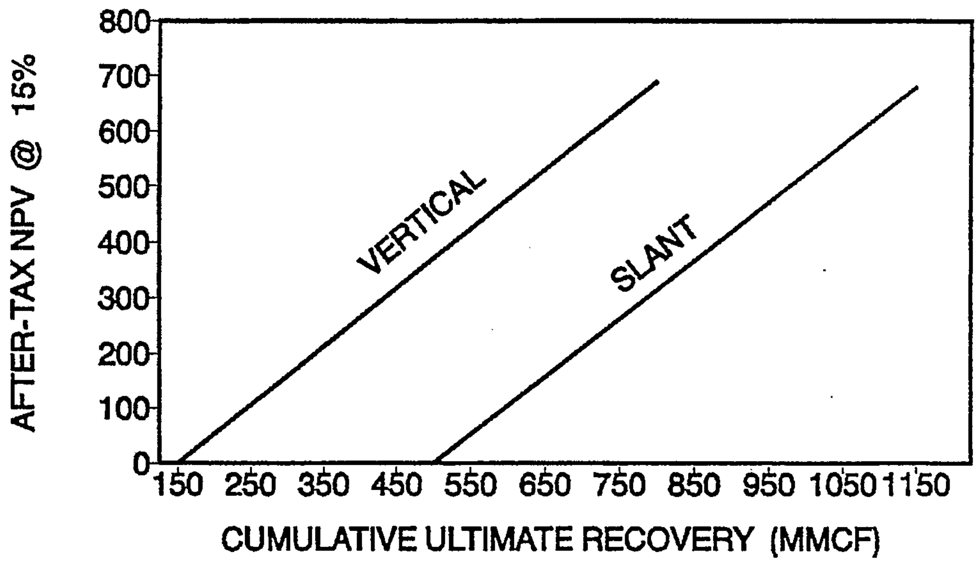


Figure 7. After-tax NPV @ 15% vs. cumulative ultimate recovery (MMCF).

Expected is the key word as it implies consideration of dry hole risk. Certainly the most important advantage to the directional drilling strategy is its ability to reduce dry hole risk. Figure 6 shows that, under our set of assumptions, vertical wells with less than approximately 150 MMCF of reserves will have negative NPVs. Moreover, Figure 5 shows that the probability of this outcome, defined by our sample of thirty six nearby wells is quite high; on the order of 75%!

Since the fracture zone orientation is approximately vertical, the probability of cutting the fractured zone with a borehole is directly proportional to the width of the fractured zone and inversely proportional to fracture zone spacing. The low probability of encountering a well-developed fracture zone with a vertical well is reflected in Figure 6. Figure 6 also shows that when a well-developed fracture zone is hit, reserves can be quite high. In a slant hole, if horizontal departure of the wellbore is very large with respect to fracture zone width and fracture zone spacing, dry hole risk will be enormously decreased and a proportionately increased expected value will be realized. This, combined with the fact that the average cost to drill a slant hole can be expected to decrease significantly as the technology matures, implies that directional drilling has great potential to improve the economics of drilling in the Devonian Shale. By extension, it is concluded that the directional drilling strategy has great potential to increase private industry interest in developing Devonian Shale gas reserves, thus accomplishing the objective of stimulating development of Devonian Shale resources.

IV. SUMMARY AND CONCLUSIONS

This report presents plans and supporting data for the directional well to be drilled under DOE Cooperative Agreement No. DE-FC21-88MC25146. Geological evidence upon which the site selection was based, a reservoir model, drilling, testing and completion plans have been reviewed.

Structural style has been shown to be a key determinant of fracture system geometry and fracture porosity distribution. Insufficient evidence exists to conclusively determine structural style of the study area. Both low-angle thrusting and high-angle reverse faulting have been proposed. The low-angle structural style is felt to be more favorable for development via directional drilling as fracture systems are more likely to exhibit extensive lateral development. Penetration of multiple, evenly spaced, fractured zones in excess of the three predicted by well control will be considered strong evidence in support of the low-angle faulting model. Such strong evidence for low-angle faulting in the study area would suggest a high probability that other areas favorable for development of the Devonian Shale via directional drilling may exist within the Appalachian basin.

A statistical analysis of production data from wells neighboring the proposed location has been presented. The statistical analysis suggests that vertically-drilled wells are subject to very high dry hole risk due to the low probability that the vertically-drilled well will encounter a well-developed fracture zone. Finally, the results of statistically-based economic modeling have been reviewed. Results of the economic modeling strongly suggest that, through a combination of reduced dry hole risk and increased production potential, directional drilling has great potential for improving the economics of drilling in the Devonian Shale. By extension, it is concluded that directional drilling has significant potential for increasing private industry interest in accelerating development of the Devonian Shale gas resource.

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MEASUREMENT-WHILE-DRILLING (MWD) DEVELOPMENT FOR AIR DRILLING

1. CONTRACT NUMBER: DE-AC21-88MC25105

CONTRACTOR: Geoscience Electronics Corporation
725-A Lakefield Road
Westlake Village, CA 91361
(805) 496-0300

PROGRAM MANAGER (CONTRACTOR): William H. Harrison

PRINCIPAL INVESTIGATORS: William H. Harrison

METC PROJECT MANAGER: Albert B. Yost, II

CONTRACT PERIOD OF PERFORMANCE: October 1, 1988 through June 30, 1989

2. SCHEDULE/MILESTONES:

PHASE I Program Schedule (1988-89)

	O	N	D	J	F	M	A	M	J	J
Identification of Wells-of-Opportunity	—									
Analysis and Preliminary Design	—									
Preliminary Design Review (PDR)		△								
Detailed Design		—	—							
Critical Design Review (CDR)			△							
Procurement, Materials and Parts			—	—	—					
Final Assembly, System Integration and Checkout					—	—				
Field MTBF/Tool Reliability Verification Tests							—			
Final Report								—	—	
Phases II/III (Optional)										—

3. OBJECTIVES:

This program is being conducted under cost-sharing contract No. DE-AC21-88MC25105 with the U.S. Department of Energy, Morgantown Energy Technology Center (METC). The program is entitled "MEASUREMENT-WHILE-DRILLING (MWD) DEVELOPMENT FOR AIR DRILLING."

The objective of the program is to tool-harden and make commercially available an existing wireless MWD tool that operates reliably in an air, air-mist, or air-foam environment during Appalachian Basin oil and gas directional drilling operations in conjunction with downhole motors and/or (other) bottom-hole assemblies. The primary application of this technology is high angle and horizontal well drilling in low-pressure, water sensitive, tight gas formations that require air, air-mist, and foam drilling fluids."

The basic approach to accomplishing this objective is to modify GEC's existing "CABLELESS"™ MWD tool to improve its reliability in air drilling by increasing its tolerance to higher vibration and shock levels (hardening). Another important aim of the program is to provide for continuing availability of the resultant tool for use on DOE-sponsored air-drilling programs.

The Contract requires the effort to be accomplished in three phases. Phase I is scheduled to last nine months. The hardened MWD tool must meet the following minimum requirements:

- System MTBF, 50-hours.
- Maximum depth (TVD) of 10,000 feet.
- Battery life in excess of the tool MTBF.
- Operational in rotary drilling and downhole motor scenarios.
- Operate in hole diameters from 6-1/4 to 10-5/8 inch.
- Data transmission rate of 1 bit/second, minimum.
- Operating temperature 135°C, maximum.
- Directional data provided on azimuth, inclination, and tool face.
- Operate in typical air flow rates of 1,500 to 3,000 cubic feet per minute and mist or foam rates from 10 to 30 barrels per hour.

Phase I is aimed at evolving GEC's existing Model 20-C MWD System into a hardened-for-air-drilling MWD tool. The program includes extensive field testing to verify the that the target 50 hour MTBF has been achieved. This evolved hardened tool has been designated the Model 27 MWD.

Specifically, in Phase I, we are embarked on a program to:

- Complete the design of the Model 27 with respect to reliability, shock, vibration, user requirements, and sizes of drillpipe.
- Upgrade two Model 20C MWD systems to Model 27 field operational prototypes.
- Field test the Model 27 tools in air-drilling controlled environments. Evaluate performance and any failures.
- Prepare manuals and a training course.
- Make the Model 27 tools available for optional Phases II and III.

4. BACKGROUND STATEMENT;

In the last few years, the need for reliable, low cost, directional drilling services in air drilling scenarios has become widely recognized. Attempts at using directional drilling systems that were designed to operate in mud have resulted in less than satisfactory performance when operated in air. The severe shock and vibration environment of air operation compared to mud operation immediately extracted a toll in reduced reliability. Mud pulse MWD tools, in general, perform marginally when operated on air and may not be viable. Even though some wireline steering tools have been made to operate reliably in air, the logistics and cost of operating with a wireline are frequently unacceptable.

In 1985, a Model 27 predecessor, the Model 20B "CABLELESS STEERING TOOL"™ successfully underwent extensive field-testing and operational evaluation, primarily high-angle drilling at THUMS, Long Beach. Later, during the Summer and Fall of 1986, the Model 20-B was utilized by DOE Contractor, BDM, on two occasions to evaluate its applicability to air-drilling in the Devonian Shales. This project provided GEC its first experience of the rigors of air drilling. A combination of mechanical failures and computer software problems forced an early withdrawal of the tools .

The primary cause of the mechanical failure was thought to have been the lack of viscous damping and lateral support of the downhole sensor/electronics unit. In ordinary mud drilling, the fairly viscous mud itself provides a modicum of damping to the high-"Q" distributed spring-mass system that is the drillstring and its contents. While the excitation is primarily in the longitudinal axis (and probably no higher than in mud drilling), the damage appears to result from higher-levels of shock and vibration in the transverse axes. The mud appears to provide greater damping in the transverse axes than in the longitudinal axis.

At the conclusion of the tests, GEC undertook a program to improve the tool design by evolving it to the next generation, Model 20-C "CABLELESS STEERING TOOL"™. The Model 20C had significant improvements in the electronics and power units which contributed to improved reliability and operability. Nonetheless, it was recognized that additional hardening and testing was needed to achieve the reliability to meet DOE's air-drilling requirements.

5. PROJECT DESCRIPTION, PHASE I

The following headings sub-divide the project into the major tasks. As the project is now in the latter stages, it seems propitious to describe in Section 6, what has been accomplished, and in Section 7, the work remaining, as follows:

WELLS-OF-OPPORTUNITY.

ANALYSIS AND PRELIMINARY DESIGN.

DETAILED DESIGN AND CRITICAL DESIGN REVIEW.

FABRICATION, ASSEMBLY AND CHECK-OUT.

FIELD MTBF/TOOL RELIABILITY VERIFICATION TESTS.

FINAL REPORT.

6. RESULTS/ACCOMPLISHMENTS, PHASE I:

WELLS-OF-OPPORTUNITY.

Working through our Appalachian Basin Drilling Consultant, a number of operators who were considered to be candidate test partners were contacted. From these interviews, a list of "Wells-of-Opportunity" was created. A "Wells-of-Opportunity" report was prepared and submitted.

ANALYSIS AND PRELIMINARY DESIGN.

The expected air-drilling mechanical stresses were estimated based upon our own experience and that of our consultants. An analysis of the Model 20C mechanical design was conducted in light of the above and its weaknesses were identified. Several preliminary designs were explored in detail to determine the most effective approach to overcome these the deficiencies. The primary focus was upon the Downhole Instrumentation Unit (DIU) pressure barrels and centralizers. The results of this work were reviewed by GEC engineers, GEC consultants, and the COTR at the Preliminary Design Review (PDR) that was conducted at the completion of this task. The approach that was established included the following salient features:

- Nytronics 50 Pressure Barrels to house the Electronics, Sensor and Battery Units with diametrical internal threads extending over one inch in depth (Figure 1).

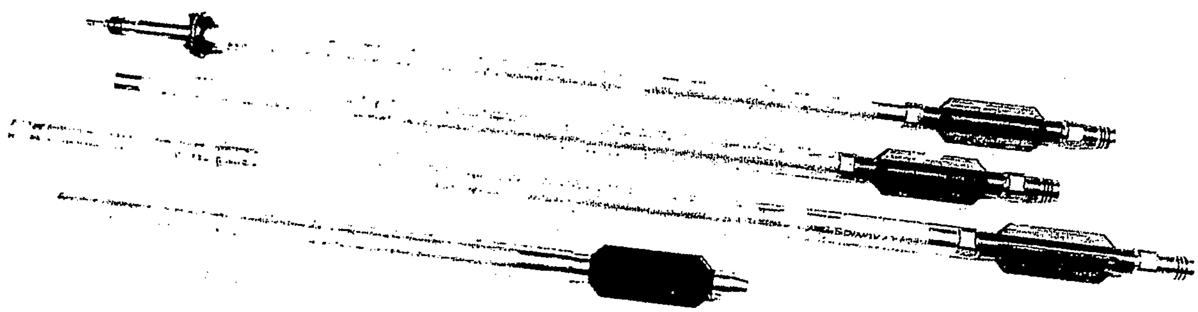

Figure 1. Pressure Barrels.

- Large finned, rubber molded centralizers at close-spaced intervals to support the Downhole Instrumentation Unit (DIU) inside of the survey collar (Figure 2).

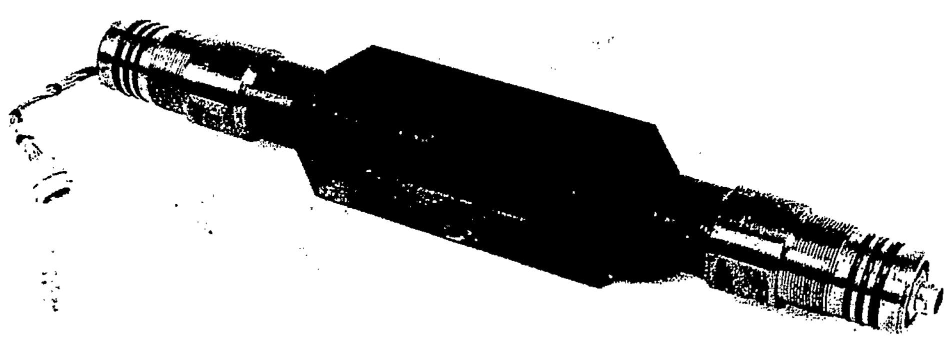

Figure 2. Rubber-Molded Centralizer.

• All pressure interfaces include multiple O-Rings with characteristics to seal against air and liquids over wide pressure ranges (Figure 3).

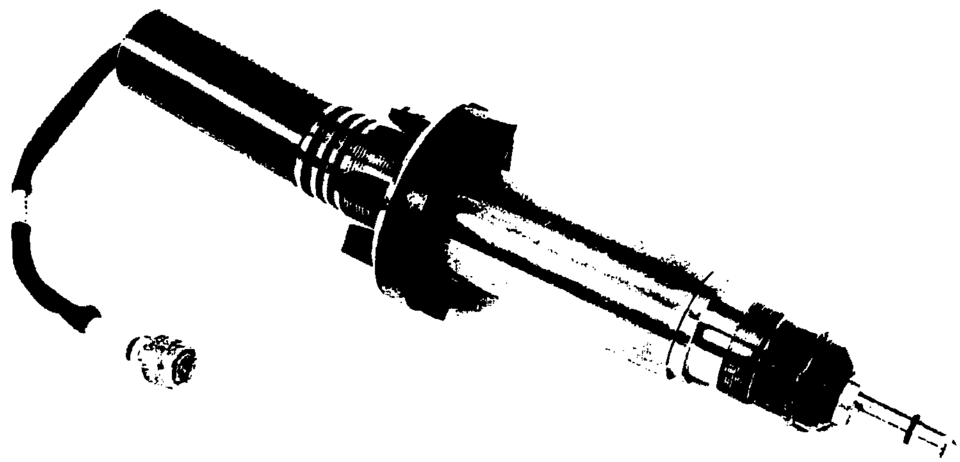

Figure 3. "O" Ring Pressure Barriers.

• Improved internal vibration and shock isolation (Figure 4).

Figure 4. Internal Shock and Vibration Suppression.

- Alternate Sensor Package containing 12 two-axis acceleration switches built to monitor shock environment (six pairs scaled from 20 to 70 g's in 10 g increments)(Figure 5).

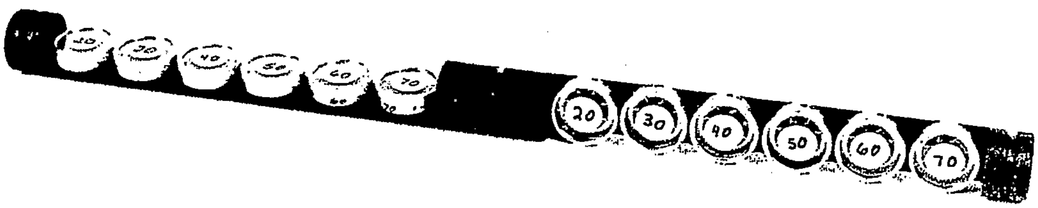

Figure 5. Alternate Sensor Package Using Acceleration Switches.

- Lengthened Flow Deflector with increased window cross sections to minimize choke points (Figure 6).

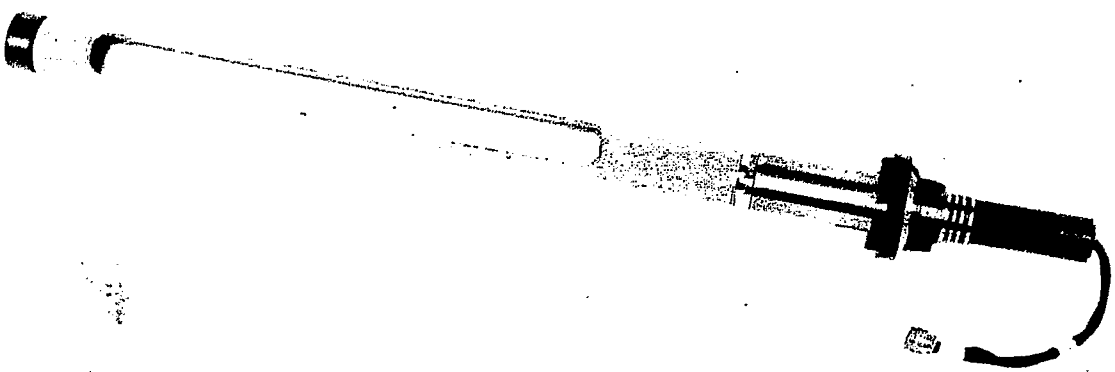

Figure 6. Re-designed Flow Deflector.

* Larger bore (3-1/4" I.D.) survey collar to reduce air velocity around the tool.

DETAILED DESIGN AND CRITICAL DESIGN REVIEW.

