# MULTI-STRATA EXPLORATION AND PRODUCTION STUDY

Final Report

Federal Energy Technology Center
U.S. Department of Energy
Morgantown, West Virginia

Performed Under Contract No. DE-AC21-89MC26026

by

The College of West Virginia
Beckley, West Virginia

October 15, 1998

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# 1.0 EXECUTIVE SUMMARY

## 1.1 Phase I Activities

Phase I, the exploration and development phase of the project, consisted of compiling and analyzing relevant geological and gas production information in a four-quadrangle area of Raleigh County, West Virginia, ultimately narrowed to the Eccles, West Virginia, 7-1/2 minute Quadrangle. The analysis identified key parameters contributing to the accumulation and production of natural gas in Raleigh County, developed analog models relating geological factors to gas production, and identified specific sites to test and verify the analysis methodologies by drilling. Based on the Phase I analysis, five sites were identified with high potential for economic gas production.

In the exploration model, three major elements were considered as significant factors associated with a high potential for hydrocarbon production. These elements; the generation of resource, the formation of a reservoir, and the presence of favorable structural features; are represented graphically in Figure 1.0.1. Each corner area pattern of this figure represents optimum conditions for one of the elements of the exploration model, with overlapping patterns representing the existence of two or more elements. These patterns were incorporated into the maps developed for the study area. Highest potential for economic gas production could be expected in those regions where all the elements are combined at their best potential. This optimum or near-optimum condition is depicted by the pattern at the center of Figure 1.0.1. The objective of the program was to locate areas where satisfactory conditions occurred and to verify the analysis by drilling and completing one or more wells.

Figure 1.0.2 illustrates the results of an intense geologic study of the Eccles Quadrangle, in Raleigh County, West Virginia, and shows areas of high potential for gas production near the center of the map. Lease ownership and existing well information were reviewed to locate five drill sites in or near the optimum area (Figure 1.0.3). When overlaid on the Component Optimization Map (Figure 1.0.4), each site is shown to be within or near the optimized area.

## 1.2 Phase II Activities

Phase II activities were initiated with a lineament study of the four-quadrangle area covered by the Phase I study followed by a seismic line run along Sandlick Creek. The lineament study mapped large features observed on Landsat imagery, high-altitude-color and near-infrared photography, and sidelooking airborne radar (SLAR) imagery. The features mapped in the area did not correlate with any structural features previously mapped and oriented in the immediate project area. A major trend of a nearly north-south orientation correlated generally with the Grenvillian basement faulting orientation, and the orientation of the basement block mapped on the Berea and Big Lime formations

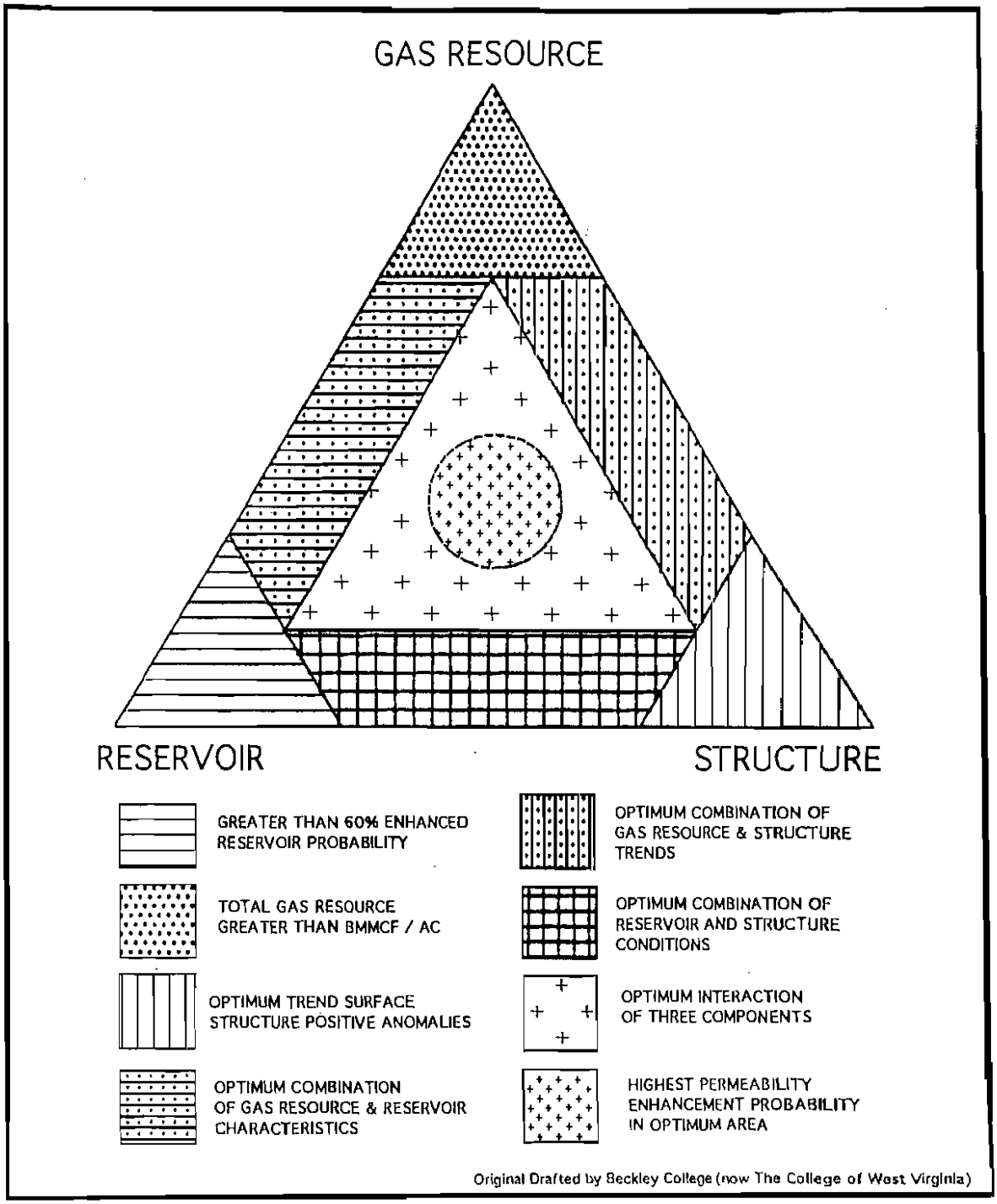



Figure 1.0.1 - Major Elements Associated with High Potential for Hydrocarbon Production

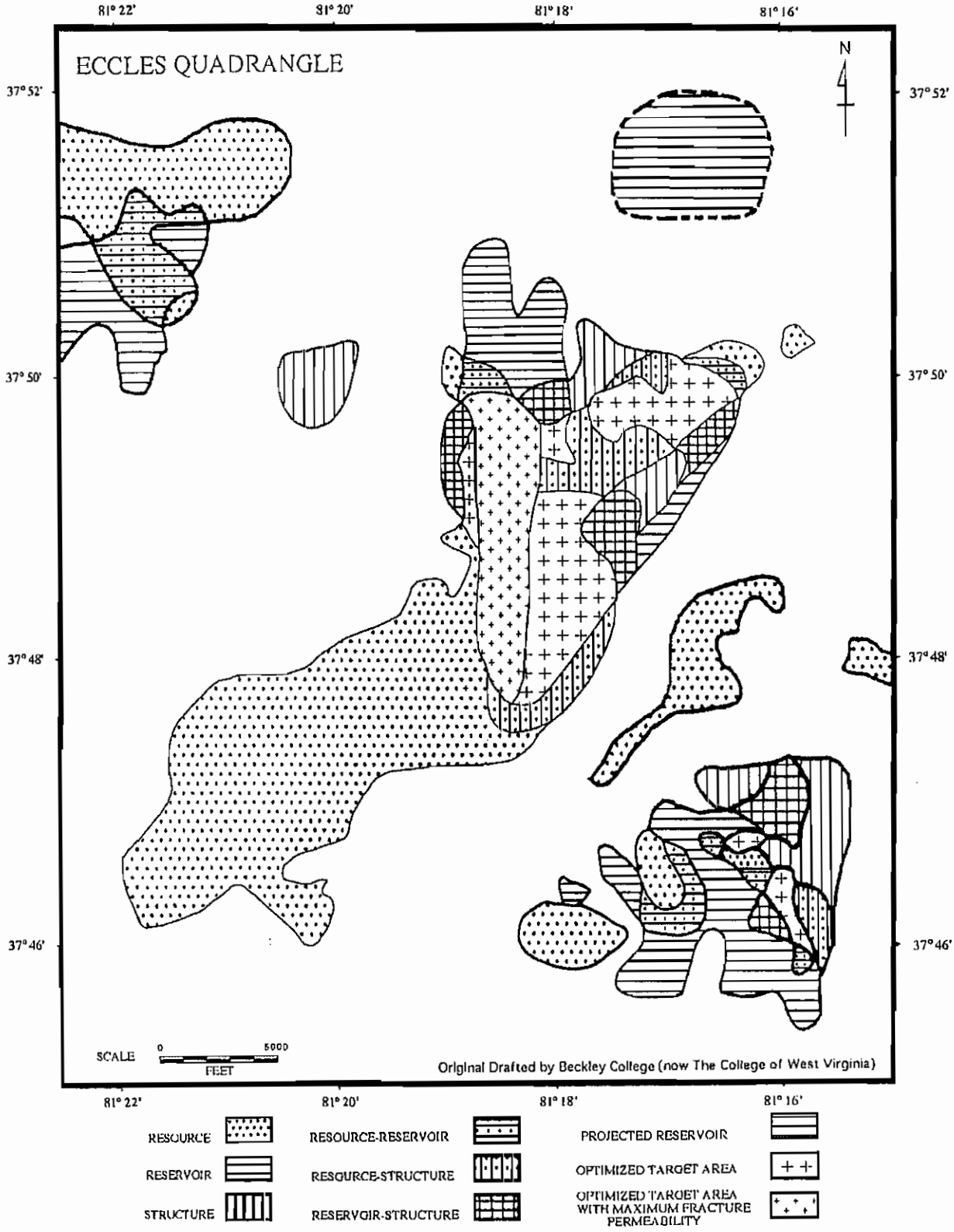
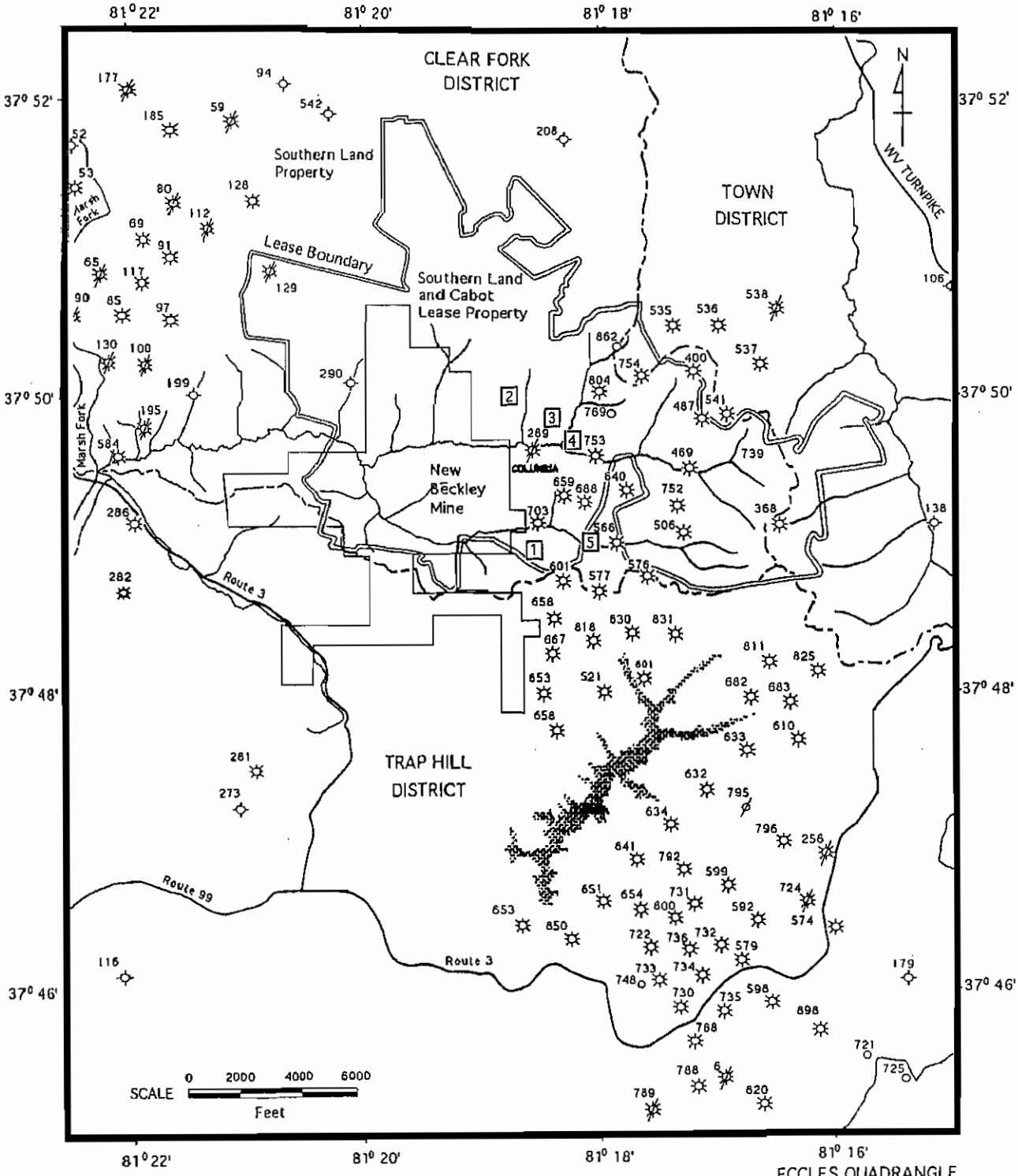



Figure 1.0.2 - Results of Intense Geologic Study of the Eccles Quadrangle Showing Areas of High Potential for Gas Production




NUMBERED SQUARES REPRESENT PROPOSED TARGET SITES FOR DRILLING

ECCLES QUADRANGLE
RALEIGH COUNTY, WV

Original Drafted by Beckley College (now The College of West Virginia)

Fig. 1.0.3 – Locations of Five Drill Sites near the Optimum Area based on Lease Ownership and Existing Well Information