The detailed design, and fabrication drawings of new piece-parts and subassemblies were executed. Certain long-lead materials and parts were ordered. A Critical Design Review (CDR) was conducted in December 1988.

FABRICATION, ASSEMBLY AND CHECK-OUT.

Procurement of all of the new parts was initiated. Final assembly was performed as part became available. All of the Model 20C assemblies and subsystems that are being used unchanged were calibrated and checked-out. The various computer programs that were known to require modification to be compatible with the air drilling scenarios were updated and debugged. Both the Downhole and the Uphole Subsystems were assembled and operated in field deployed configuration to verify functional compatibility.

7. FUTURE PLANS

PHASE I -- WORK REMAINING.

Field MTBF/Tool Reliability Verification Test.

This task will primarily involve field operations in the Appalachian Basin, in directionally drilled using downhole motors. The important aspect here is to gain as much data as possible about the reliability of the Model 27 tools under a variety of air-drilling scenarios. A final list of wells-of-opportunity will be prepared and several wells will be chosen that best fit the desired test parameters, including logistics and schedule constraints. It is anticipated that these tests will take place over a three-week period.

Final Report.

This task covers preparation of the Final Report in conformance with the Contractual requirements, and a Tool-User's Manual for use in training new operators.

PHASE II and III-- TOOL UTILIZATION IN A DESIGNATED WELL OF OPPORTUNITY (OPTIONAL)

Well Plan.

DOE will locate and arrange for a well of opportunity. GEC will then, utilizing its Appalachian consultant, prepare a Well Plan for approval by the COTR.

Tool Utilization at a Well of Opportunity.

GEC will make available, through its Appalachian licensees, Model 27 Systems and operational support. GEC will provide Daily Drilling Reports to the COTR with all MWD data acquired during well drilling operations.

The Model 27 will be run long enough to establish good MTBF data. Following the work, GEC will provide a topical well report that will include an analysis of the reliability of each tool tested as a function of the operating conditions experienced.

Phases II and III will require about four months each. Phase II is estimated to start in late 1989 and Phase III in early 1990.

GEC ONGOING PROGRAM.

Geoscience Electronics Corporation intends to continue its ongoing program of Electromagnetic Borehole Communications System (EBCS) development, and to complete its internally-sponsored project for the Model 27 MWD system for unconventional resource drilling (drain-holes, air-drilling, slant-horizontal and others). However, it should be noted that GEC does not presently recognize a sufficiently large market in air-drilling to unilaterally accomplish DOE's larger goals, and therefore welcomes DOE's interest and support.

This program is expected to contribute materially to making available highly productive, cost effective directional drilling services to the slant-horizontal, air-drilling community, and others requiring similar tools, especially for use in the Devonian Shales.

MULTIPLE ZONE COMPLETION OPPORTUNITIES

1. CONTRACT NUMBER: DE-AC21-86MC23140

   CONTRACTOR: Columbia Gas System Service Corporation
   Supply Research
   1600 Dublin Road
   Columbus, OH 43215
   (614) 481-1495

   CONTRACTOR PROJECT MANAGER: Gregory Koziar

   PRINCIPAL INVESTIGATOR: Gregory Koziar

   METC PROJECT MANAGER: Charles W. Byrer

   PERIOD OF PERFORMANCE: July 19, 1986 Through June 16, 1989

2. SCHEDULE/MILESTONES:

Phase II Schedule*

```
                                        1988             1989
                              J F M A M J J A S O N D J F M A M J

DATA COLLECTION               +---+
IDENTIFY SAND/SHALE AREAS     +
PARTITION AREAS                                     +-+
TYPE CURVE DEVELOPMENT                    +-----------+
MAPS                                +-----------------+
DEFINE PLAYS                                +---+
ECONOMIC ANALYSIS                                             +---+
ANALYSIS/CONCLUSIONS          +---------------------------------+
REPORTING                     +---------------------------------+
```

*Phase 1 contained similar tasks.

3. OBJECTIVES:

The primary goal of this project is to increase exploitation and development of Devonian shale gas reserves outside historically productive shale regions within the Appalachian basin. To accomplish this goal, a project was structured to identify Devonian shale gas potential and demonstrate to producers the economic viability of that potential in those nonhistoric areas. The primary project objectives consist of:

- Identifying areas of favorable Devonian shale gas potential.
- Partitioning and ranking each area on the basis of expected reservoir quality and production potential.
- Demonstrating the economic benefits of including the Devonian shale as a secondary completion target.

4. BACKGROUND:

Research sponsored through USDOE's Eastern Gas Shale Program and GRI's Devonian Shale Exploration and Production Studies has resulted in significant contributions towards understanding the Devonian shale. Geological, reservoir, and producing characterization have occurred as a result of developments in coring, geophysical well log interpretation, well test analysis, hydraulic fracturing stimulation, and mathematical modeling. Research efforts sponsored by USDOE and GRI have expanded and continue to expand our knowledge of mechanisms controlling production and recovery efficiency. Unfortunately, this effort has provided little in the way of industry development of new Devonian shale gas reserves beyond historically productive regions.

The economic climate in recent history has contributed little to encourage Devonian shale gas exploitation: development remains at a minimum in most historical areas and is virtually nonexistent elsewhere in the basin. Outside historical shale areas, economics are typically marginal or worse for wells specifically targeting the Devonian shale.

But, in many parts of the basin potentially productive formations co-exist, some of which produce gas concurrently. Many horizons produce in geographical localities outside historical Devonian shale production but in areas which demonstrate Devonian shale gas potential. In addition, many producers are actively drilling nonshale horizons within these potentially productive Devonian shale areas. These wells provide an excellent opportunity to exploit potential Devonian shale gas reserves as a secondary or dual completion interval at a minimal incremental cost.

The key to increasing Devonian shale gas interest, development, and hence gas reserves in nonhistoric shale areas is through producer awareness of shale gas potential in his area of activity. To stimulate interest in Devonian shale gas development, the approach adopted in this research study is to demonstrate shale gas potential and the economic viability of exploiting that potential in areas where nonshale formations are primary targets.

While this study does identify various nonshale producing formations and establishes generic production profiles for several of the horizons, the primary thrust is to demonstrate Devonian shale potential and to promote its exploitation. The use of Devonian shale gas as a supplement to production (and well economics) in areas of nonshale drilling activity is the means of achieving this end.

5. PROJECT DESCRIPTION:

This project consists of two phases. Phase I concentrated on developing the methodology to extrapolate historic areas of concurrent shale/nonshale production into nonhistoric shale areas[1]. Phase II extended the Phase I work beyond the periphery of historic Devonian shale production.[2] Phase I tasks were limited in scope and restricted to certain regions of Jackson and Kanawha counties, West Virginia. That area contained core acreage where considerable knowledge and data were available for both the Devonian shale and other producing horizons.

Both phases contained identical tasks which include:

- Collection and Tabulation of Geological, Reservoir, and Production Data.
- Identification of Currently Active Drilling Areas.
- Identification of Areas of Sand/Shale Potential.
- Development of Production Type Curves.
- Construction of Maps and Cross-Sections.
- Identification of Potential Shale/Sand Play Areas.
- Comparative Economic Analysis.
- Data Analysis and Conclusions.
- Reporting.

To achieve the overall objective, the project was structured to partition or break up the study area into segments containing distinct geologic, reservoir and production characteristics. Each partition would then be ranked according to production potential, economics, and risk. During Phase II, emphasis was placed on attempting to establish more favorable reservoir locales by identifying trends and correlations among various parameters.

6. RESULTS/ACCOMPLISHMENTS:

DEVONIAN SHALE PRODUCTION POTENTIAL INDICATORS

To aid in defining more favorable areas of Devonian shale production potential, many parameters were studied for trend identification: initial open flow (IOF), cumulative production(Q), permeability-thickness (kh) product, modified productivity index (J_m), normalized (to kh) modified productivity index and stress ratio (SR) values.

Regression analyses were performed in an attempt to establish simplified relationships among the various parameters evaluated, and to elucidate the significance of each variable as an indicator of Devonian shale production potential.

Stress Ratio

Regression analyses of stress ratio with regard to IOF, J_m, J_m/kh, and cumulative production demonstrated no direct correlation. Stress ratio values were then grouped in intervals of 0.05, averaged and plotted against the average value of the "y" variable in an attempt to identify any modal behavior. That is, determine whether any stress ratio intervals exhibit a dominant behavior.

Cumulative production through the first year, Figure 1, shows distinctly higher productivity for stress ratio values ranging between 0.4 and 0.5. A similar profile is noted for cumulative production through the third year. This correlation suggests that Devonian shale production potential is greatest within this stress ratio range and should be targeted accordingly.

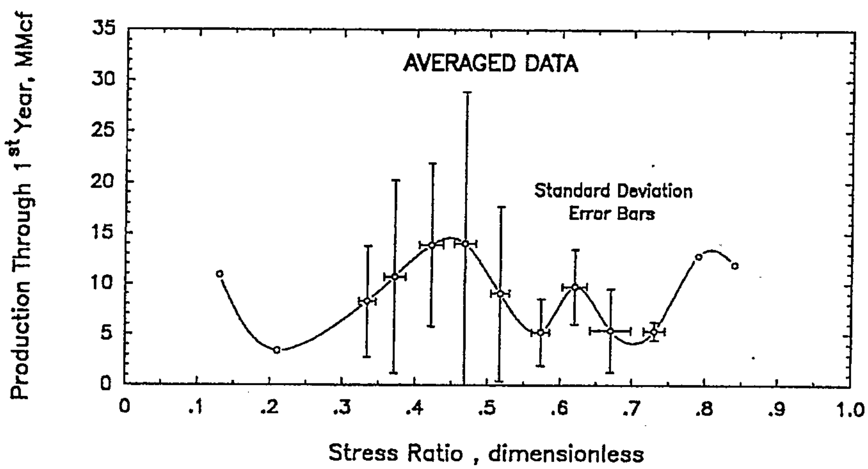

Figure 1. — First year cumulative production as a function of stress ratio.

Both the kh-stress ratio and J_m-stress ratio curves follow a profile similar to that of cumulative production-stress ratio in approximately the same stress ratio range. The highest kh and J_m values occur in the stress ratios range of about 0.35 - 0.50; an additional peak occurs at 0.60 - 0.65.

Based upon the previous observations, it is concluded that areas with low stress ratio values, ranging from about 0.35 to 0.60, are more likely to contain favorable reservoir conditions and, consequently, higher Devonian shale production potential. It is cautioned that wells completed within areas of this stress ratio range still contain poor producers. However, the probability of encountering a better producer is greater here.

Permeability-Thickness Product

Regression analyses were attempted between kh and IOF, cumulative production, and J_m. IOF versus kh produced a shotgun scatter with no correlation.

A linear regression was performed on kh vs cumulative production through the first and fifth years. While a general trend appeared, the standard deviation for each correlation was quite large.

A plot of kh versus J_m, Figure 2, produced the best linear relationship. Several high kh values with associated low J_m values tend to skew the

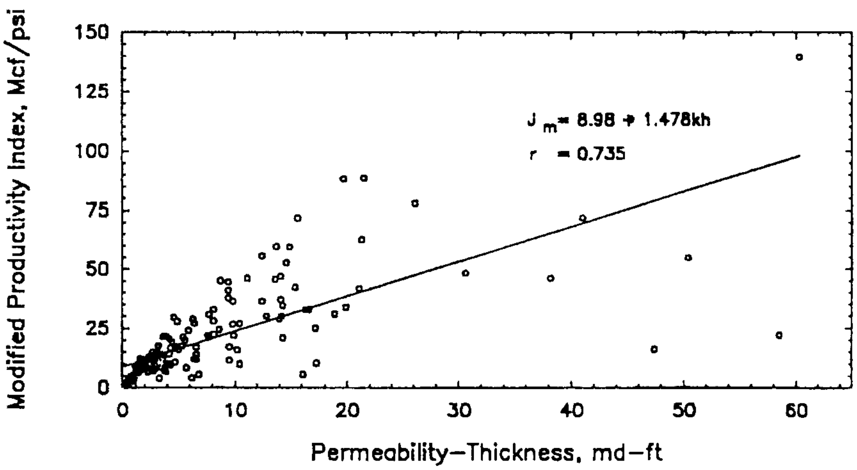

Figure 2. — Correlation between modified productivity index and kh.

regression line in favor of these anomolous points. Nonetheless, a fairly high correlation exists. The significance of this relationship is that an estimate of the first year's production could be calculated from an approximation of kh (which can be easily obtained from a single-point well test[3] and the initial reservoir and flowing well pressures).

Very strong correlations exist between cumulative production through the first year and both cumulative production through the third and fifth years. Figure 3 shows the correlation for the former. Once Q_1 has been determined from the modified productivity index equation[2], it can be substituted into the appropriate regression equations to determine cumulative production through the third and fifth years.

PARTITIONED AREAS OF FAVORABLE DEVONIAN SHALE POTENTIAL

Figure 4 identifies three areas deemed as having favorable Devonian shale potential. Favorable potential is loosely defined as having a good chance of encountering Devonian shale production of at least medium rate.

Areas I, II and III were determined from contour projections of first year cumulative production, modified productivity index and kh values.

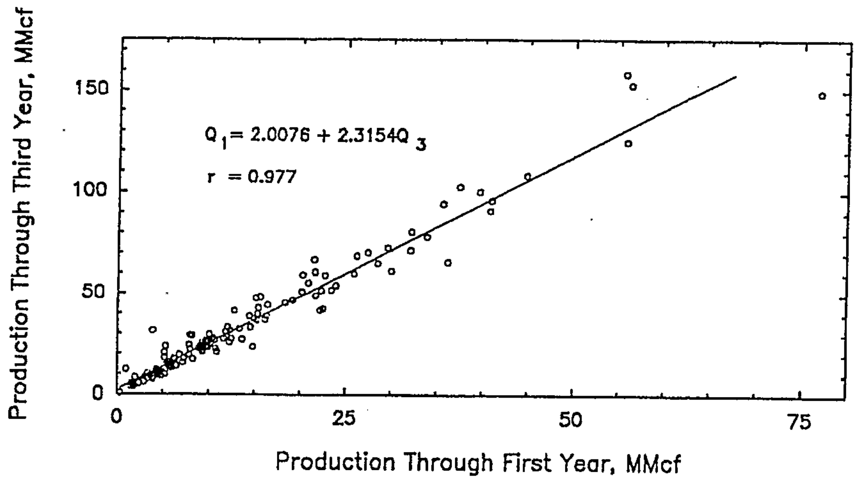

Figure 3. — Cumulative production correlation.

The three contour maps were superposed. Criteria for establishing these areas were minimum values of 20 MMcf for the first year production, 20 md-ft for kh and 50 Mcf/psi for J_m.

Portions of each area include data points or contour levels which do not meet all three criteria. For example, southern portions of Area I contain wells with cumulative production meeting the 20 MMcf requirement while kh or J_m do not meet minimum requirements.

Also, data are transitional and vary widely from location to location. Good producers are interspersed with poor producers. Consequently, each area grossly represents confines within which exists a higher probability of encountering favorable shale gas production.

Based on the 165 randomly selected wells in the study region, about 20 percent are considered medium volume (20 MMcf/first year) or better producers. The average first year production for all 165 shale producers is 13.5 MMcf. In contrast, 50 percent of the 42 wells contained within Areas I, II and III are considered medium volume or better producers. The collective average first year production for Areas I, II and III is 20.1 MMcf - nearly 49 percent greater than the area as a whole.

Table 1 summarizes values for Q1, Q3, kh, J_m, J_m/kh and SR for each partitioned area. Averaged values are also shown for all three partitions as well as averaged values for the entire study area.

The data in the table suggest that a well completed within a partitioned area can be expected to have significantly better production than that from a well randomly drilled within the study area. It is noted that sample size of Areas II and III are small, 11 and 6 wells respectively. Although well selection was entirely random, the small population of wells within these two areas may not be as good a statistical indicator of expected performance as that of Area III which contains 25 wells.

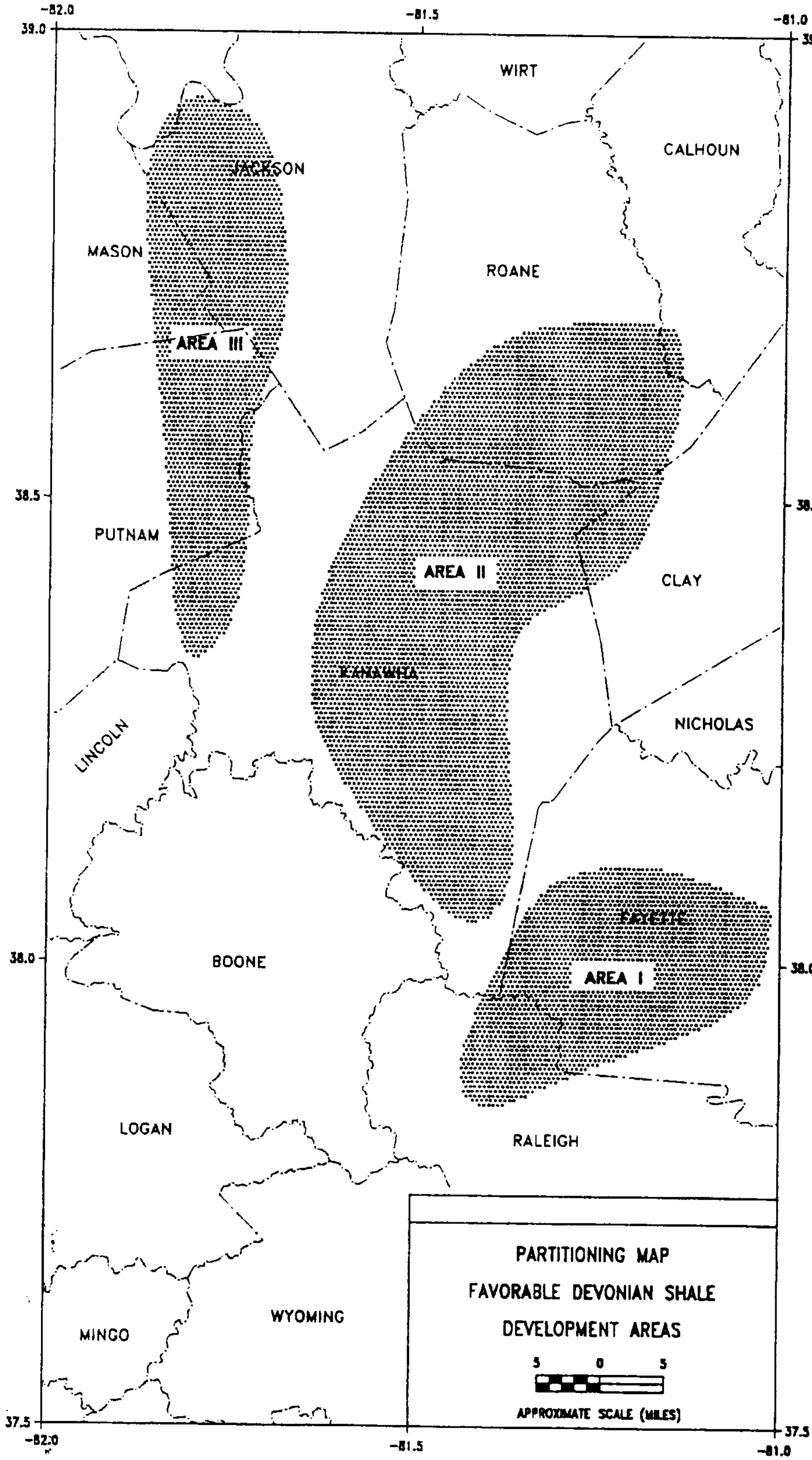

Figure 4. - Partitioning map of favorable Devonian shale development areas.