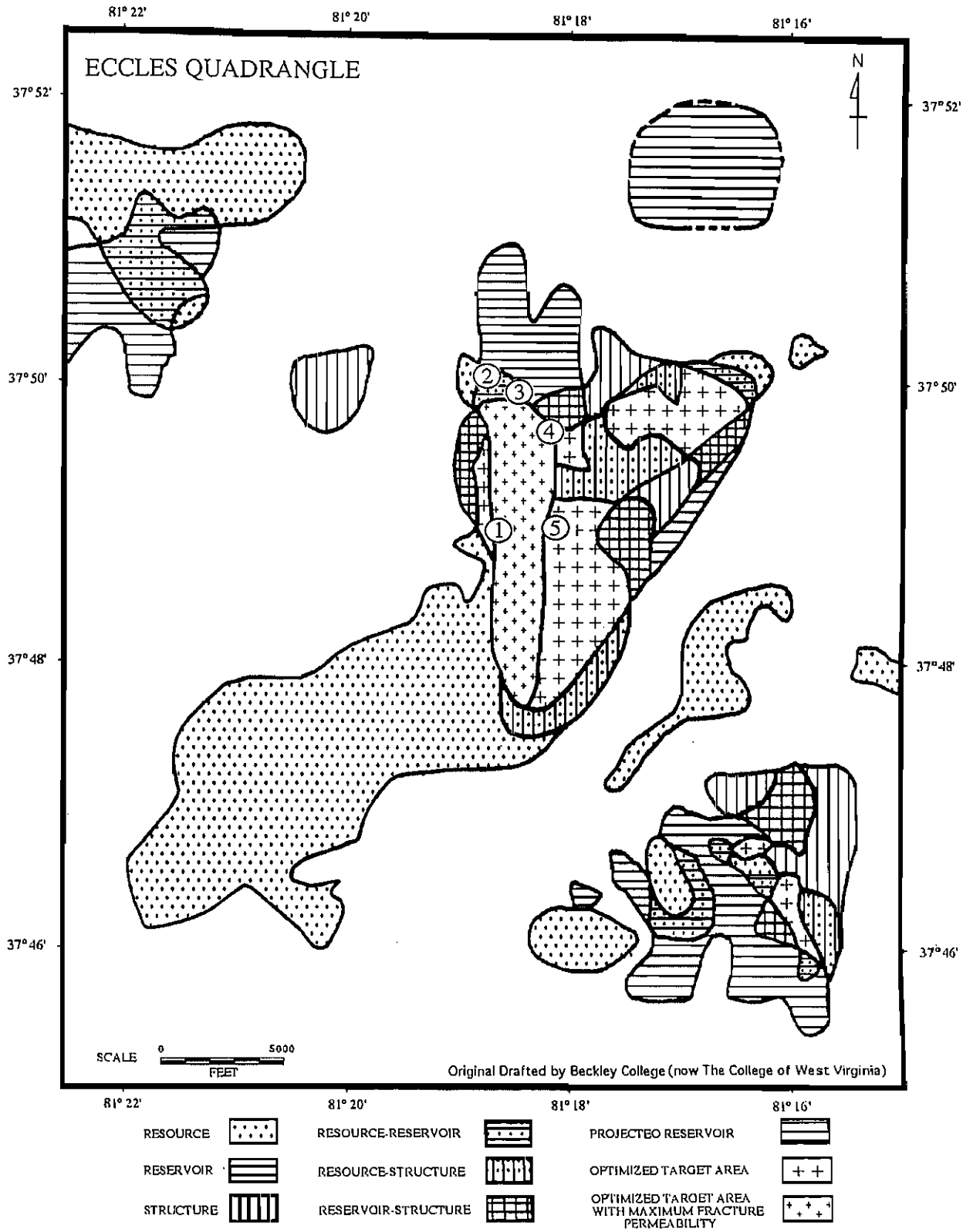



Fig. 1.0.4 - Prospective Drill Sites Overlaid on Component Optimization Map Showing Each Site to be Within or Near the Optimized Area

After the lineament study was completed, a 3-mile-long seismic line was run in-an east-west direction along Sandlick Creek. The results of the seismic mapping indicated a fault and small basement high in the area previously projected to be a high fault block by structure and thickness mapping. This confirmation of faulting gave credence to the projected areas of increased fracture permeability. Seismic data indicated that Test Well #3 (TW-3) was located over the fault zone.

In the areas around the top three sites selected, natural fractures were mapped, followed by earth resistivity profiling surveys (ERPS) across the mapped fractures. Geochemical surveys of the subsurface (at least three feet below ground level) were made for the same area to indicate the presence or absence of hydrocarbon traces in the near-surface soils. The survey revealed somewhat unusual distributions of oil and gas which appeared to be more related to topography than proximity to local, deeper deposits. Outcropping sandstones were found to have the highest concentrations of hydrocarbons, apparently having captured and retained upmigrating gas. In addition to natural gas, indications of possible oil accumulations were found and later were verified by samples from a 170-foot thick sandstone unit above the Pocahontas #4 coal seam. The oil shows were encountered at a depth of 1120 feet in sample cuttings from well TW-2. The commercial potential of the oil accumulation is not known.

The geoscience studies indicated gas resources should be found in the areas to be tested. After the geoscience studies were completed, a drilling plan for Test Well #1 (TW-1) was prepared and approved by DOE. At the same time negotiations for farmouts of leases for the locations of the wells were initiated but could not be completed for eight months (April 1991).

Drilling operations on TW-1 began on April 30, 1991, and were completed on May 7, 1991. Four thirty-foot coring runs were made to obtain samples of the Beckley and Pocahontas coals. The well was then deepened to the planned total depth of 2995 feet near the base of the Greenbrier Limestone (Big Lime). The well was logged, cased, and cemented. The well was designed for a dual completion setup, with Big Lime and Ravencliff sand to be produced from the 4-1/2" casing while the Pocahontas and Beckley coals would produce from the 8-5/8" casing.

The Big Lime was stimulated with foamed acid and tested at 230 mcfd open flow potential after 7 hours. The Ravencliff sand was foam-fraced and tested at 63 mcfd. A subsequent combined three-hour test of the well indicated a 200-mcfd gas production rate from the the two formations. The 4-1/2" casing was then removed from the well to a depth slightly below the coal levels so that the coal seams could be accessed and stimulated via the 8-5/8" casing. A specially-designed clean-water stimulation was conducted on the two coal seams. The well was swabbed to clean up water. On July 15, 1991, the coals tested 47 mcfd open flow potential after 1460 bbls of water had been swabbed from the coals, about half of the 3000 bbls injected during the frac jobs.

Approval to drill the remaining two wells was received in October, 1991, following a review of the TW-1 results by DOE. Test Well #3 (TW-3) was spudded on October 29th and was completed on November 5th. Test Well #2 (TW-2) was spudded on November 12th and was completed on November 18, 1991. Drilling operations were similar to those conducted on TW-1. All three had 8-5/8" casing set 150 feet below the Pocahontas #3 coal and 4-1/2"

casing cemented to a point approximately 200 feet above the Ravencliff sandstone. A left-right nipple was included in the 4-1/2" casing string just inside the 8-5/8" casing so that the 4-1/2" casing could be removed for access to the coals.

Logs of both wells were analyzed to select zones to be stimulated in the last two wells. Log analysis revealed that the Big Lime in TW-3 had insufficient porosity to warrant stimulation. The logs also revealed that Big Lime porosity was not as well developed in TW-2 as in TW-1; however, because of gas shows noted during drilling, four zones were selected to be acidized. The logs of the Ravencliff sandstone in TW-2 indicated good porosity and the zone was selected for a foam frac.

The Big Lime in TW-2 was acidized on January 23rd and swabbed and tested on the 24th. After swabbing on the 24th, the Big Lime tested 42 mcfd open flow potential, and after additional clean-up on the 27th, tested 54 mcfd. TW-3 was then stimulated in the Ravencliff sand on January 28th, and on January 29, 1992, the Ravencliff in TW-2 was fraced.

The Pocahontas #3 and #4 coal seams in TW-3 were stimulated on February 11, 1992 and cleanup started on the 12th.

An attempt to complete TW-2 in the coal seams was unsuccessful because the 4-1/2" casing could not be removed from the well. A review of the cement bond log run in TW-2 indicated that cement had come up to the level of the left-right nipple, apparently high enough to prevent the 4-1/2" casing from being unscrewed. Attempts were made to break the casing loose from the cement which covered the nipple by only one foot, but failed. Because of the potentially high cost to correct the situation, action was deferred until production tests could be conducted on the coals in the other two wells.

To avoid venting the gas to the atmosphere, the production test was delayed until a gas sales contract could be completed and a pipeline could be constructed and tested. To obtain a gas sales contract, gas samples were collected and tested from each formation to be produced to assure pipeline-quality gas (1000+ BTUs per cubic foot) and that no excess nitrogen remained. With a gas contract in place, a 30-day production test was initiated on July 30, 1992; however, because of TW-1's close proximity to an abandoned mine and the gas company's concern for a possible oxygen hazard, the coals in TW-1 were not allowed to be produced until August 17, when additional gas analysis revealed the methane to be oxygen-free.