Table 1. Summary of Partitioned Area Properties.

	Partitioned Area			Averaged Values For:	
	I	II	III	Partitioned Areas	Study Region
Q_1	18.3	24.6	19.7	20.1	13.5
Q_3	41.7	63.8	43.8	47.3	34.2
kh	10.7	16.0	13.7	12.6	8.1
J_m	25.7	42.4	43.9	36.7	21.0
J_m/kh	3.8	3.4	3.4	3.6	3.7
SR	0.49	0.50	0.49	0.49	0.50

Figure 5 shows average production curves for partitioned Area II. Three curves representing high, medium and low producers are shown.

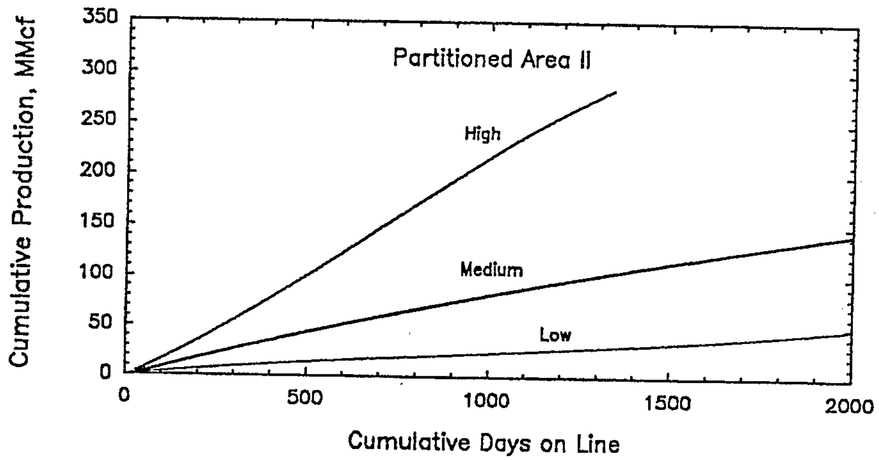

Figure 5. – Devonian shale production curves for partitioned area II.

Improved parametric relationships also exist within the partitioned areas as compared to the overall study area. For example, a relationship between J_m and kh shows a correlation coefficient improvement from 0.74 to 0.83 when using data contained within the three partitioned areas.

Production performance and parametric correlations within Partitioned Areas I, II and III are statistically better than that for the study area as a whole. Supplementing well production with gas from the Devonian shale, especially from the partitioned areas, will be shown in an Economic Analyses topical report to have greater economic benefit to the operator while simultaneously permitting exploitation of Devonian shale gas beyond historical limits.

RANKING OF PARTITIONED AREAS

The Partitioned Areas clearly demonstrate a greater Devonian shale production potential as compared to the study region as a whole. Data in Table 1 also suggest that significant differences exist among the partitions. Area II displays the highest production potential whereas Areas I and III appear quite similar from a productivity standpoint. This suggests that Area II should be the primary target for developing nonhistoric Devonian shale gas potential.

It is cautioned that partitioned Area II covers a large areal extent and that only 11 wells having three years' production are represented here. As was previously noted, this small population of wells may not be indicative of expected production performance. Additional support for partitioned Area II can be found in the fracture spacing information developed by Kuuskraa[4] et al. Table 2 is a modification of that data conforming to the Multizone Study partitions.

Table 2. Average Geologic Properties.

Multizone Partitioned Area	Fracture Spacing (Feet)	Permeability Anisotropy (Ratio)
I	10 - 15	2:1 to 4:1
II	15	4:1
III	30	8:1

Partitioned Area II shows an average fracture spacing of 15 feet which compares favorably with Area I and is much better than Area III. While natural fracturing certainly enhances productivity, it is not the only means of permeability enhancement. Proceeding eastward across the study area, facies changes occur. Silty shale interfingered with organically rich shale is believed to provide higher permeability channels for improved productivity.

7. FUTURE WORK:

The remaining work to be performed consists of an Economic Analysis topical report. Single zone completion economics of the Devonian shale, Big Lime and Oriskany will be compared to that of dual completions of the Big Lime and Oriskany each with Devonian shale. Recompletions will also be considered in existing nonshale wells, for example, plug back from the Oriskany and deepening from the Big Lime to the Devonian shale. This analysis will be performed over the general study area and each of the three partitioned areas.

8.0 REFERENCES:

1. Koziar, G., Columbia Gas System Service Corp., "Multizone Completion Opportunities in the Appalachian Basin" Phase I, Final Report, USDOE Contract No. DE-AC21-86MC23140, September 16, 1987.

2. Koziar, G., Columbia Gas System Service Corp., "Multizone Completion Opportunities in the Appalachian Basin," Final Report, USDOE Contract No. DE-AC21-86MC23140, March 31, 1989.

3. Lee, W. J., Kuo, T. B., Holditch, S. A., and McVay, D. A., "Estimating Formation Permeability From Single-Point Flow Data," SPE/DOE/GRI 12847, Unconventional Gas Recovery Symposium, Pittsburgh, PA, May 13-15, 1984.

4. Kuuskraa, V. A.; Wicks, D. E.; Lewin and Associates, Inc. and Consultants, "Technically Recoverable Devonian Shale Gas in West Virginia." USDOE Contract No. DE-AC21-82MC19239, December 1984.

9. NUMENCLATURE:

Symbol/Term	Meaning
h	Net pay, ft.
IOF	Initial Open Flow
k	Permeability, md.
kh	Permeability Thickness Product, md.-ft.
J_m	Modified Productivity Index = $Q_1/P_i-P_{wf})$
Q_1	First Year Production, MMcf
Q_3	Three Years' Production, MMcf
P_i	Initial Reservoir Pressure, psi
P_{wf}	Average Flowing Pressure (First Year), psi
SR	Stress Ratio = Ratio of the minimum horizontal stress to the vertical stress

HORIZONTAL WELL PROSPECTUS
A PROCEDURE FOR RELATIVE RANKING OF SITES SELECTED FOR HORIZONTAL WELLS IN TIGHT, NATURALLY-FRACTURED RESERVOIRS

1. CONTRACT NUMBER: 9-896/RK-12, METC - EASTERN GAS SHALES SYSTEMS ANALYSIS

CONTRACTOR: U.S. DOE, Systems and Technology Support Division
P.O. Box 880
Morgantown, West Virginia 26507-0880
304-291-4641

PRINCIPAL INVESTIGATOR: Anthony M. Zammerilli

METC PROJECT MANAGER: Albert B. Yost

CONTRACT PERIOD OF PERFORMANCE: October 1, 1988, through September 30, 1989

2. ABSTRACT:

The relative merits of locating horizontal wells in a naturally-fractured shale gas basin are examined in light of controllable and non-controllable factors. This methodology examines non-controllable variables (such as existing reservoir pressure, payzone thickness, and success ratios) as well as controllable variables (such as gas price and drilling costs) to arrive at the profitability for a horizontal well project in a candidate area. An analysis of the expected monetary value (EMV) and a cash flow model are used to obtain a distribution of cash flow levels, yielding a determination whether or not a project is likely to be an economic success. Ranges of profitability for an unstimulated horizontal well are graphically presented. Using this approach, the most likely areas where horizontal drilling can be an economical and technical success are easily and quickly identified.

3. BACKGROUND STATEMENT:

The tight, naturally-fractured Devonian shales of the Appalachian Basin serve as the project area for this horizontal well ranking study. The State of West Virginia had previously been partitioned into three geologic settings, reflecting the types of Devonian shales present. Figure 1 shows the primary partitioned areas in Geologic Setting I, an organically rich, black shale region (Huron-Rhinestreet Formation), the area that is the focus of this study. Geologic Setting I is partitioned into six areas based on the geologic data that establish the natural stress and natural fracture distribution of these Devonian shales. These partitions were validated with 40 years of cumulative gas production data (Lewin 1984). Table 1 lists the counties included in each of the six partitions.

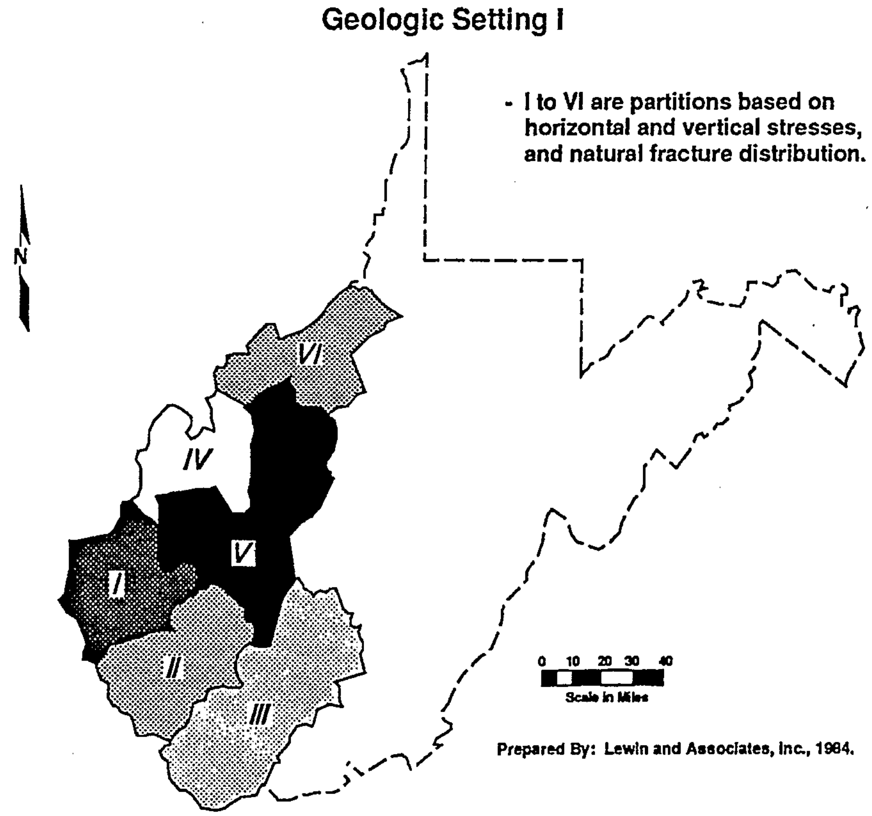

Figure 1. Primary Partitioned Areas of Devonian Gas Shales in West Virginia

Reservoir parameters for each of the partitions were used in a finite difference, dual porosity, single phase reservoir simulator to predict horizontal well gas production over a 10-year period. Predicted productions were then used in a cash flow model to determine economic parameters at different gas price scenarios. EMV calculations were completed using Devonian shale success ratios compiled by the West Virginia Geological and Economic Survey for DOE. (See Table 2.)

EMV analysis was completed at each gas price level for all of the partitions. Each horizontal well project was then ranked on the basis of its respective EMV value, with the sites showing the highest EMVs considered as the best candidate areas for development.

Expected monetary value of an outcome is obtained by multiplying the probability of the occurrence of the outcome (success reward or failure cost) and the conditional value or worth that is received if the outcome occurs (Newendorp 1975). Accordingly, EMV is defined as Expected Monetary Value = (Reward x Probability of Success) - (Cost of Failure x Probability of Failure). Reward values can be expressed in terms of monetary profits on a before- or after-tax basis. These monetary values may be undiscounted values or discounted net present value (NPV) profits.

Table 1. Partition County Listing

Partition	Counties
I	Cabell Wayne Lincoln
II	Mingo Logan Boone
III	Fayette Raleigh Wyoming McDowell
IV	Mason Jackson
V	Calhoun Roane Putnam Wirt Kanawha
VI	Wood Pleasants Tyler Ritchie

The most common practice is to examine calculated EMVs, based on after-tax analysis with discounted NPV profits. However, this study focuses on before-tax cumulative cash flow as the reward values, and dry hole costs as the cost of failure values. This is done so that the actual revenue generated from one area can be compared easily and simply with other areas. For example, if a well project generates $500,000 as a before-tax cumulative cash-flow, and the dry hole cost (capital investment) is $200,000, the EMV for the project using a 80 percent success ratio would be

$$EMV = (\$500,000 \times 0.80) - (\$200,000 \times 0.20) = \$360,000.$$

Table 2. Devonian Shale Success Percentages (%)

Partition Area	County	1980	1981	1982	1983	1984	1985	1986	1987	20 Year Totals: Number of Devonian Gas Wells	20 Year Totals: Expressed As % Success
I	Cabell	100.00	100.00	100.00	100.00	100.00	85.71	100.00	ND	132	97.06
I	Wayne	100.00	90.91	95.24	100.00	100.00	66.67	100.00	100.00	102	95.33
I	Lincoln	100.00	100.00	75.00	100.00	100.00	50.00	33.33	66.67	78	84.78
II	Mingo	87.50	95.24	100.00	100.00	100.00	50.00	ND	ND	129	94.85
II	Logan	ND	50.00	100.00	100.00	100.00	100.00	100.00	ND	16	88.39
II	Boone	100.00	100.00	100.00	87.50	100.00	100.00	ND	100.00	60	95.24
III	Fayette	85.71	66.67	90.00	66.67	100.00	100.00	100.00	ND	38	88.37
III	Raleigh	100.00	100.00	50.00	100.00	50.00	100.00	100.00	100.00	39	95.12
III	Wyoming	ND	25.00	100.00	ND	100.00	100.00	100.00	100.00	14	77.78
III	McDowell	ND	100.00	100.00	75.00	100.00	75.00	ND	100.00	21	87.50
IV	Mason	70.00	88.24	100.00	100.00	100.00	100.00	ND	ND	124	93.94
IV	Jackson	100.00	94.00	96.39	92.50	96.88	100.00	100.00	100.00	362	96.53
V	Calhoun	100.00	50.00	100.00	97.78	97.44	100.00	100.00	100.00	230	92.37
V	Roane	ND	91.30	100.00	100.00	95.12	94.29	100.00	100.00	200	95.69
V	Putnam	100.00	100.00	93.75	100.00	100.00	100.00	100.00	100.00	209	99.05
V	Wirt	100.00	100.00	96.67	98.31	93.33	96.30	80.00	100.00	218	94.37
V	Kanawha	92.00	100.00	100.00	93.75	100.00	99.04	97.78	98.77	538	98.18
VI	Wood	51.65	71.79	72.00	70.00	100.00	87.50	100.00	100.00	156	65.27
VI	Pleasants	86.11	84.69	98.99	89.52	82.52	76.92	100.00	0.00	635	86.51
VI	Tyler	62.86	74.19	73.33	100.00	100.00	92.86	83.33	100.00	178	83.18
VI	Ritchie	90.12	90.80	94.32	96.65	93.80	97.35	94.83	100.00	1,426	93.75
TOTAL		82.81	89.43	94.69	95.99	95.37	95.15	96.53	98.46	4,905	90.7

* Compiled by West Virginia Geological and Economic Survey.
ND = No data.

4. PROJECT DESCRIPTION:

A flow chart summarizing the steps in this study is shown in Figure 2.

The first step in completing this study was to obtain reservoir data for the partitions, along with the current gas price and drilling cost data for horizontal drilling in Devonian shales. Actual costs from an ongoing DOE horizontal well project served as the basis for the cost data, revised to reflect normally incurred costs rather than higher research drilling costs (Yost 1987). In addition to these data, a 2,000-well database for the Devonian shales was also available. This database along with well records from other sources provided the historical production data and reservoir properties needed to history match and characterize each partition. Unique reservoir data, such as pay zone thickness, fracture and matrix permeability, and initial pressure (from shut-in data), were then used to predict the 10-year cumulative gas production from a 2,000-ft (6.1×10^2 m) horizontal well draining 80 acres (3.2×10^5 m^2) in a new lease area. Table 3 lists the basic reservoir parameters and average success ratio data used for each partition.

Infill drilling was not addressed since previous studies have shown new lease horizontal drilling to be economically more attractive than infill drilling (Zammerilli 1989).

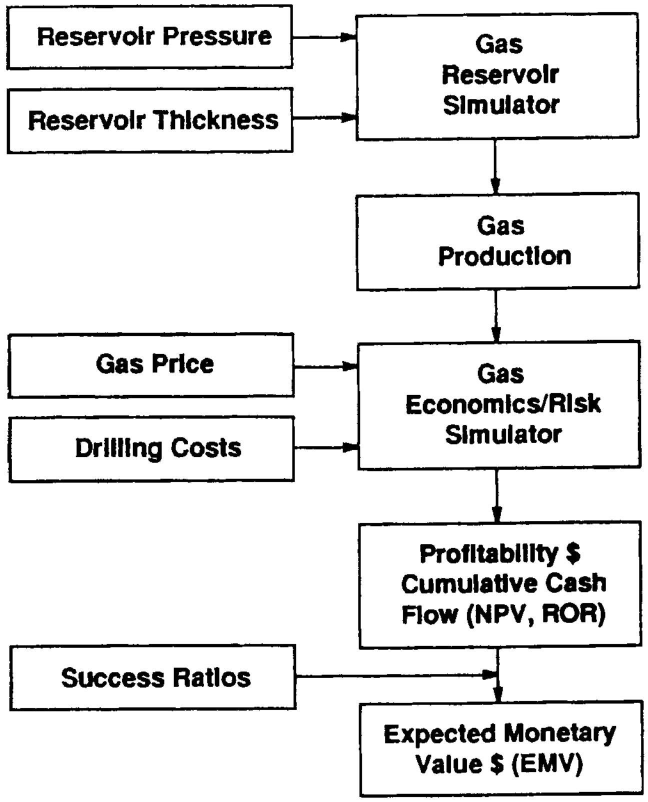

Figure 2. Flow Diagram for EMV Determination

The next step was to complete an economic/EMV-risk analysis on each partition, using the predicted annual gas production as input data. A truncated normal distribution was used for gas price to reflect the minimum, maximum, and most likely initial gas price. (See Figure 3.) The most likely initial gas price of $2.16 reflects recent wellhead gas prices in West Virginia. Escalation of the initial gas price at an annual 4 percent was used to account for inflation. Drilling costs of approximately $848,000 reflect data from a previous report examining a horizontal drilling case study in Devonian Shale.[3]

A personal computer (PC)-based cash-flow model was then run to obtain the most likely before-tax cumulative cash flow at the end of a 10-year horizontal well project for each area. This was repeated for initial gas prices of $1.50, $2.16, $2.50 and $3.00/Mcf ($42.48, $61.17, $70.80, and $84.96/m^3). Along with cumulative cash flow, payback and rate of return were also determined.