During the 30-day production test, TW-1, producing gas almost entirely from the Big Lime and Ravencliff, averaged 26 mcfd for the 11 days it produced. TW-2 produced gas only from the Big Lime at an average rate of 11.3 mcfd, and TW-3 produced gas mainly from the Poca #3 and #4 coals at an average rate of 10.2 mcfd for its 20 days of production. The three wells together had a combined average production rate of 47.5 mcfd.

During the test period, water was pumped from the coals at a rate of 4 bbls/day from TW-3 and 7.3 bbls/day from TW-1. TW-1 coals were producing practically no gas (1 mcfd) as opposed to 10.2 mcfd from TW-3 coals. The literature describing coalbed methane production in other areas indicates that water may have to be pumped daily for several months before

coalbeds reach their peak gas production rate.

## 1.3 Conclusions and Recommendations

TW-1 which was drilled in the optimum area, is considered as a successful test of the validity of the exploration methodology. Multiple producing strata were encountered with strong initial open flow rates. Production test results from three coalbeds and two natural gas formations indicate the success of the methodology. Production test rates a year later were somewhat disappointing, but perhaps to be expected in a reservoir with less than 50 percent of the original reservoir pressure remaining. As an exploration methodology, the procedure works fine. The methodology also works well as a development tool to optimize well locations in a partially-depleted reservoir.

TW-2 and TW-3 were accurately characterized by the optimization map. The wells were drilled in areas exhibiting very favorable conditions for two of the three major contributors to gas production in the area. The wells have to be considered marginal producers in the Big Lime and Ravencliff formations but should be successful methane producers with continued dewatering of the coal seams.

# 2.0 INTRODUCTION

## 2.1 Background

This project was developed to test the extension of a technology developed in support of coal mine health and safety research. Roof fall prediction technology was adapted to the exploration for, and development of, natural gas and coalbed methane. In 1972, the US Bureau of Mines (USBM) developed a technique to identify, through the use of geologic analysis, areas where roof falls might occur. Bureau researchers developed the technique of picking areas where there occurred three or more geologic elements which were considered likely causative agents for roof falls. The technique now is used routinely in planning coal mining operations.

This project extended the USBM methodology methodology to the identification of potentially gas-productive areas where the correct geologic conditions and combinations of source rock, reservoir rock, and favorable structure exist. These geologic elements, and their subsets which combine to create areas of enhanced potential, are depicted graphically in Figure 2.1.1. Using this procedure in a new or developing area for gas and oil exploration, geologists would examine all the sedimentary rocks in the geologic column. To narrow the focus of the study for this project, however, only Pennsylvanian and Mississippian-age rocks down to a depth of 3000 feet were considered. Organic carbon rich shales, coals and limestones were considered as source rocks, while sandstones, limestones, and coals were considered as potential reservoir rocks.

By applying the methodology developed in Phase I of the project, five well sites were selected and rank-ordered based on projected reserves. These well sites were the focus of Phase II activities which culminated in the drilling, completing, and testing of three wells to verify the concept.

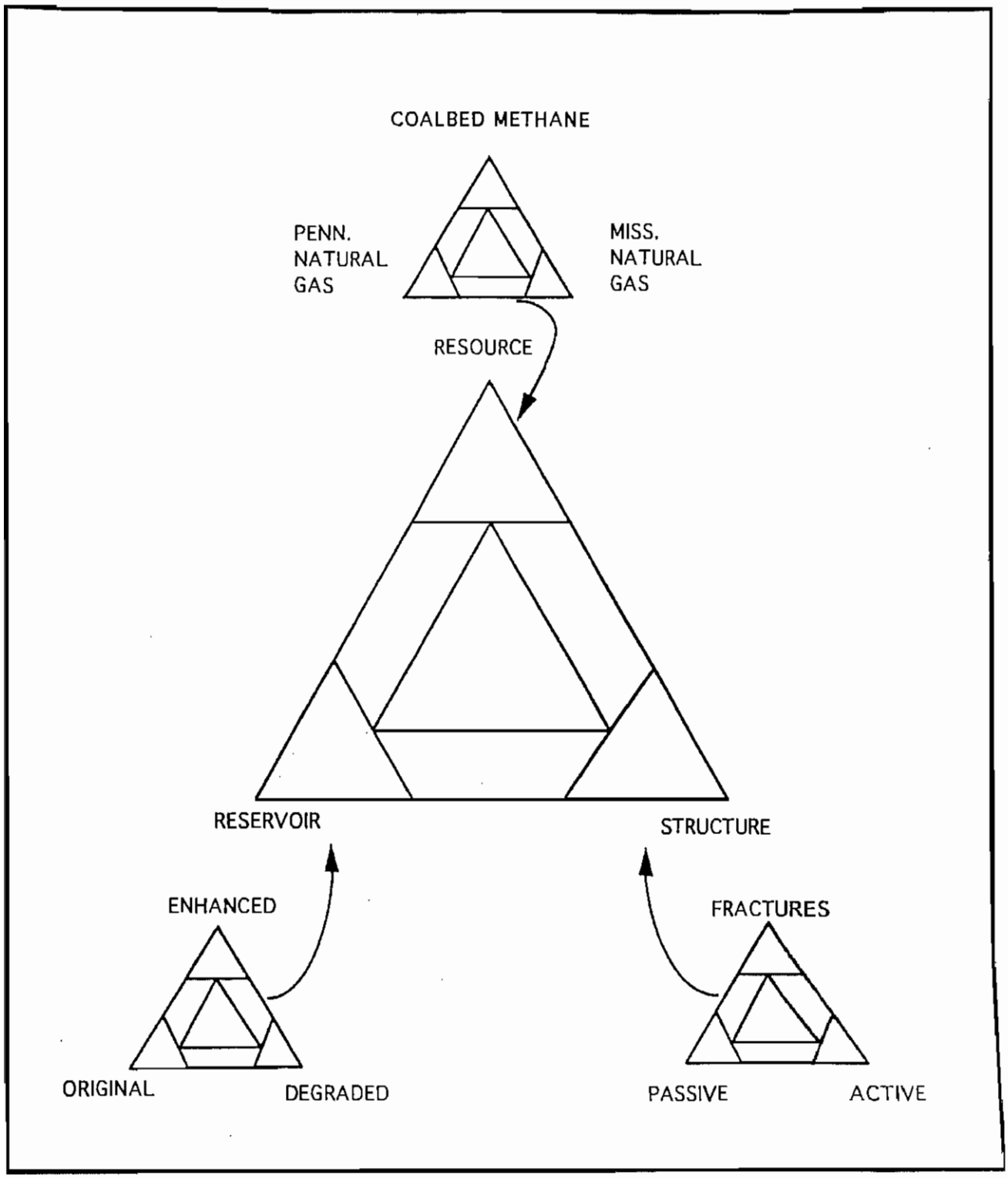



Figure 2.1.1 - Graphical depiction of geologic conditions and combinations of source rock, reservoir rock, and favorable structure which combine to create areas of enhanced potential

## 2.2 Technical Approach

The five locations were rank-ordered based on regional geologic investigations and more closely examined through auxiliary geoscience studies of areas surrounding the locations. Remote sensing to map natural fracture zones, earth-profiling resistivity surveys to validate fracture zones, geochemical survey lines, and a seismic line were run to provide additional insight into the likelihood of finding gas and a structure to trap it.

After confirmation of the locations, leases were to be obtained suitable to support three wells. The wells were to be drilled and tested in numerical order. After the first well was completed and tested, the results were to be reviewed to determine if they warranted the drilling of the remaining two test wells. Upon successful completion of all wells, a pipeline was to be laid and the gas sold in normal commercial markets.

# 3.0 PHASE I ACTIVITIES SUMMARY

Phase I activities were directed at compiling resource and production data for Raleigh County, West Virginia (See Figure 3.0.1), quantifying the natural gas resources present, developing analog models of the productive reservoirs in the area, and examining all of the factors which may have combined to yield commercial gas production. This information was then used to model and to project where additional commercial wells could be drilled. The results of Phase I studies were presented in the topical report: "A Novel Geotechnical / Geostatistical Approach for Exploration and Production of Natural Gas from Multiple Geologic Strata" (Ref. #1). This report details the procedures developed to evaluate a region, area, prospective well sites, and optimized drilling locations. The following discussion summarizes those activities.

## 3.1 Geology and Energy Data Collection

A key aspect of the project was the development of a database for the study area which included information on both geology and gas production. The primary source for the geology database was the West Virginia Geological and Economic Survey (WVGES). Information relative to gas production was obtained from the State Oil and Gas Conservation Commission computerized database maintained by WVGES and from individual oil and gas operators.

Well logs were obtained for select wells in crucial areas to assist in reservoir identification and in the formulation of reservoir analog types. Well completion information, initial potential, and pressure data were also obtained from state well completion records (e. g., Form OG-10).

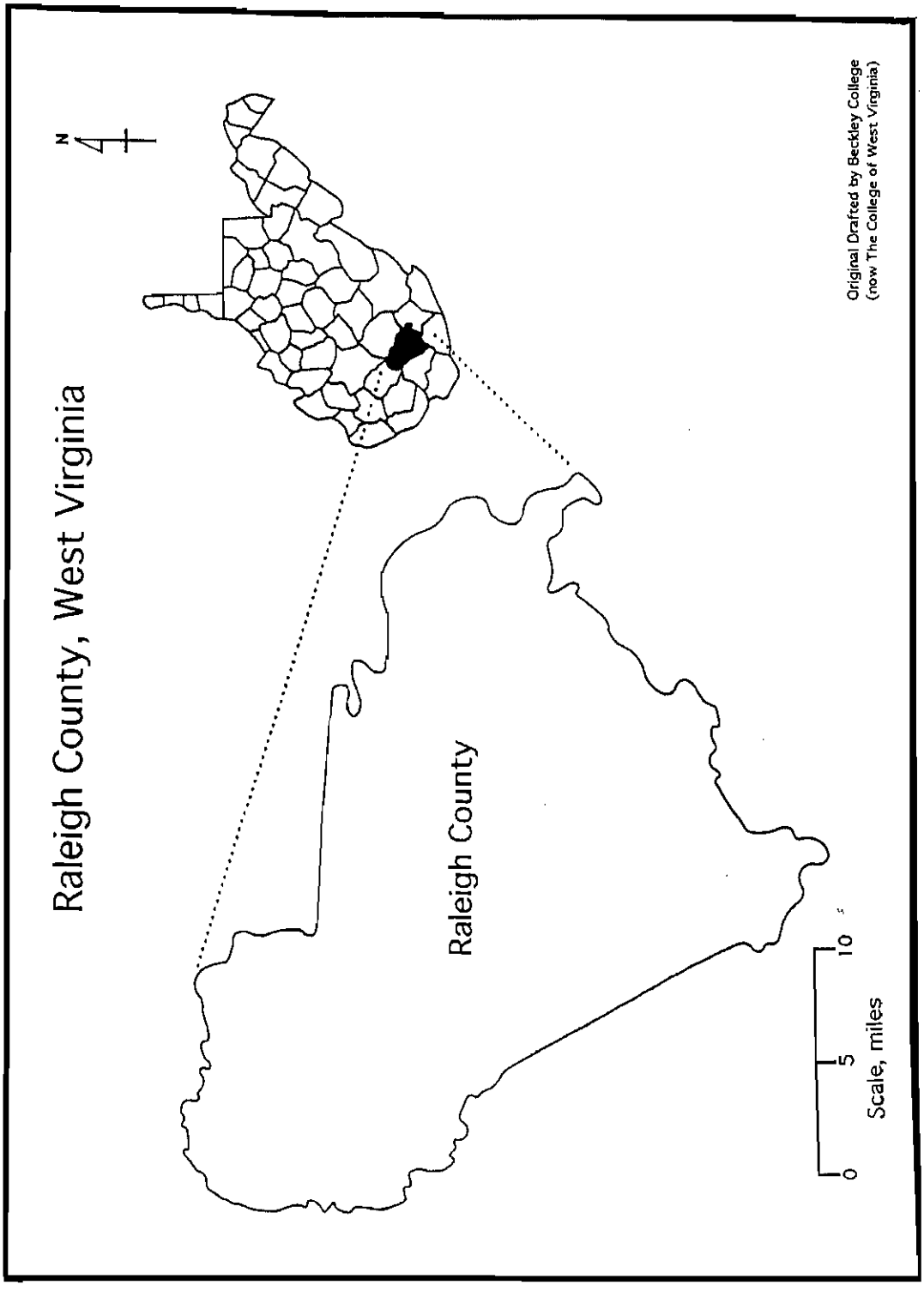



Figure 3.0.1 – Location of Raleigh County, West Virginia

### 3.1.1 Database Development

The names of the WVGES computer files utilized in the study and their primary function were as follows:

CLO (Completions, Locations, and Ownership Data) - This file contained the basic data necessary to identify the wells, by permit number, with additional data like operator number, county and district, field, and quadrangle. Location information was provided in the form of longitude and latitude. Surface and mineral owner names were provided, as were surface datum and total depth along with completion method. The natural and after-stimulation flows and pressures/times were detailed, as was current production status;

Strat (Stratigraphic Data) - The strat file included information identification and depth below "datum" as well as the datum value and datum type. The "thickness" was also listed, although the nature or source of this number was not coded. "Thickness" may have been a measured electric log value or a driller's estimate;

PayShow (Formation Depth and Show Data) - This file listed all oil or gas shows encountered, along with top and bottom of the show interval and volume before and after stimulation, as reported on the state's well completion report forms;

Water - The water file contained a listing of the shallow and deep water-producing formations which had been reported to the WVGES, and a water-quality classification code as fresh or salt water, when known;

Plugging - This file included all the plugging data available to the WVGES since 1929, when this data file was first created.

Production - The production file contained monthly and annual oil and gas well production figures and days-in-line numbers as reported to State agencies and collected by WVGES. These data varied in completeness by area and by operator, many wells having data for some years and no data on other years. A code was provided to identify the source of the data.

The data were collated and manipulated in numerous ways to produce various displays and to create structure and isopach maps for the major reserve formations.

### 3.1.2 Natural Gas Data Collection, Collation, and Analysis

Natural gas production data were collected from the previously cited sources on a well-by-well basis. The data were used to develop decline curves, and gas simulation models were used to project cumulative production to the economic limit of each well. Average spacing between wells and the drainage area for each well were calculated from map data. Where there was insufficient data for volumetric calculations, the original gas in place for each well was estimated by dividing the predicted economically recoverable gas by the generally accepted recovery factor of 65% for gas reservoirs in West Virginia. By dividing the original gas in place for each well by the well's drainage area, the original gas-in-place per unit of area was calculated, expressed as millions of cubic feet per acre.

### 3.1.3 Coalbed Methane Data Collection, Collation, and Analysis

Available coal data sets and maps for the four quadrangle study area were obtained from the WVGES. The major coals, the Beckley and Pocahontas #3 seams, were mapped for structure, thickness, and coalbed methane originally in place. These figures were then converted and recontoured as maps of the methane-content-per-acre-foot across the study area. Finally, the maps were modified to show the effects of the lost methane in the mined areas to produce plots of the coals' methane-remaining-after-mining.

The coalbed methane resource was estimated by collecting core data on coal thickness and mapping coal volume in acre-feet. Data on the gas content per ton of coal was collected from a number of sources including the U.S. Geological Survey, WVGES, U.S. Bureau of Mines, and private industry core analysis data. Using a value of 100 lbs per cubic foot of coal as the approximate density of the Beckley and Pocahontas coals, a total of 2,178 short tons of coal per acre-foot of seam was calculated. By multiplying this number by the thickness of coal measured for each seam, the total number of tons of coal per acre was calculated. This number was then multiplied by the gas content per ton to determine the resource in place which was reported as millions of cubic feet of gas per acre.