Where does risk enter into this analysis? Risk is synonymous with uncertainty, and uncertainty is quantified or addressed through the use of probabilities. Uncertainty is introduced in the next step with the use of success ratios in the EMV calculation for each gas price level in the

Table 3. Partition Area Reservoir and Economic Data

	Non-Controllable Factors				Controllable Factors	
Partition	Permeability (md) and Anisotropy (kx:ky)*	Success Ratio (%)	Thickness (ft)	Pressure (psi)	Gas Price ($/Mcf)	Drilling Costs
I	0.7 1:1	92.4	100	1,000	$1.50 to $3.00	$848,000
II	0.07 1:1	93	100	1,000	**	$848,000
III	0.02 8:1	87.2	100	1,000	**	$848,000
IV	0.17 2:1	95.2	100	1,000	**	$848,000
V	0.15 4:1	95.8	100	1,000	**	$848,000
VI	0.08 4:1	82.2	100	1,000	**	$848,000

* Permeability values are for kx, kz = 0.01 md for all cases.
** Most likely value $2.16.

partitioned areas. These success ratios represent values for the probability or chance of success or failure of a gas well in the Devonian shales. These success ratios represent a 20-year average of data on vertical wells in Devonian shales for the state of West Virginia.

5. RESULTS:

Figures 4 through 9 present the results of the EMV analysis for each partition. Each case represents a 2,000-ft (6.1×10^2 m) horizontal well draining an area of 80 acres (3.2×10^5 m^2). The thickness of the pay zone is 100 ft (3.048×10^1 m) and initial reservoir pressure is 1,000 psi (6.9×10^3 kPa). Each gas price range was escalated 4 percent annually to account for inflation. Based on the current success ratio data, the expected monetary value after 10 years of production was determined on a before-Federal-tax basis and undiscounted to show the generated level of cash flow.

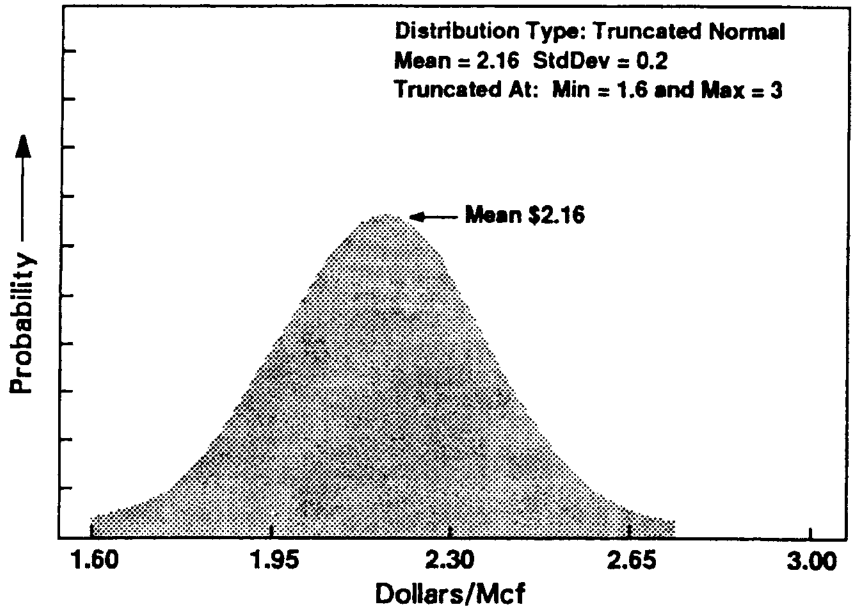

Figure 3. Gas Price Probability Distribution

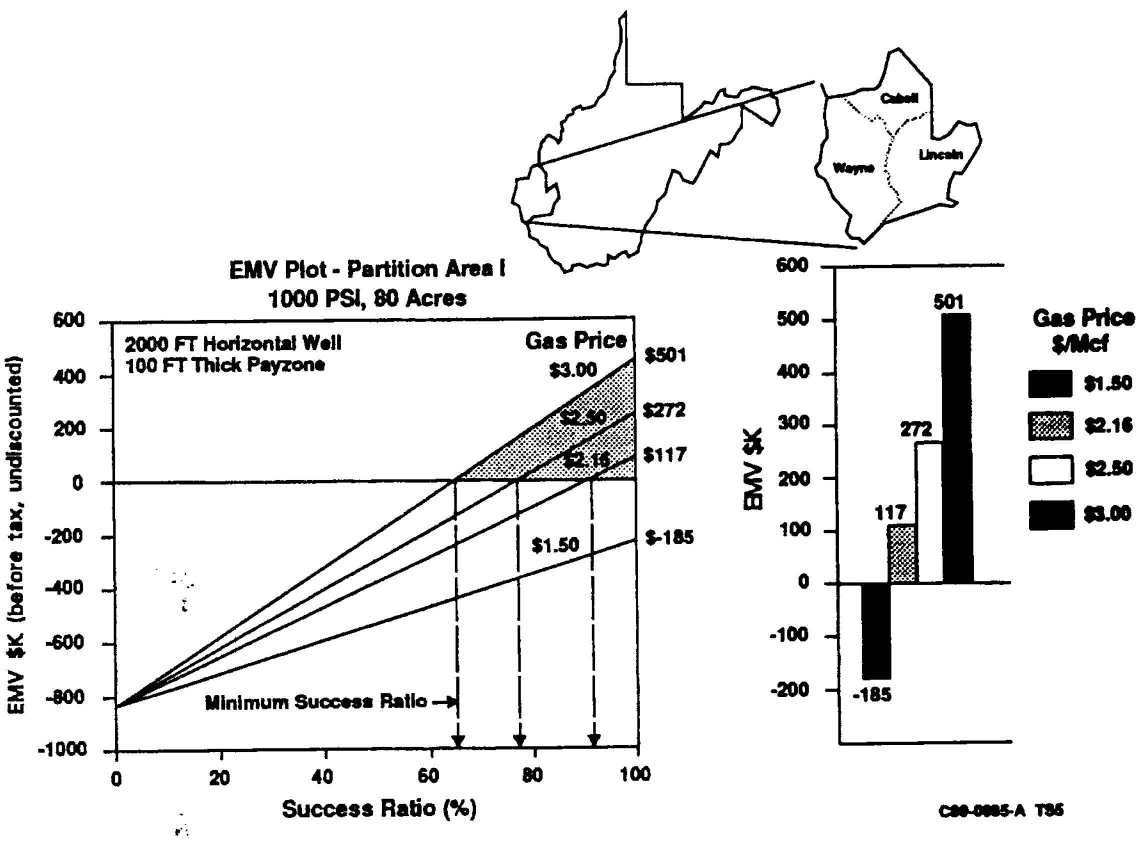

Figure 4. EMV Analysis - Partition Area I

Figure 4 shows the results for partition I. The value of $0 on the ordinate represents the break-even point for the project; that is, no net profit or gain. Figure 4 reveals at least a break-even outcome for three of the gas price ranges. The $1.50 gas case has no chance of breaking even over the 10-year period. The minimum success ratio (chance of success) for the $3.00 gas case is 62 percent. Horizontal wells must produce gas 62 percent of the time just for the project to break even. At a gas price of $2.50, a success ratio of 76 percent is needed to break even, and at $2.16, success must be 88 percent. Rates of return (ROR) and payback times were also determined to be the following:

Gas Price	ROR (%)	Payback (yrs)
$3.00	37.8	1.0
$2.50	22.1	1.6
$2.16	11.7	2.5

Given an acceptable ROR of approximately 20 percent and payback times of 2 to 3 years, a minimum of $2.50 gas is needed for this area to be economically attractive for operators. The EMV for this area at a gas price of $2.50 is $272,000, and $501,000 at $3.00.

Figure 5 shows the results for partition II. This plot reveals at least a break-even outcome for three gas price ranges; however the corresponding success ratios are higher than for partition I. The minimum success ratio needed is 70 percent for the $3.00 range, 84 percent for $2.50, and 98 percent for the $2.16 range. ROR and payback times were as follows:

Gas Price	ROR (%)	Payback (yrs)
$3.00	15.7	3.2
$2.50	8.1	4.8
$2.16	2.9	7.2

The maximum ROR and payback time for this area is 15.7 percent and 3.2 years, not quite economically attractive even at $3.00 gas. The EMV for this area is $158,000 at $2.50, and $363,000 at $3.00 gas.

Figure 6 shows the results for partition III. In this area, a break-even outcome can occur for only one gas price case. There is no chance of breaking even for gas prices in the range of $1.50 to $2.50. A minimum of $3.00 gas is needed with a minimum success ratio of 85 percent. Accordingly, the ROR and payback values are not very attractive:

Gas Price	ROR (%)	Payback (yrs)
$3.00	8.0	5.7
$2.50	2.9	7.9
$2.16	-0.8	No Payback

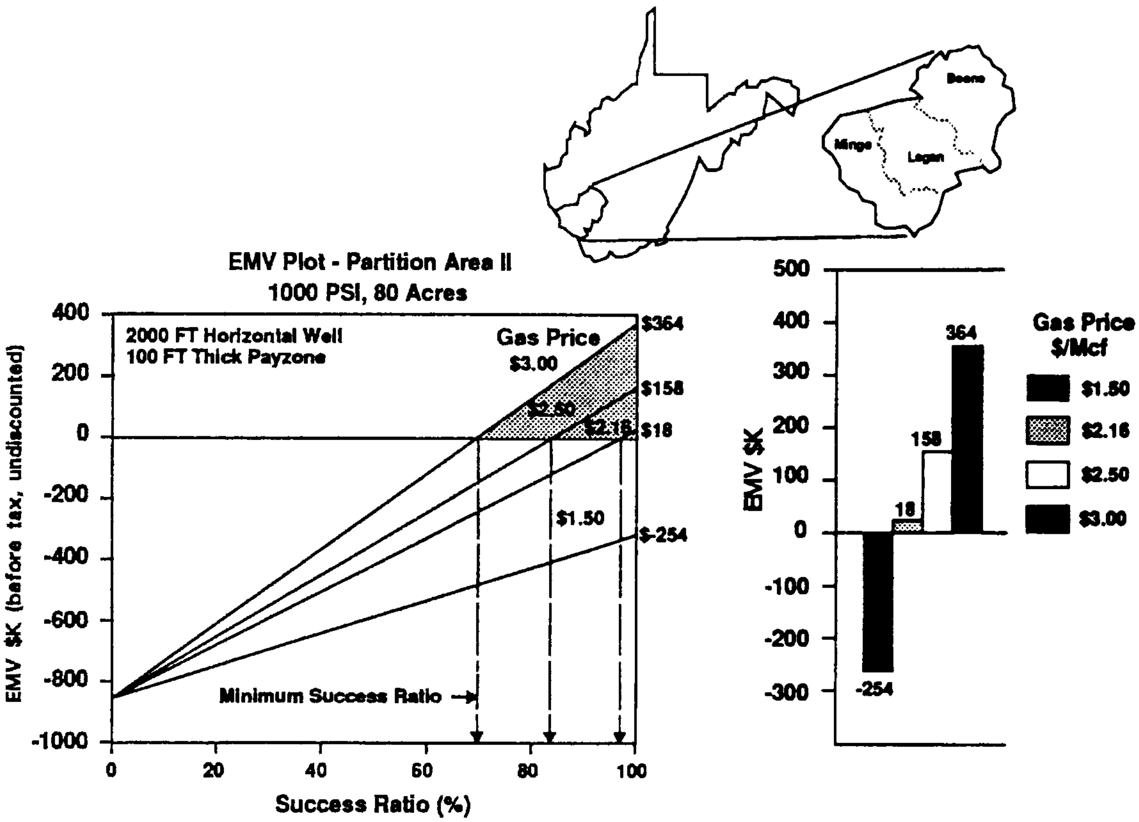

Figure 5. EMV Analysis - Partition Area II

The maximum EMV for this area is $154,000 at $3.00 gas, lower than that for areas 1 and 2.

Figure 7 shows the results for partition IV. This plot reveals a break-even outcome for at least three of the gas price ranges and with lower minimum success ratios required than for the corresponding gas price ranges in partitions I, II, and III. The minimum success ratio required is 55 percent for $3.00 gas, 66 percent for $2.50 gas, and 77 percent for $2.16 gas. ROR and payback values are as follows:

Gas Price	ROR (%)	Payback (yrs)
$3.00	27.9	1.9
$2.50	17.3	2.7
$2.16	10.2	3.8
$1.50	-3.5	No Payback

This area would be very attractive economically at $3.00 gas and marginally attractive at $2.50. The maximum EMV for this area is $696,000 at $3.00 gas, the highest value thus far.

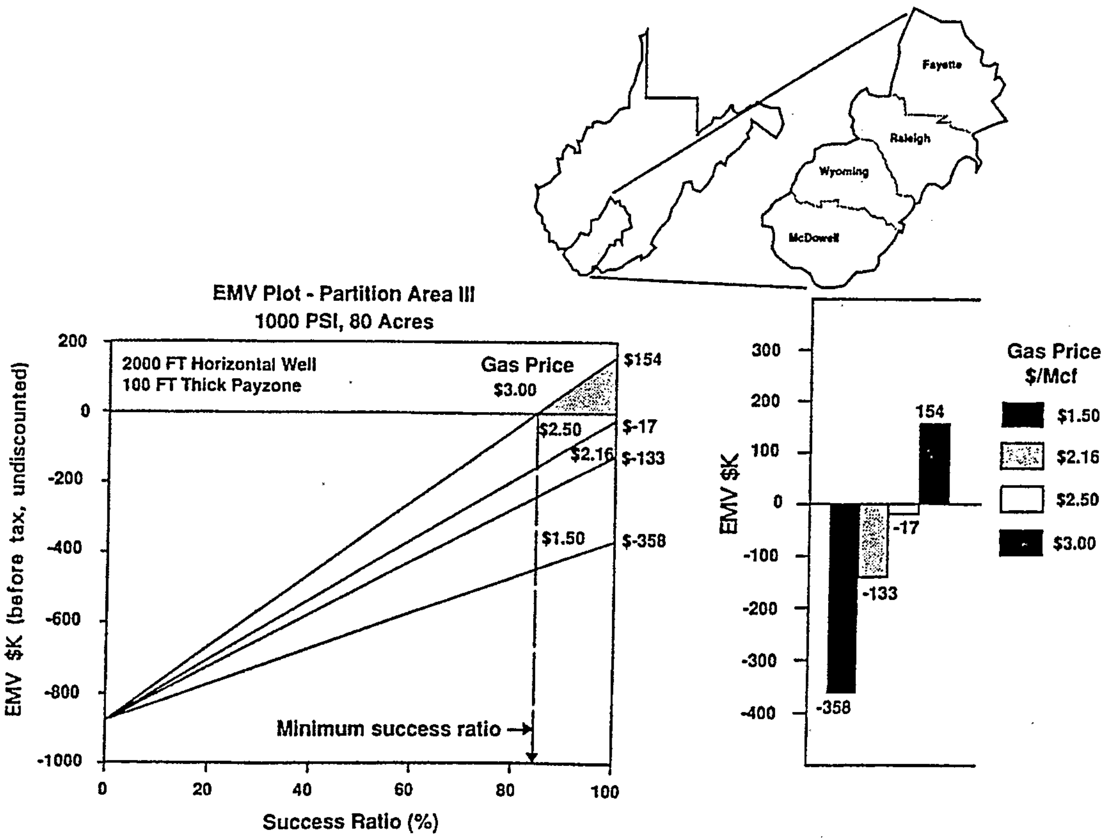

Figure 6. EMV Analysis - Partition Area III

Figure 8 shows the results for area V. A break-even outcome can occur for three of the gas price ranges. A minimum success ratio of 60 percent is needed for $3.00 gas, 72 percent for $2.50 gas, and 84 percent for $2.16 gas. A break-even outcome will not occur for $1.50 gas. ROR and payback values are as follows:

Gas Price	ROR (%)	Payback (yrs)
$3.00	26.1	2.0
$2.50	16.1	2.9
$2.16	9.4	4.1
$1.50	-3.8	No Payback

This area would be economically attractive at $3.00 gas. The maximum EMV is $562,000 at $3.00 gas.

Figure 9 shows the results for partition VI. A break-even outcome can occur for the $3.00 and $2.50 gas prices. There is no chance of a break-even outcome for the $1.50 and $2.16 cases. The minimum success ratio

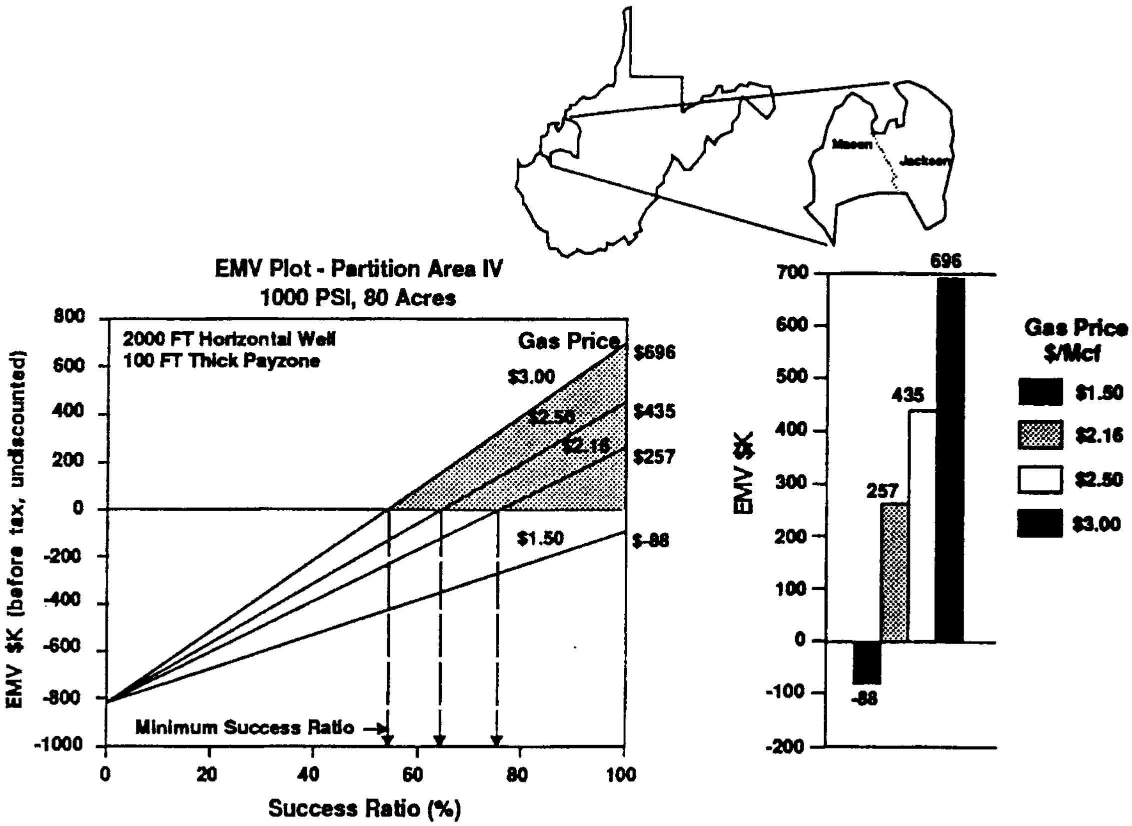

Figure 7. EMV Analysis - Partition Area IV

required for the $3.00 case is 72 percent, and 86 percent is required for the $2.50 case. The ROR and payback values are as follows:

Gas Price	ROR (%)	Payback (yrs)
$3.00	19.4	2.8
$2.50	11.5	4.0
$2.16	6.0	5.7
$1.50	-4.9	No Payback

This area would be economically attractive at $3.00 gas. The maximum EMV for this area is $333,000 at $3.00 gas.