## 3.2 Definition of Target Areas

Although the geologic and production database contained data for all of Raleigh County, in-depth studies of gas resources, reservoir properties, and geologic structure were conducted in an area defined by four topographic quadrangles (Beckley, Lester, Crab Orchard, and Eccles; Figure 3.2.1). The four-quadrangle area was too large for detailed studies, so it was decided to select one of the four for the detailed study. Comparative analyses of the four quadrangles were conducted to narrow the focus to a single quadrangle by examining the number of producing formations, their thicknesses, original gas in place, area available for development, and the geologic structure in each of the four original quadrangles. Both coalbed methane and natural gas targets were considered in the comparative analysis.

The primary coal targets for the study were the Beckley and Pocahontas #3 seams. Although the Lester Quadrangle originally had the largest area of minable coals, it also was the most extensively mined, causing much of the methane resource to be dissipated. The thicker coals also have been mined extensively in the Beckley Quadrangle area, and mining has been moderately extensive in the Crab Orchard Quadrangle. The key coals also were too shallow for good methane production in much of the Beckley and Crab Orchard Quadrangle areas, where these coals actually outcrop.

The conventional natural gas resources were also compared. The Lester Quadrangle was eliminated as a target area due to limited remaining drilling locations because of extensive development, mostly with older wells lacking adequate data for the computerized analysis process. The Beckley and Crab Orchard Quadrangles had scattered, older, exploratory wells, but no significant older production that could be identified from the study data base, and the key deeper producing formations, including the important Big Lime, appeared to be non-gas-

productive. A recent drilling boom for gas was stimulated, however, in the Beckley and Crab Orchard areas by Wrightstone's report on the Ravencliff "F" Channel (Refs. 5 and 6).

Within the Eccles Quadrangle, several formations produced gas, including the Ravencliff, possibly the slightly deeper Maxton, the still deeper Big Lime, and the Weir Sandstone, which was beyond the depth limits considered in the project.

It was concluded that the greatest potential for shallow conventional natural gas resource development lay in areas with both Pennsylvanian and Mississippian reserves. This helped eliminate the Beckley and Crab Orchard Quadrangles where coalbed methane potential was also limited. For both conventional natural gas and coalbed methane, the Eccles Quadrangle offered the best opportunities for testing the exploration techniques. Because it had the largest remaining coalbed methane resources and the best opportunities for shallow conventional gas resource development, the Eccles Quadrangle was selected for more detailed analyses.

## 3.3 Analysis of Geologic and Production Data

The computerized data bases and other information were manipulated extensively in conducting the detailed geologic and engineering analyses.

### 3.3.1 Analysis of Structural Data

Information available from the WVGES was entered into the database and computer-plotted, then extensively hand-modified, to produce structure, single-formation isopach, and large-interval isopach maps to decipher the structural history of the study area.

#### 3.3.1.1 General Geologic Setting

The Eccles Quadrangle has several small folds overprinted on generally northwest dipping sediments. Pennsylvanian-age sandstones, shales, siltstones, limestones, and coals are exposed at the surface. Relief is rugged, with hills generally rising between four- and five-hundred feet above deeply incised stream valleys. Resistant sandstone cliffs are common in the area.

#### 3.3.1.2 Regional Structure and Tectonic History

The study area is in a structurally uncomplicated section of southern West Virginia on the midportion of the Central West Virginia Massif. This "massif" was a stable Basement block that remained high with relatively little internal deformation during the late Precambrian and early Paleozoic eras, the period when the basic framework of the Appalachian Basin was being established. As extensional features formed to each side, the Raleigh County massif remained relatively high and in place, tilting gently to the north.

Although there is minimal relief on the present-day Basement surface, the Central West Virginia Massif is theoretically composed of highly disturbed, badly broken crust. It was part of the old Grenville Continent that had been thoroughly shattered during the Grenville Orogeny.

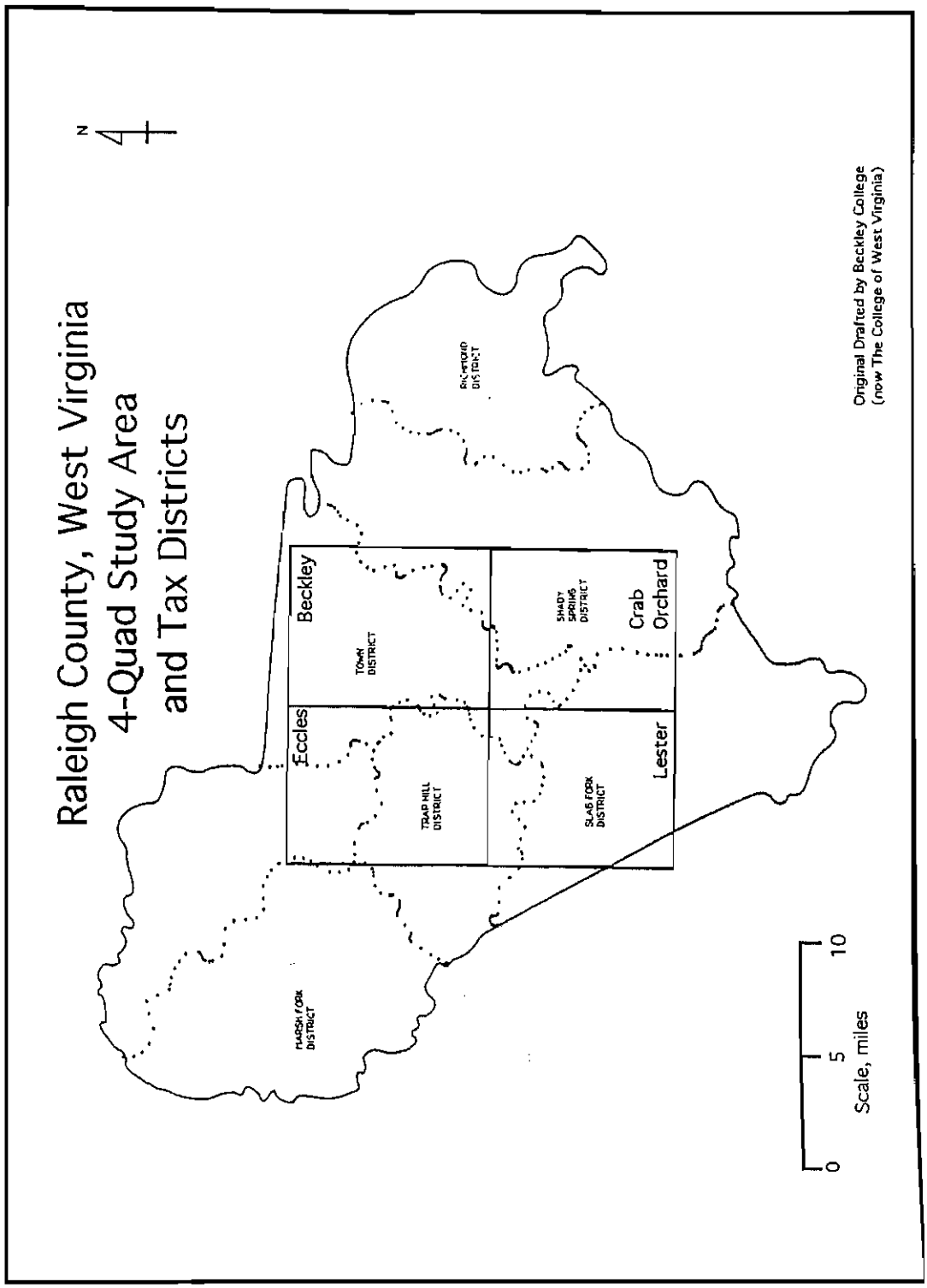



Figure 3.2.1 - Four topographic quadrangles selected for in-depth analysis of gas resources, reservoir properties, and geologic structure

Over the great span of geologic time from the Paleozoic to the present, movements on the Grenville breaks have been recurrent, and occasionally may have been frequent. The Rome Trough opening indicates that a great tensional episode occurred several hundred million years after the Grenville orogeny. The Taconic, Acadian and Alleghenian collisions along the East Coast probably produced compression along these features, elevating the hanging wall (east) block slightly. These subtle movements seem to have controlled drainage features or current patterns locally in the Appalachian Basin at various times during the Paleozoic and could have caused a stacking of drainage courses or shoreline standstills in the same areas at different periods.

Most of the Grenvillian features in this area tend to run North-South, parallel to the Grenville structure zone. Extensive North-South oriented drainage east of the Grenville Front through much of Southern West Virginia testifies to the persistence and effectiveness of the Grenvillian-related fracturing. Many of the faults have moved recently enough to have fractured the shallower beds, exerting control on modern drainage. In addition, a significant number of oil and natural gas fields in West Virginia, Pennsylvania, and Ohio run essentially North-South, often with sharp western boundaries, presumably along Grenville-related fracture trends.

Despite the lack of seismic data for this project, the presence of a Grenville-oriented Basement block in the study area can be inferred through several lines of evidence. A narrow positive structural feature appears to run nearly North-South from the southwestern portion of the Lester Quadrangle through the central area of the Eccles Quadrangle.

Most of the Paleozoic tectonic history of Raleigh County was very quiet. There was little obvious structural disturbance created locally during the opening of the Rome Trough or during the Taconic or Acadian Orogenies. The most significant change was coarsening of the sediment influx during the orogenic events. The Basement block may have been reactivated during these orogenies, but no major movements are detectable.

3.3.1.3 Structure Mapping

Structure and isopach maps were prepared from the Berea formation up, showing a series of structural highs, breaks in slope, and thins on the isopach maps across the Basement block. Lithologic studies show facies changes in the same area.

These shallow data imply the existence of a persistent positive area through the Lester and Eccles Quadrangles throughout much of the Paleozoic. The location coincides with the area of closure in the Silurian and Lower Devonian targets.

There are hints in the data base that another active Basement block may cut along the east edge of the Beckley and Crab Orchard maps; however, this cannot be stated as a certainty without additional study and an expanded data base to the east.

Figure 3.3.1 shows the structure at the Berea level for all four study area quadrangles. Structure contours indicate a regional dip to the northwest complicated by the influence of the Basement high. A depression shows up to the east of the high. The Berea structure contours run southwest-northeast until they reach the Basement high, at which point they bend to the north, then cut across the high and drop to the south into the low, east of the positive block.

The Big Lime structure, Figure 3.3.2, resembles that at the Berea level. The same domes show up, although the shape and high point on the northern dome on the Eccles Quadrangle has shifted somewhat and the crinkled pattern around Irish Lick Knob is quite different. The sag between the two domes on the Eccles map is marked by a synclinal axis.

The Big Lime lithology indicates there was shoaling above the Basement block during Big Lime time, further indicating that this structural feature was active at the time of Big Lime deposition.

Figure 3.3.3 shows the Ravencliff structure for the four maps. This structure is similar to that for the deeper Big Lime and Berea formations.

Detailed coal structure maps were prepared for the Beckley and Eccles Quadrangles. Figure 3.3.4 shows the Pocahontas #3 Coal Structure.

The data on the Pocahontas Coal are limited. The depth of the seam has generally inhibited plans to mine this seam on the Eccles Quadrangle. The control is much better on the shallower Beckley Coal which is shown in Figure 3.3.5.

The Beckley Coal also shows the obvious regional strike, but the contours contort in the eastern portion of the Eccles Quadrangle over the Basement high and along the eastern edge of the Beckley Quadrangle where the existence of a second Basement high can be inferred.

3.3.1.4 Trend Surface Analysis of Structure Mapping

Production from the Big Lime in West Virginia has typically been explained as coming from limestones laid down in very shallow water. In one model, limestone porosity is developed at the time of deposition in shoal areas. At shallow depths near wave base, the energy level is higher and lime muds can be rolled up into oolite pellets with porosity development between grains, or within the rolled up ooids. In a second model, reservoir porosity may be developed with the build up of organic mats or low reefal growths. In a third model, the shallow-water limestones were later dolomitized with the development of significant, sometimes cavernous, porosity.

Big Lime production appears to be especially dependent upon structural features which were highs, or shoal areas, at the time of deposition. To assist in deciphering the location of these original Big Lime shoals, a trend surface analysis was performed on the Big Lime structural data for the Eccles Quadrangle. The Big Lime structure map for the Eccles Quadrangle was used as a base for the study.

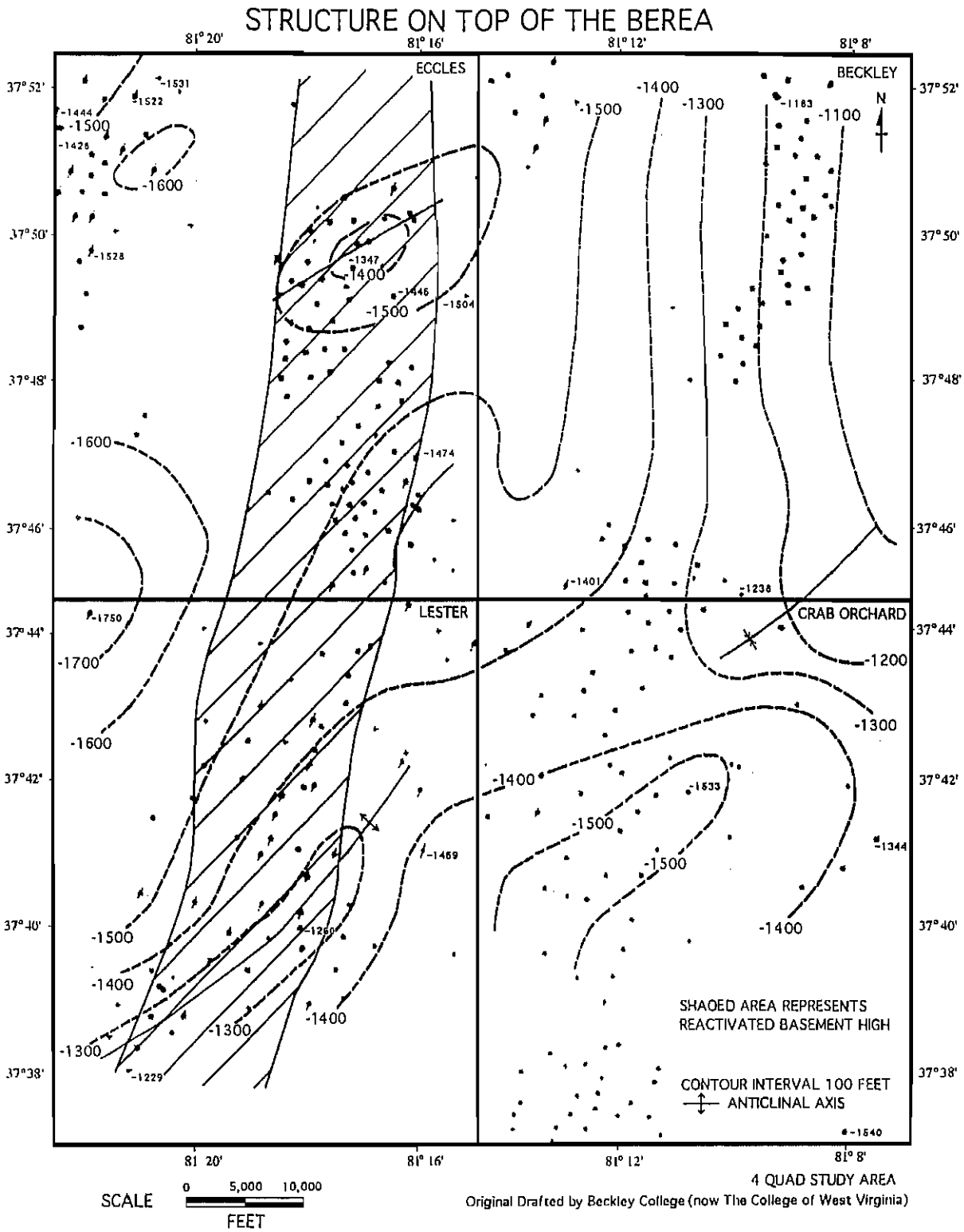



Figure 3.3.1 - Structural Contours on the Berea Sandstone Showing a Northwest Regional Dip Influenced by a Basement high.