Figure 10 is a summary EMV graph showing the results for all six partitions for each gas price. Partition IV is the most promising area, followed by partitions V and I. Partition I has a higher ROR at $2.50 gas than partition IV. This is because of the higher gas production during the early years in partition I, as indicated by the simulation results. (See Table 4.)

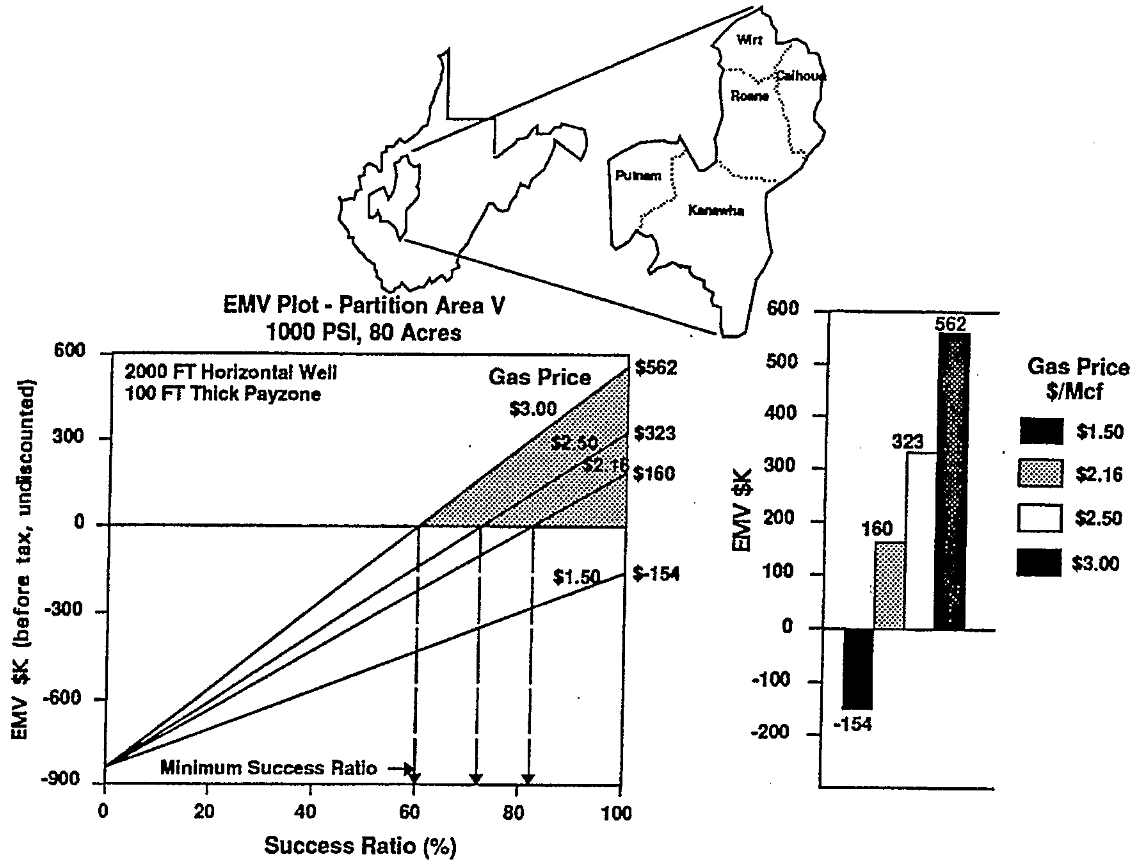

Figure 8. EMV Analysis - Partition Area V

These results also follow the trend of natural fracture spacing -- smaller (5 ft [1.5 m]) in partitions I and V, than in partitions III and VI (20 ft [6.1 m]). See Figure 11. A smaller fracture spacing translates into more effective or higher fracture permeability per reservoir volume and hence, a potentially more productive fracture network. In addition, if project guidelines target RORs of 10 to 15 percent as being attractive, as compared to the 20 percent value used in this study, then the above cases become more promising at the lower gas prices.

6. CONCLUSIONS:

1. Partitions IV, V, and I show the most promise for unstimulated horizontal well development as indicated by their respective EMV values. Stimulated horizontal wells would show even more promise.

2. Economically attractive areas reflect the natural fracture spacing present in the partition areas.

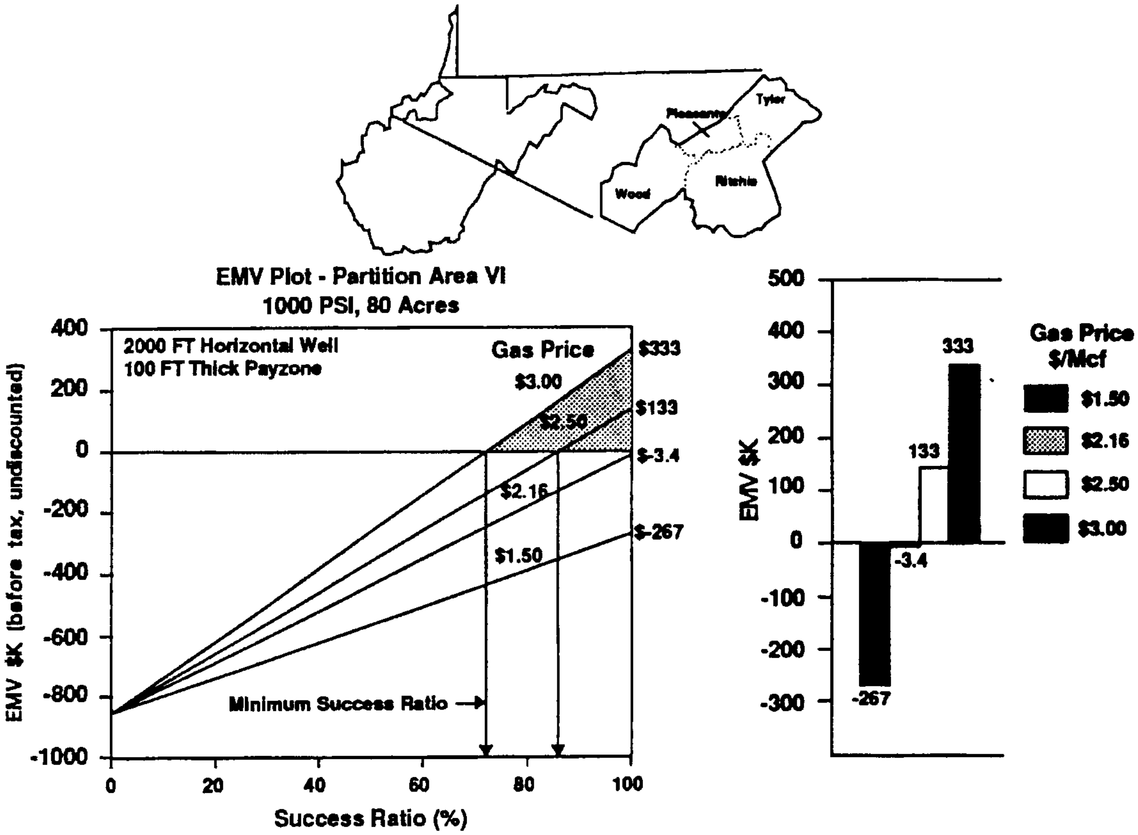

Figure 9. EMV Analysis - Partition Area VI

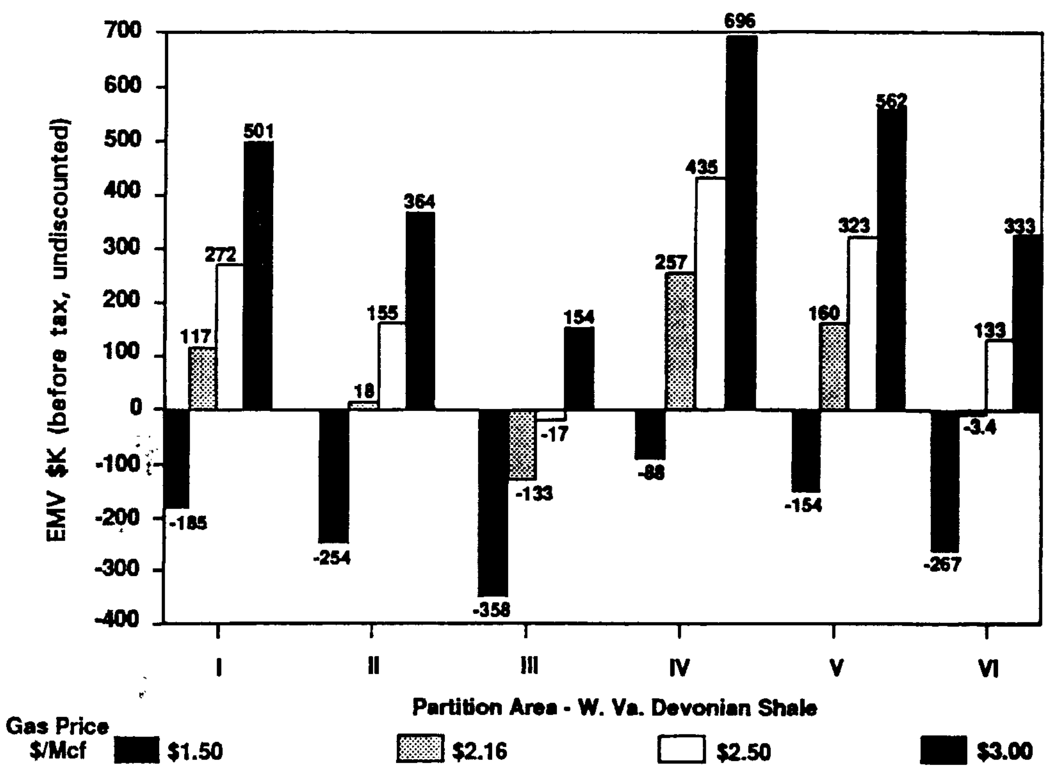

Figure 10. Summary EMV Analysis

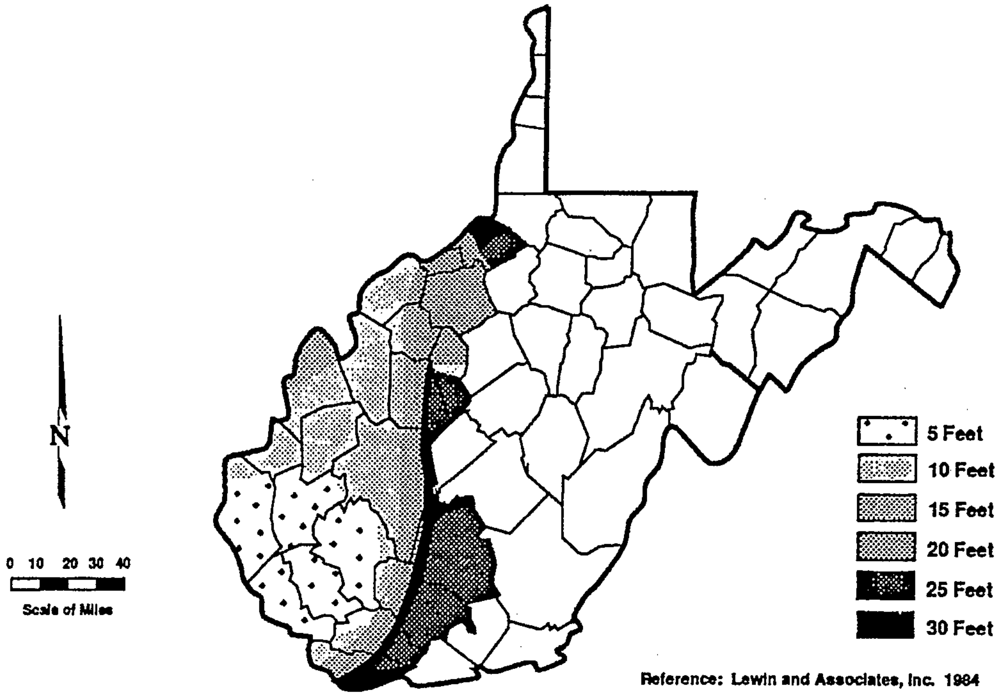

Figure 11. Natural Fracture Spacing Geologic Setting I

Table 4. Annual and Cumulative 10-Year Predicted Gas Production (Mcf)

Year	Partition					
	I	II	III	IV	V	VI
1	310,001	146,475	86,082	209,817	198,509	153,491
2	88,080	85,511	61,631	104,508	102,393	91,929
3	40,366	56,023	48,247	62,347	62,580	61,725
4	23,645	39,420	38,992	41,271	42,103	44,320
5	14,883	29,195	32,267	29,270	30,203	33,346
6	10,261	22,453	27,174	21,792	22,682	25,970
7	7,442	17,783	23,221	16,824	17,633	20,781
8	5,597	14,416	20,083	13,366	14,079	16,998
9	4,328	11,912	17,549	10,859	14,269	14,151
10	3,376	9,872	15,269	8,872	6,632	11,804
Total	507,979	433,060	370,515	518,925	511,083	474,515

SI METRIC CONVERSION FACTORS

acre x 4.046 873	E+03 = m^2
ft x 3.048*	E-01 = m
Mcf x 2831.685	E-02 = m^3
psi x 6.894 757	E+00 = kPa

* Conversion factor is exact

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APPENDIX

RATE OF RETURN -- The interest rate which equates the value of all cash inflows to the cash outlays when these cash flows are discounted or compounded to a common point in time. It is the interest rate which makes the present value of net revenue equal to the present value of the investments.

Calculation of rate of return is a trial and error process which begins by selecting an interest rate and discounting all the cash flows back to time zero. When the sum of all investments (-) and revenues (+) equals zero, then the discount rate used is the correct rate of return.

$$C_0 + S_1[\ 1/(1+i)^1\ ] + S_2[\ 1/(1+i)^2\ ] + \ldots\ldots + S_n[\ 1/(1+i)^n\ ] = 0$$

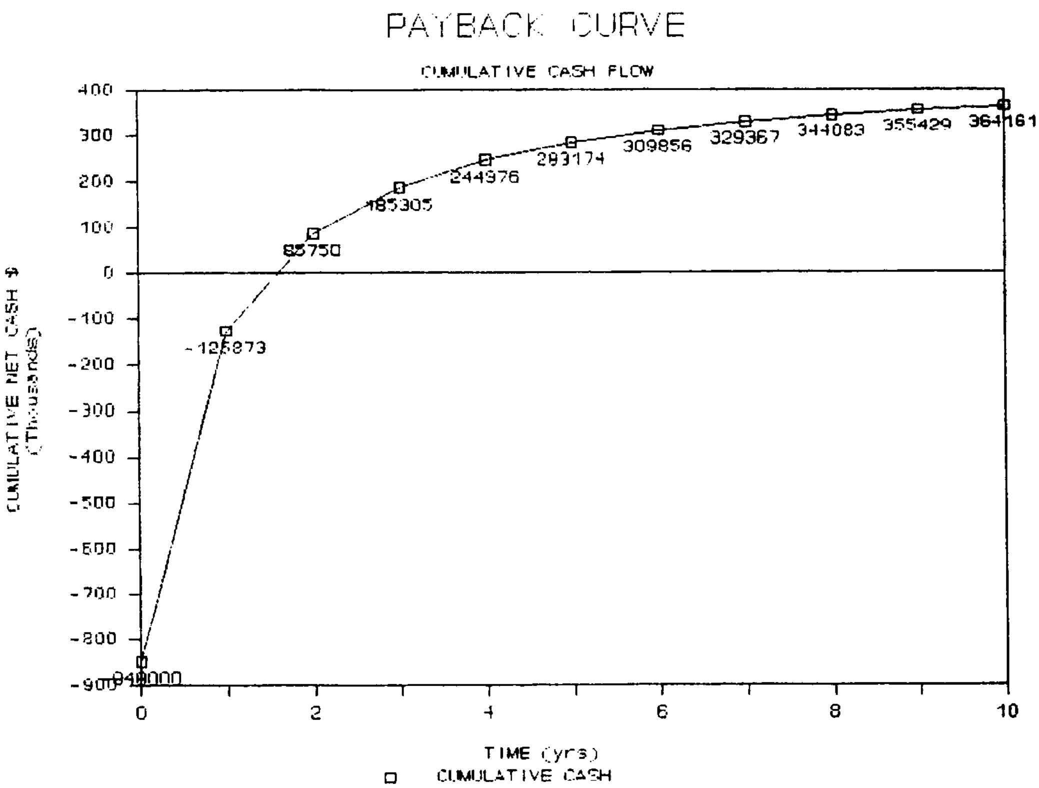
C_0 = initial investment at time zero
S_j = net cash flow received at end of period j
n = total number of periods in cash flow
i = interest (discount) rate, decimal fraction

Gas Production (Mcf) Year	Area I	Net Cash Flow	Cumulative Cash Flow	$1/(1+i)^j$ $i = 0.221$	Net Cash Flow (discounted)
0		-848,000	-848,000	1.000	-848,000
1	310,001	722,127	-125,873	0.819	591,422
2	88,080	211,622	85,750	0.671	141,998
3	40,366	99,555	185,305	0.549	54,655
4	23,645	59,671	244,976	0.449	26,792
5	14,883	38,198	283,174	0.368	14,075
6	10,261	26,682	309,856	0.302	8,052
7	7,442	19,511	329,367	0.247	4,822
8	5,597	14,716	344,083	0.202	2,979
9	4,328	11,345	355,429	0.166	1,881
10	3,376	8,732	364,161	0.136	1,187
					0

Total: 507,979
Rate of Return: 22.1%

PAYOUT -- Payout or payback time is defined as the length of time required to receive net revenues equal to the investment, the time needed to get the invested capital back.

Graphically, payout time is the point where the cumulative cash flow curve crosses the $0 line. In this case, the payout time is approximately 1.6-1.7 years.



APPLICATION OF REMOTE GEOLOGIC ANALYSIS TO EXPLORATION OF GAS IN NATURALLY FRACTURED RESERVOIRS IN WEST VIRGINIA

1. CONTRACT NUMBER: 896/AB0505

   CONTRACTOR: Extraction Science and Engineering Branch
   OBAS
   U.S. DOE/METC

   CONTRACTOR PROJECT MANAGER: Thomas H. Mroz

   PRINCIPAL INVESTIGATOR: Thomas H. Mroz

   METC PROJECT MANAGER: Albert Yost

   CONTRACT PERIOD OF PERFORMANCE: October 1, 1988, to September 30, 1989

   CONTRACT NUMBER: 89MC-26217.000

   CONTRACTOR: Battelle Memorial Institute, Pacific Northwest Laboratories
   Battelle Blvd.
   P.O. Box 999
   Richland, WA. 99352
   FTS-444-3685

   CONTRACTOR PROJECT MANAGER: Mr. Paul Pak

   PRINCIPAL INVESTIGATORS: Michael Foley
   Dennis Beaver

   METC PROJECT MANAGER: T. H. Mroz

   CONTRACT PERIOD OF PERFORMANCE: April 1, 1989 to September 30, 1989

2. SCHEDULE/MILESTONES:

Attend METC Contractors Workshop	April 1989
Complete SW West Virginia Study	
Coplanar Analysis	May 1, 1989
Final Report	June 30, 1989
Initiate Western Gas Sand Study	July 1, 1989
Progress Report	September 30, 1989

3. OBJECTIVES:

   The major objective of this program is to evaluate a software package developed by Dr. Jay Eliason that maps linear geologic features that influence gas production trends. The software package identifies fault and fracture planes in the earth's crust from digital topographic data and allows their locations to be compared with subsurface geology. The purpose is to determine the correlation of the linear features to structure and their influence on gas production trends.

The project is a two-fold study with personnel at Battelle Pacific NW Laboratories (PNL) accomplishing the Remote Geologic Analysis (RGA) software analysis and DOE/METC developing the detailed three-dimensional geologic model and reservoir analysis. Upon completion of the individual efforts the output is integrated for correlation of the lineament plane patterns and locations identified in the Geologic Spatial Analysis (GSA) to the three-dimensional geologic model. The results will determine if a correlation exists between the geologic structure and the mapped planes and identify the planes as joints, faults or zones of highly fractured rock.

The next step in the study is to map the intersection of the lineament planes and project them to the reservoir level and compare the intersections to production. The results will show if a correlation exists between highly fractured zones associated with one or more plane intersections and higher than normal gas flows.

The final effort will be to apply the method to other areas of unknown gas production or geology and determine if enhanced fracture porosity can be mapped in the tight formations.

4. BACKGROUND:

A software package called Geologic Spatial Analysis (GSA) was developed by Dr. Jay Eliason and is presently patented by Mrs. Valeri Eliason and the U.S. DOE. The program was designed to calculate the classical three-point method for finding the attitude of a plane representing a geologic feature on a map or from topographic data. It assumes that topography or the geomorphology of a given area is controlled by faults and joints in the earth's crust that manifest themselves as linear features at the surface (Figure 1). The program finds the low points in digital elevation model data (DEM) of topography available from the U.S. Geological Survey (USGS) in 7.5-minute quadrangle format (Figure 2). Then, vectors are calculated for the strings of low points (Figure 3) and all vectors are compared to each other to determine which are coplanar. An interactive system has been developed to scan the planar sets by dip angle increments and strike orientation. This system can be varied by the interpreter to view the angular grouping (Figure 4). This method is used to (1) identify the planes that are parallel on the map projection and that can be correlated to geologic structures at the same scale, and (2) determine if they are associated with specific geologic deformations in the rocks of interest. These planes are then plotted in 3-D stereo projections (Figure 5).

PNL has been attempting to improve the capabilities of the software to analyze other sources of synoptic geophysical data and imagery. The system development is supported by the U.S. DOE's Office of Basic Energy Sciences (OBES) and is called the RGA system (Foley, Personal Comm.). The system has been used in a number of other applications such as evaluating mineral occurrences (Eliason J. R., and V. L. Eliason), evaluating nuclear waste disposal and power generation sites (Foley et al. 1988), and determining the effectiveness of analyzing other types of digital remote sensing data (see selected bibliography).

This method is unique in that it eliminates the interpreter in the analysis of the basic topographic data and the results can be duplicated from the same data set. It has been our experience with other lineament surveys that the results are seldom duplicated and that the study area is not uniformly covered (Pratt et al. 1985).

The present study of a four quadrangle area in southwest West Virginia was a result of a workshop on lineament analysis sponsored by DOE/METC in Morgantown, West Virginia.

5. PROJECT DESCRIPTION:

This paper represents the effort on the Big Creek 7.5-minute quadrangle in the southwest West Virginia study area in Lincoln and Logan counties, West Virginia (Figure 6). The Big Creek area was selected as a trial to determine the amount of computer resources that would be necessary to run the RGA on the complex dendritic drainage pattern in the plateau province of the Appalachian Basin. PNL personnel obtained the DEM information from the USGS and performed a quality control analysis of the digital data prior to starting the RGA portion of the project. At the same time, DOE/METC personnel began accumulating the geologic, geophysical, and gas well data necessary to construct the three-dimensional geologic structure model. Information on the area was available from earlier studies by the Gas Research Institute (GRI), petroleum companies operating in West Virginia, and eastern gas shale studies sponsored by DOE/METC.

PNL identified the major lineament planes in the study area without using the detailed geologic information being compiled at METC. The purpose was to prevent any bias the operator might have. When the individual studies were completed, the results were compared to determine if a correlation existed between the plane sets and major faults, joints, and cross strike discontinuities (CSDs) identified in the separate studies.

The geologic study combined the efforts of several petroleum geologists, engineers, and geophysicists in accumulating and analyzing the data. The bulk of the information was resident on the computer system at DOE/METC in the form of well data on formation log tops, completion, and production values. Well density, seismic line, and geologic cross sections are identified in Figure 7. The seismic sections indicate that several large faults occur near the northern portion of the Big Creek Quadrangle (Figure 8). The seismic section shows that the faults penetrate the Huron Shale, which is the prime source and reservoir rock in this area. A well section (Figure 9) was also drafted to determine the effect of the faulting on the shallower Berea Sandstone and Greenbrier Limestone production zones. The cross section definitely indicates faulting in the shallow formations immediately above the basement faults identified on the seismic sections. This indicates that these large faults affect the topography at the surface.

Geologic structure maps were created on the shallower production horizons, and cumulative production from shale wells was contoured with the hope that other linear trends on these surfaces would define fault and or joint systems (Figures 10 and 11). These maps also show linear features that fit with structures identified on surface features; the surface features identified from geologic mapping and Landsat mapping by the West Virginia Geological and Economic Survey. The major trends are defined by a CSD at about N 20° W, a graben on the north side of the fault system identified by the seismic, well sections, and high gas production trends shown on Figure 11.

Other data not noted on the figures includes the axes of the Warfield Fault to the south and the folds affecting the coals in the near surface (with extremely different strikes of N 70° E and N 10° W).

The plane sets were plotted on mylar overlays at a scale of 1" = 2,000'. The overlays were then compared with the structure maps and the production contour map to determine if a correlation existed between the surface expressions identified and subsurface (-3,000 feet) faults. It became apparent that more detailed analysis should be done on the geometric relationships of the planes and their intersections, and on well production and geologic structural anomalies.

6. <u>RESULTS/ACCOMPLISHMENTS</u>:

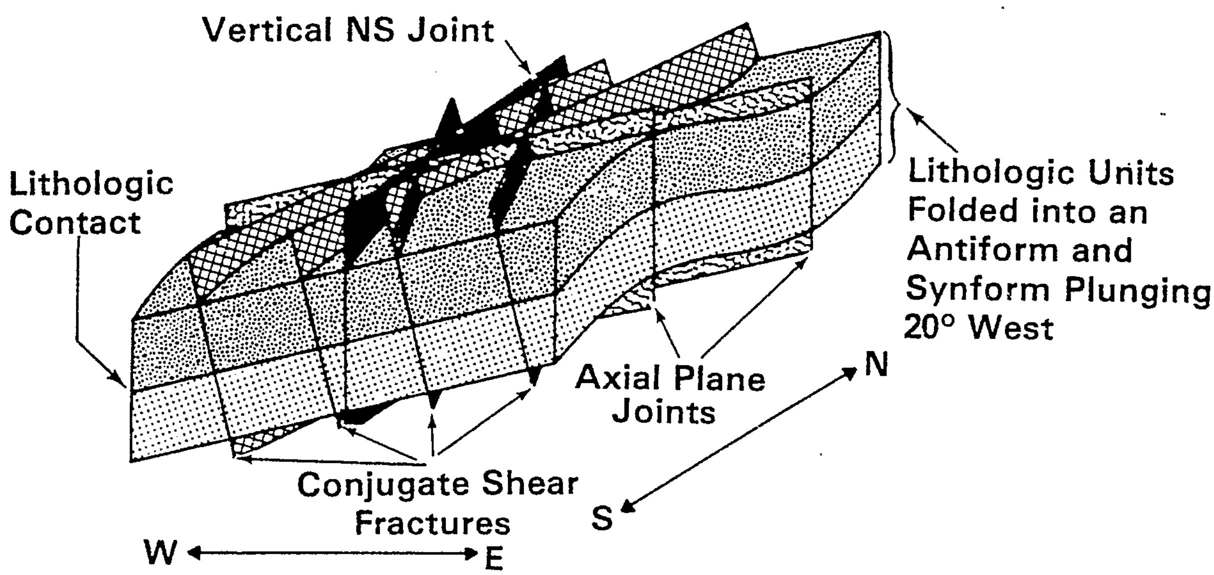
Only the high angle planes from the RGA analysis were used for comparison because most of the joints and faults mapped in oriented cores from the eastern gas shales project indicated a near vertical attitude. The major plane sets used for correlation to the structures identified in the three-dimensional geologic model are presented in Figure 12. The plane sets overlie the northeast striking fault system on the southside of the graben and the CSD, and two other sets match the fold axes mapped on surrounding quadrangles. The RGA analysis has identified more faults and a wider CSD system than that identified by Landsat.

The fault system associated with the graben and northeast trending production is the dominant feature that controls the shale gas reservoir in the area. The plane sets indicate that the fault system continues southward, and the intersection of these fault planes with the CSD may be the cause of concentrated high gas flows shown on the production map (Figure 11). The CSD is also represented as a much wider feature (2 miles) by the plane sets than on the Landsat maps (interpretation) or on the structure maps (the anomalous zone of high and low structures).

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

The remaining three quadrangles will be analyzed with the RGA package and integrated with the three-dimensional geologic model in the coming months. The structure maps, surface topography, and production data are being integrated with the projections of the lineament planes in a 3-D block diagram (Figure 13) to show the geometric association of these features. During the summer of 1989, the area will be mapped for systematic

Digital terrain models are typically complex and few, if any, areas exist in which all of the fracture and bedding planes are known. Development of digital techniques for structural analysis required having a digital terrain model in which all fracture and bedding orientations were known. Also the model size had to be small enough to allow for rapid analysis and yet complex and large enough to provide a viable test data set for program development. A model was designed with two folded layers having an antiform and synform with axial planes striking east-west and fold axes plunging 20° to the west. These layers include two conjugate fracture sets striking N30°W and N30°E which are normal to the bedding plane and vertical east-west longitudinal fracture planes on the antiform and synform axes. Also there is a vertical fracture trending north-south across the model.



Assumption:

- The vertical NS and EW fractures dominate the erosional pattern
- The lithologic unit below the contact is the most competent unit. Therefore the erosion along the contact produces topographic lows along the contact
- The NNE and NNW conjugate fractures dipping to the E control minor sidewall topographic depressions

Figure 1. Simulated Topography Model

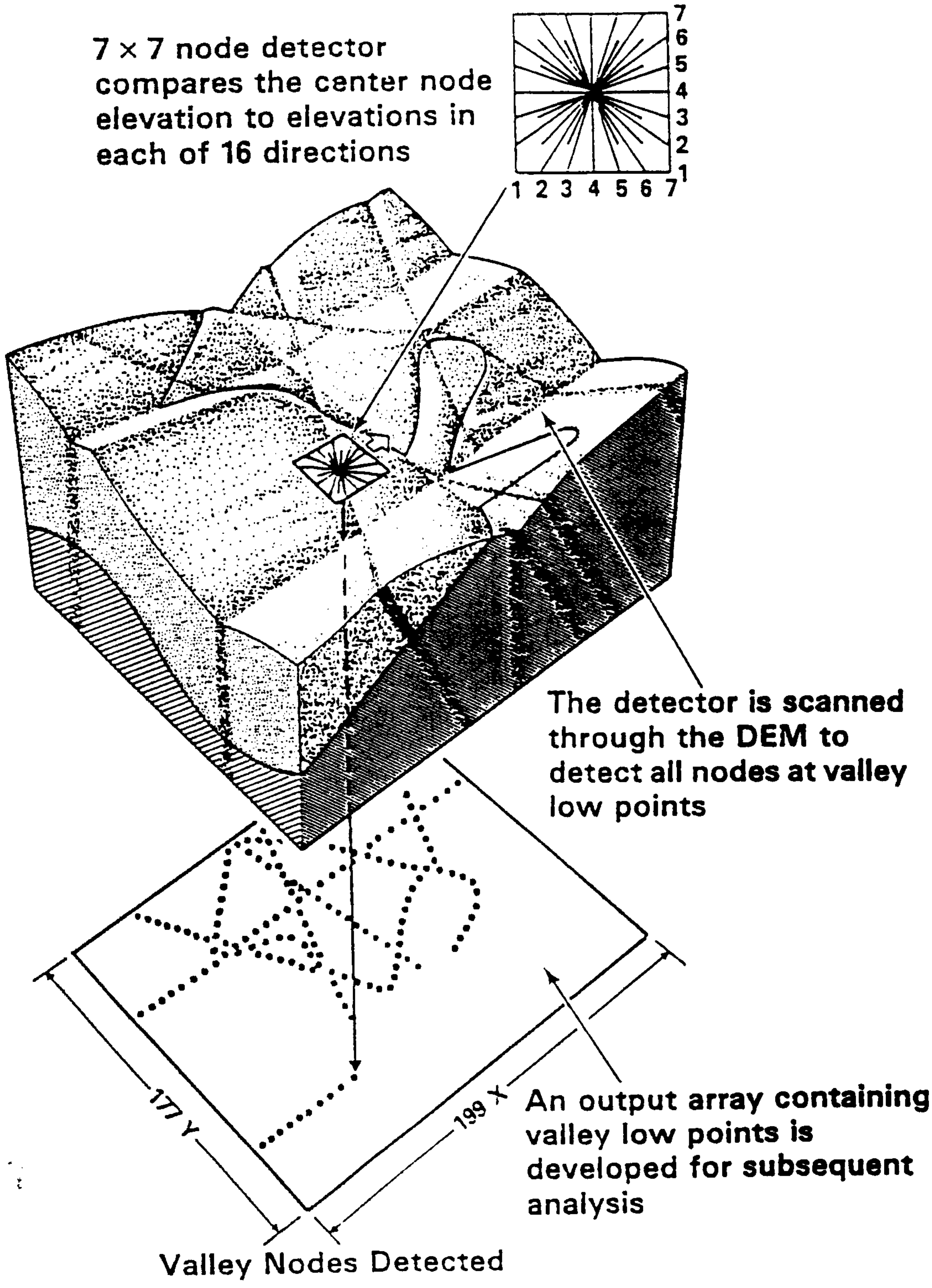
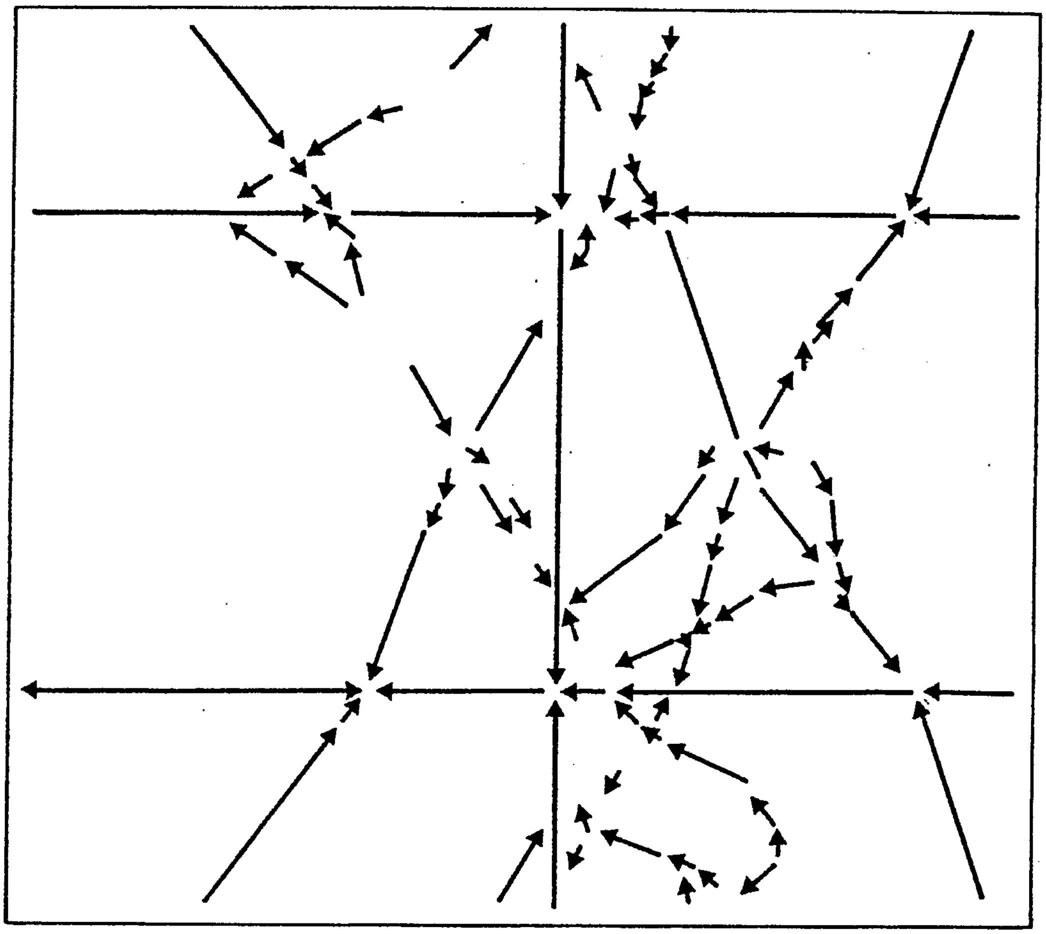


Figure 2. Detection of Topographic Lows

The valley nodes detected from the DEM are correlated into contiguous strings and colinear segments of these valley strings are fit with vectors for subsequent analysis.

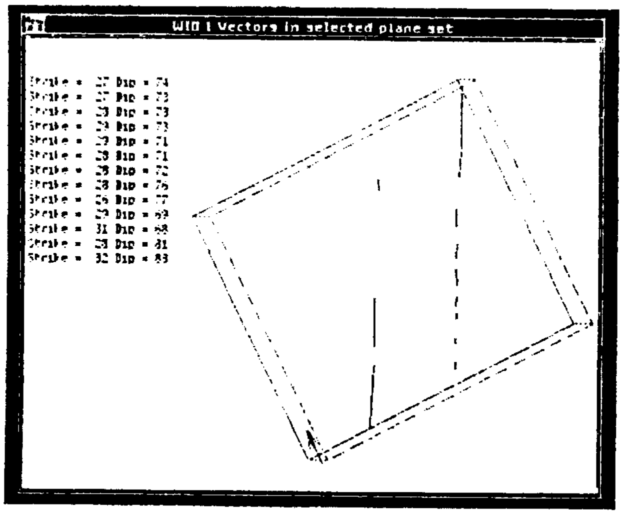


Vector segments produced from analysis of the Simulated Topography that are colinear in trend and plunge to within 10°.

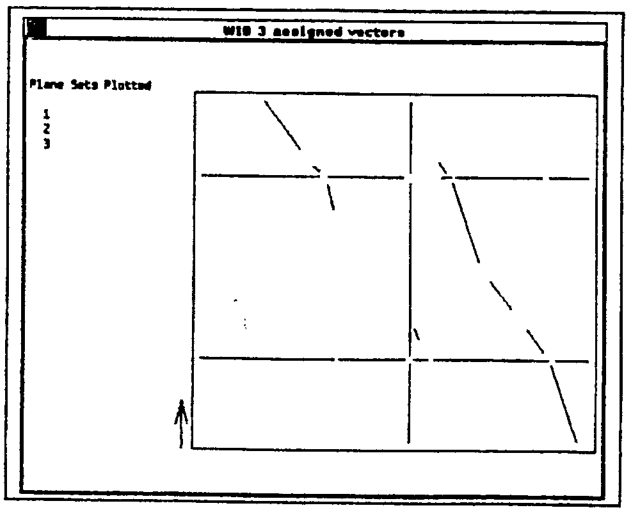
Figure 3. Vector Fitting of Topographic Lows

Coplanar analysis using the vector cross product algorithm with a coplanar divergence of 5° results in detection of all of the simulated topography model planes and the lithologic contact. The coplanar output analysis program has been developed to provide the user the ability to interactivily select, display, and model dominant coplanar correlations.

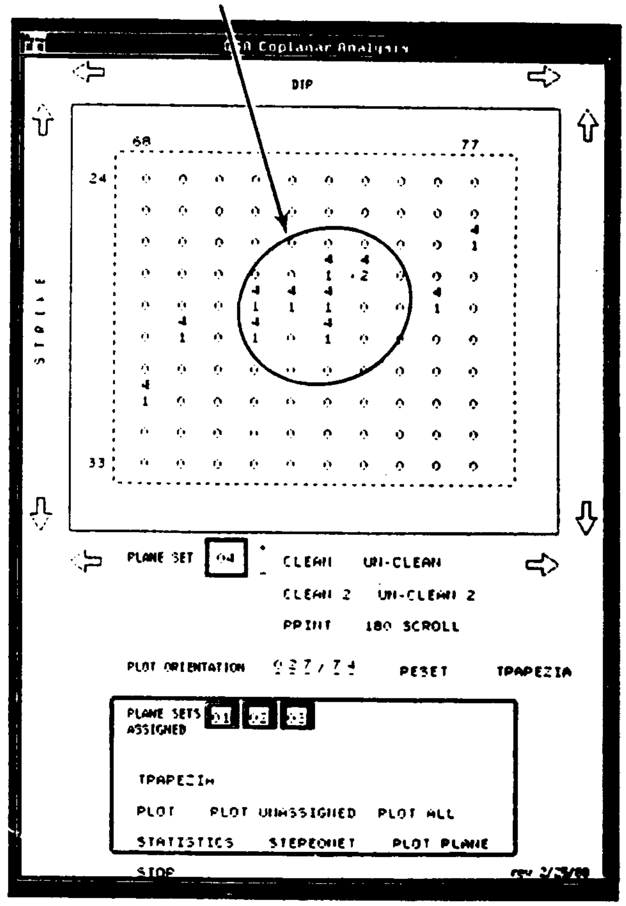
Display of plane set 4 vectors



Display of plane sets 1, 2, and 3



Identification of a dominant cluster of coplanar detections in the sorted 1° by 1° file. (The NE trending conjugate shear fractures from the simulated topography model.) Selected as plane set 4



Examples of interactive display windows.

Figure 4. Coplanar Analysis

The coplanar output analysis program allows the user to develop a three-dimensional model of the downward projection of selected plane sets. This initial modeling capability is now being evaluated and future advanced hardware and software systems are expected to make these models the primary output from the spatial analysis techniques.

Models of the Simulated Topography Analysis:

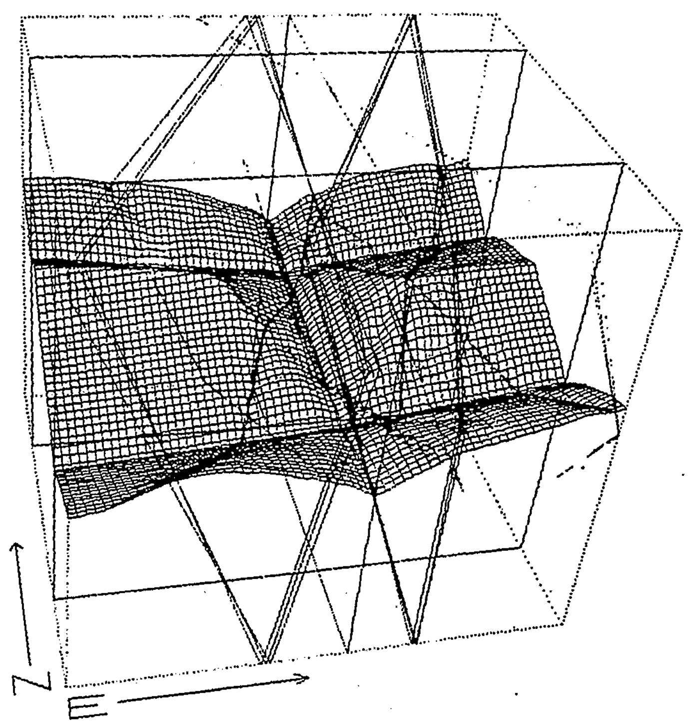


Figure 5. Coplanar Output Analysis Model

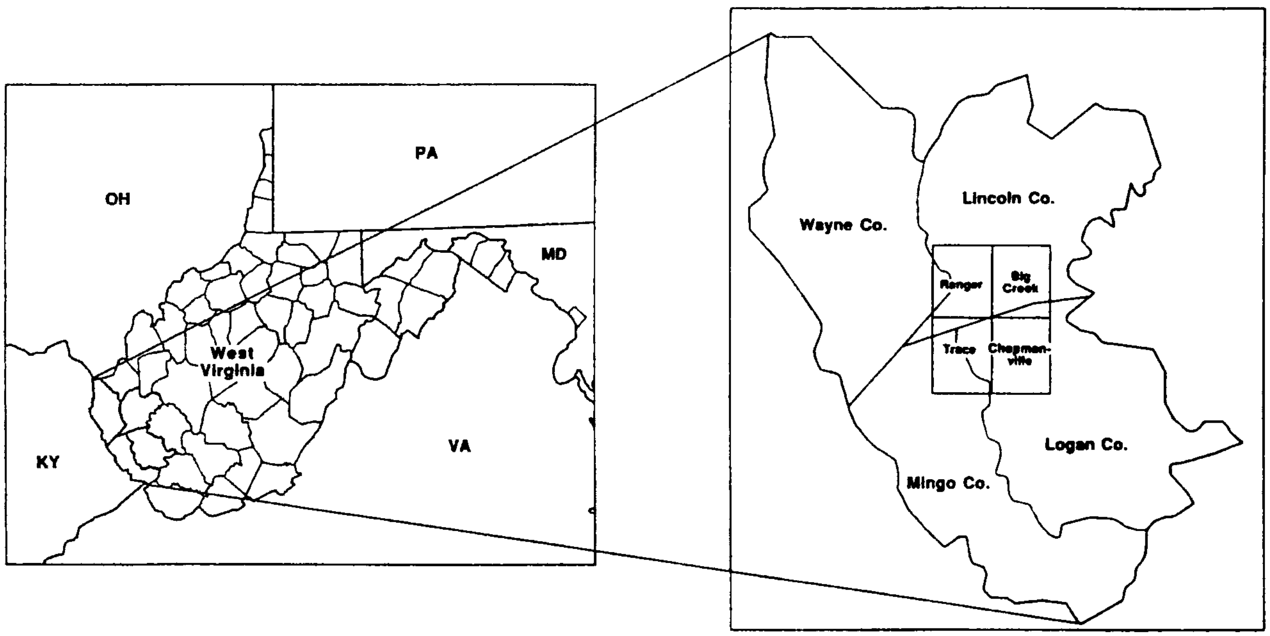


Figure 6. Location Map of METC Study Area 1

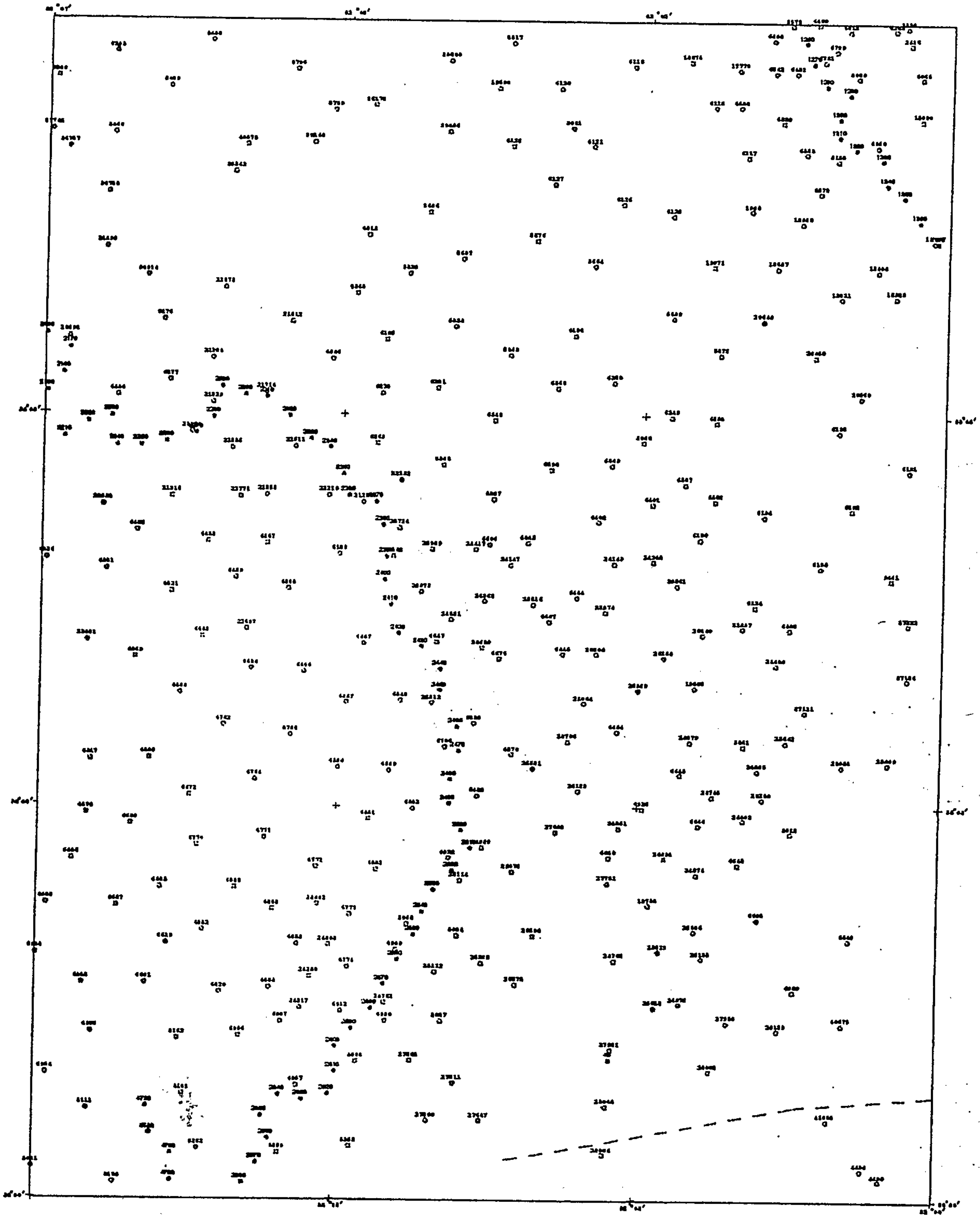


Figure 7. Well Control Location Map

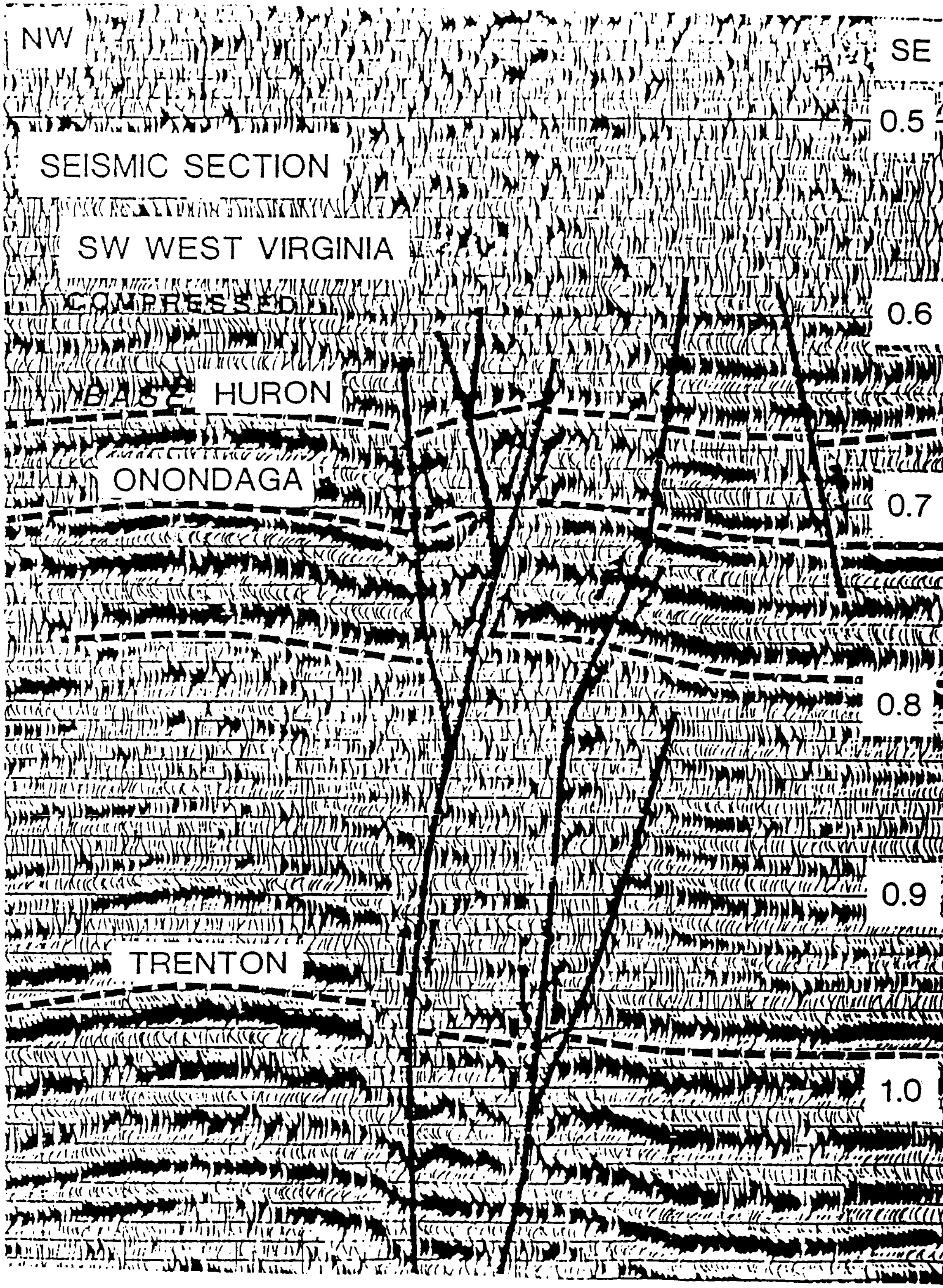


Figure 8. Seismic Cross Section

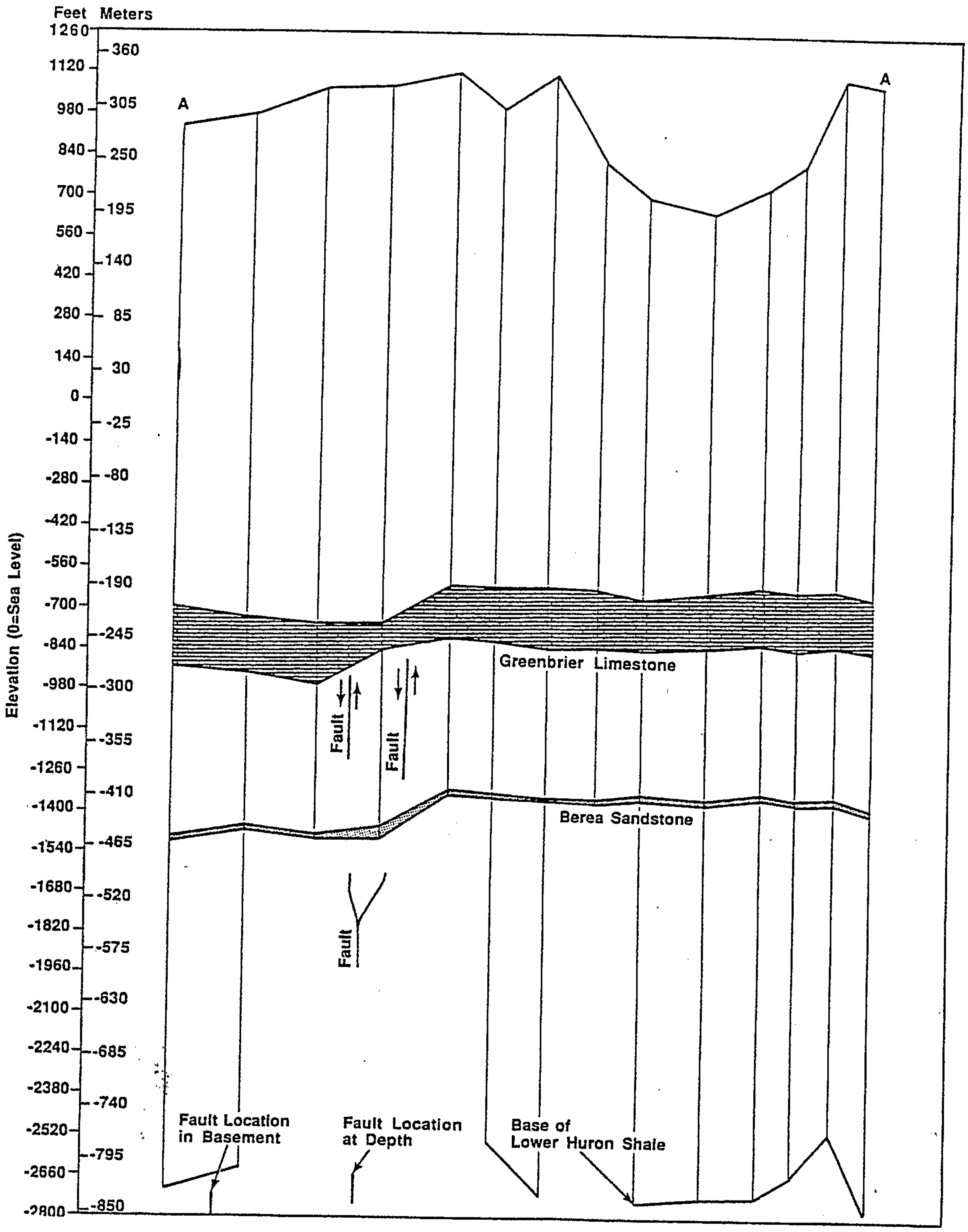


Figure 9. Well Cross Section

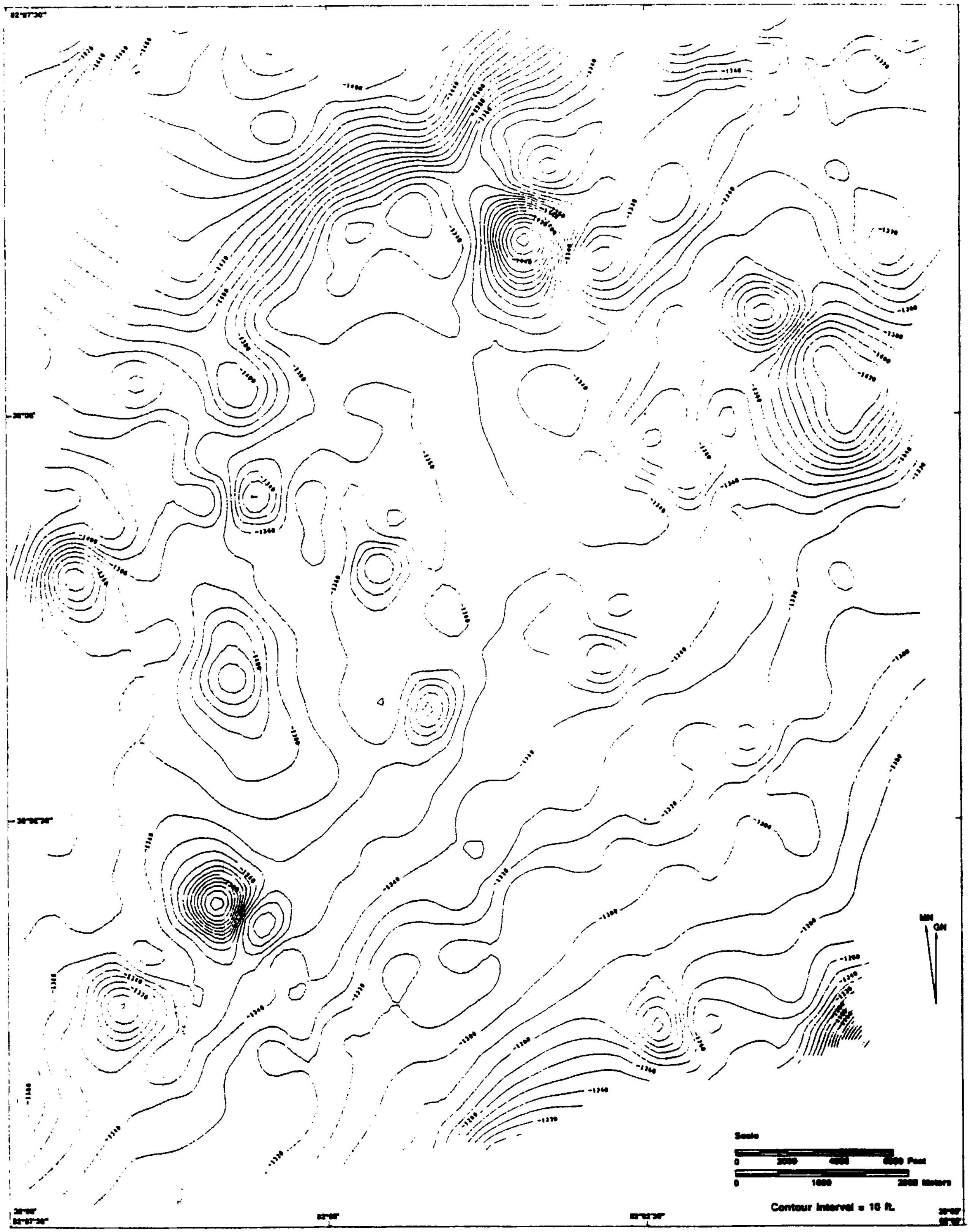


Figure 10. Structure on Top of the Berea Sandstone

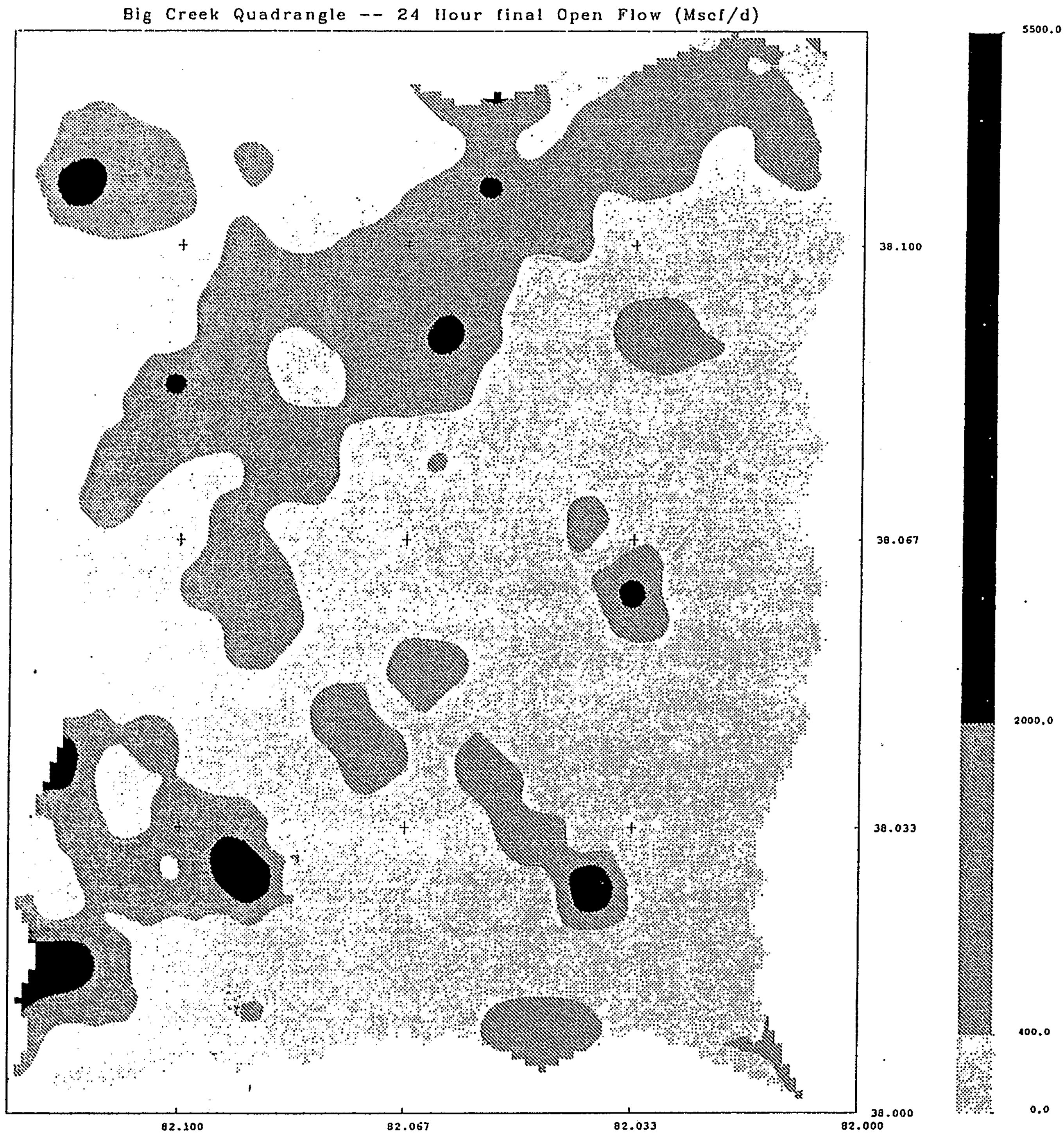


Figure 11. Gas Production Trends

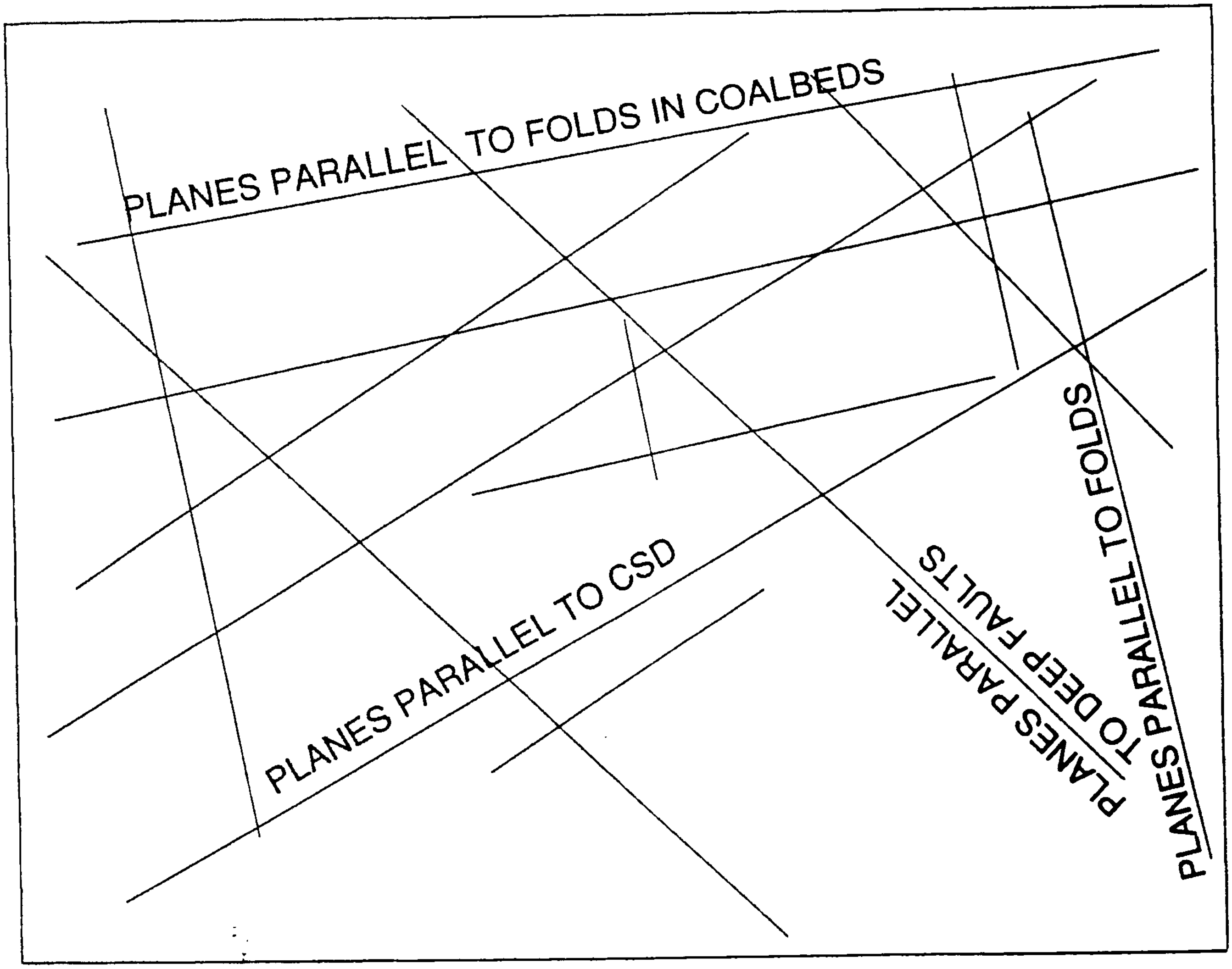


Figure 12. Mapped Locations of Lineament Plane Sets

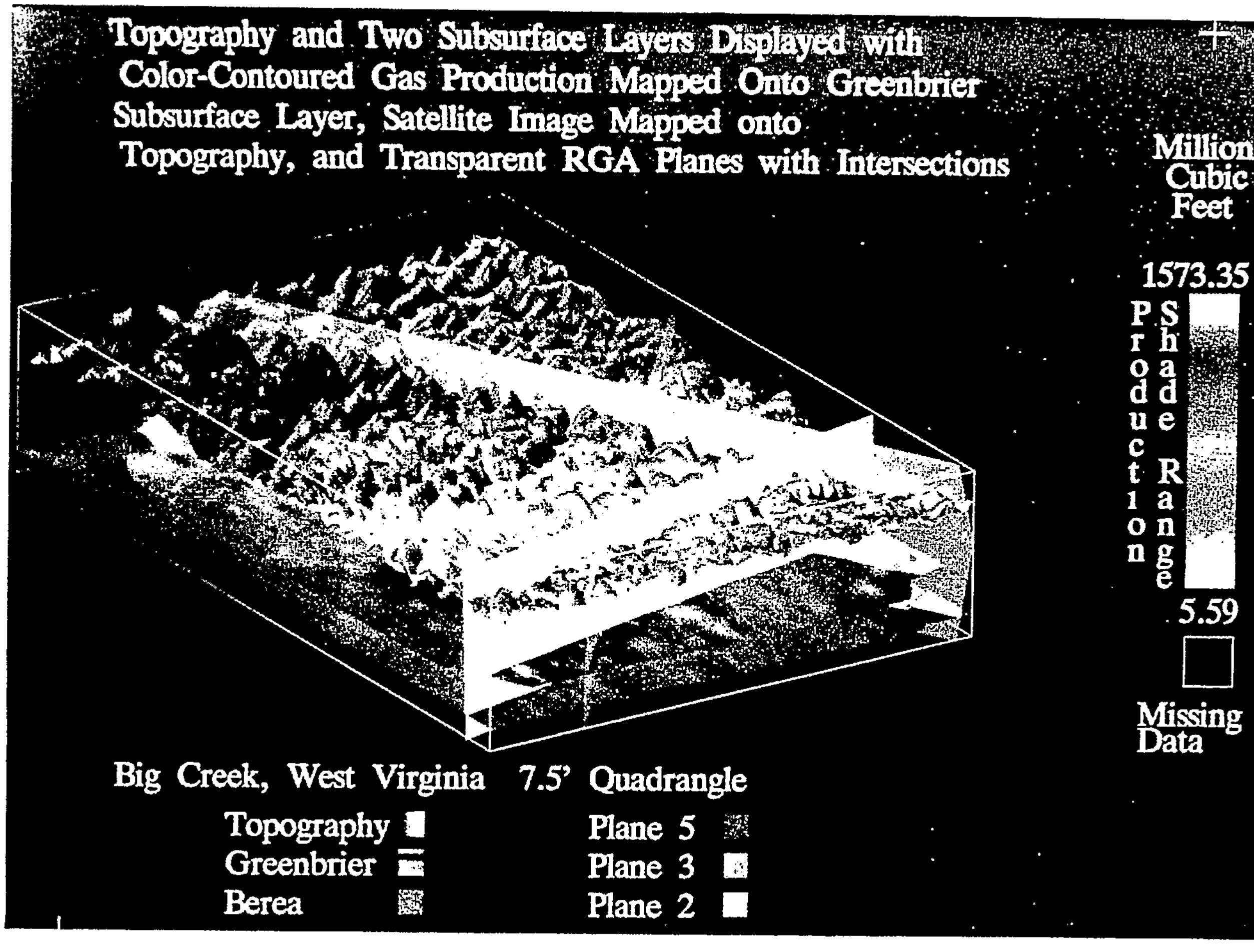


Figure 13. Three-Dimensional Graphic Projection

joint sets and any other structure that might correlate to the distribution of the remaining plane sets in the original study. For example, the thrust faulting associated with Allegheny deformation and swings in the fold axes may relate to a younger sequence that can be correlated to the less prominent plane sets.

The RGA analysis will also be run on some future horizontal well sites to see if the study is repeatable across the Basin. This may be an efficient tool for mapping basement faulting at much less expense than by acquiring seismic data in the complex topography of the Appalachian Basin.

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