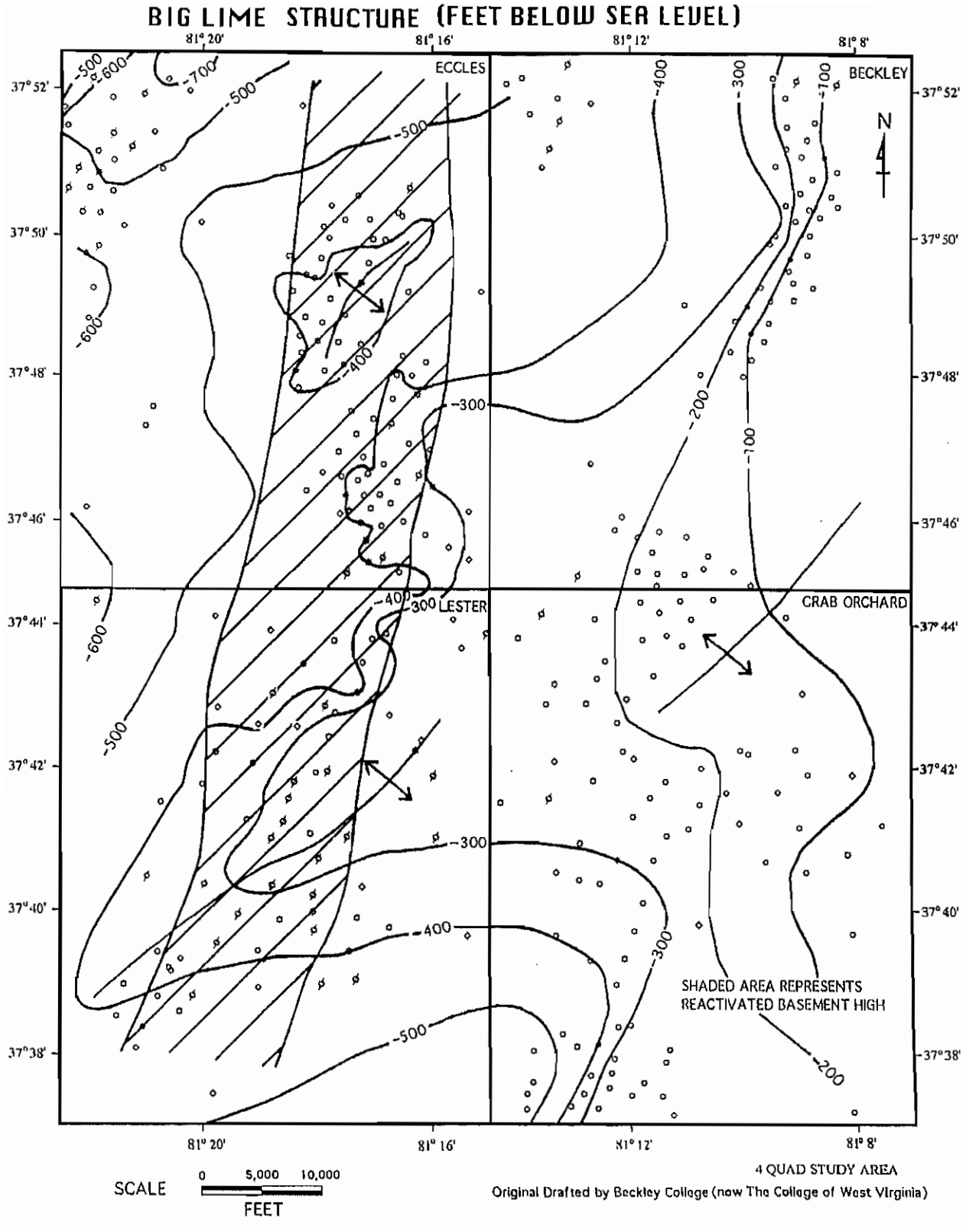



Figure 3.3.2 – Structure on the Big Lime Indicating Similarities to the Berea Structure

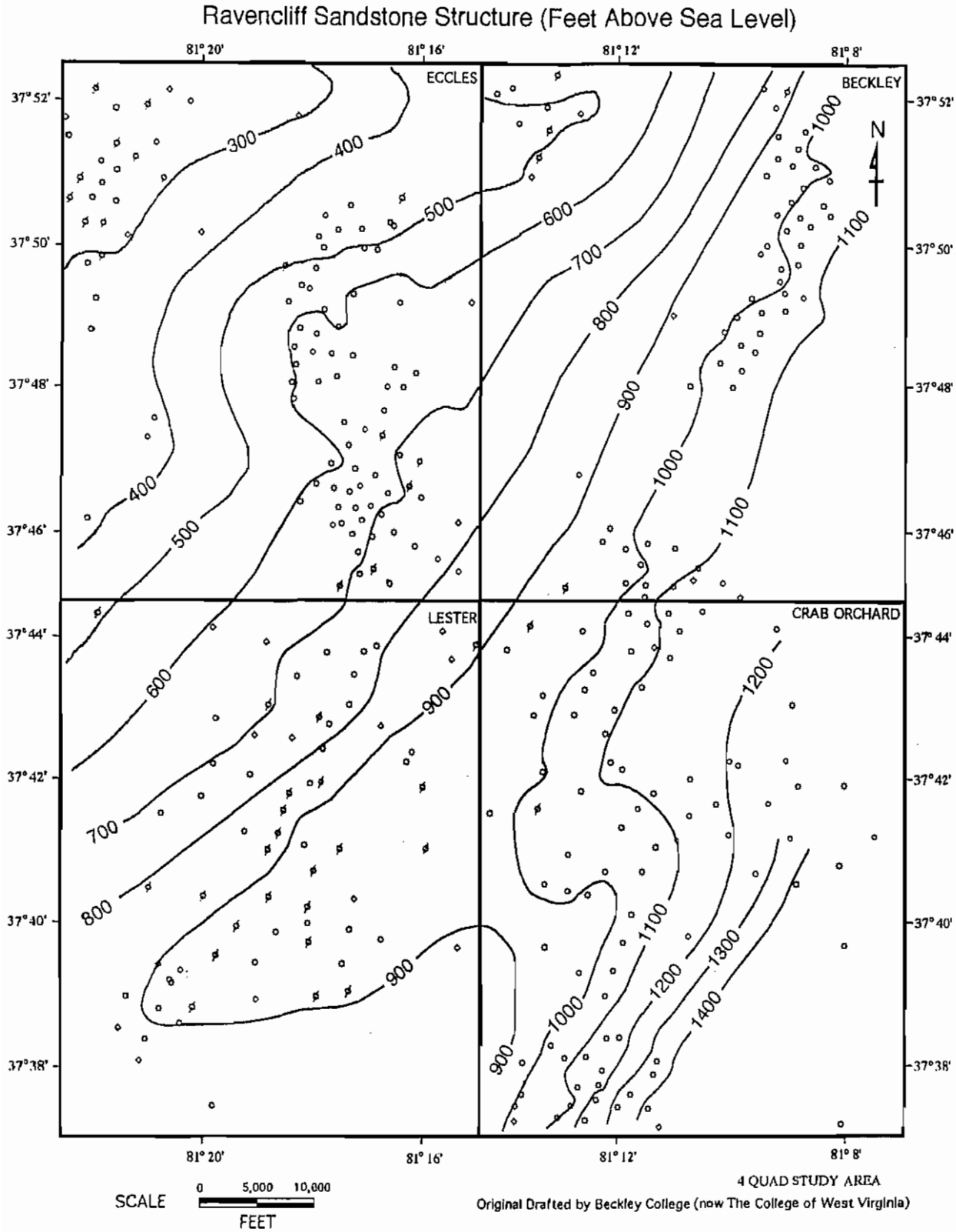



Figure 3.3.3 - Structure on the Ravencliff Sandstone Showing Similar Structure to that of the Deeper Big Lime and Berea formations.

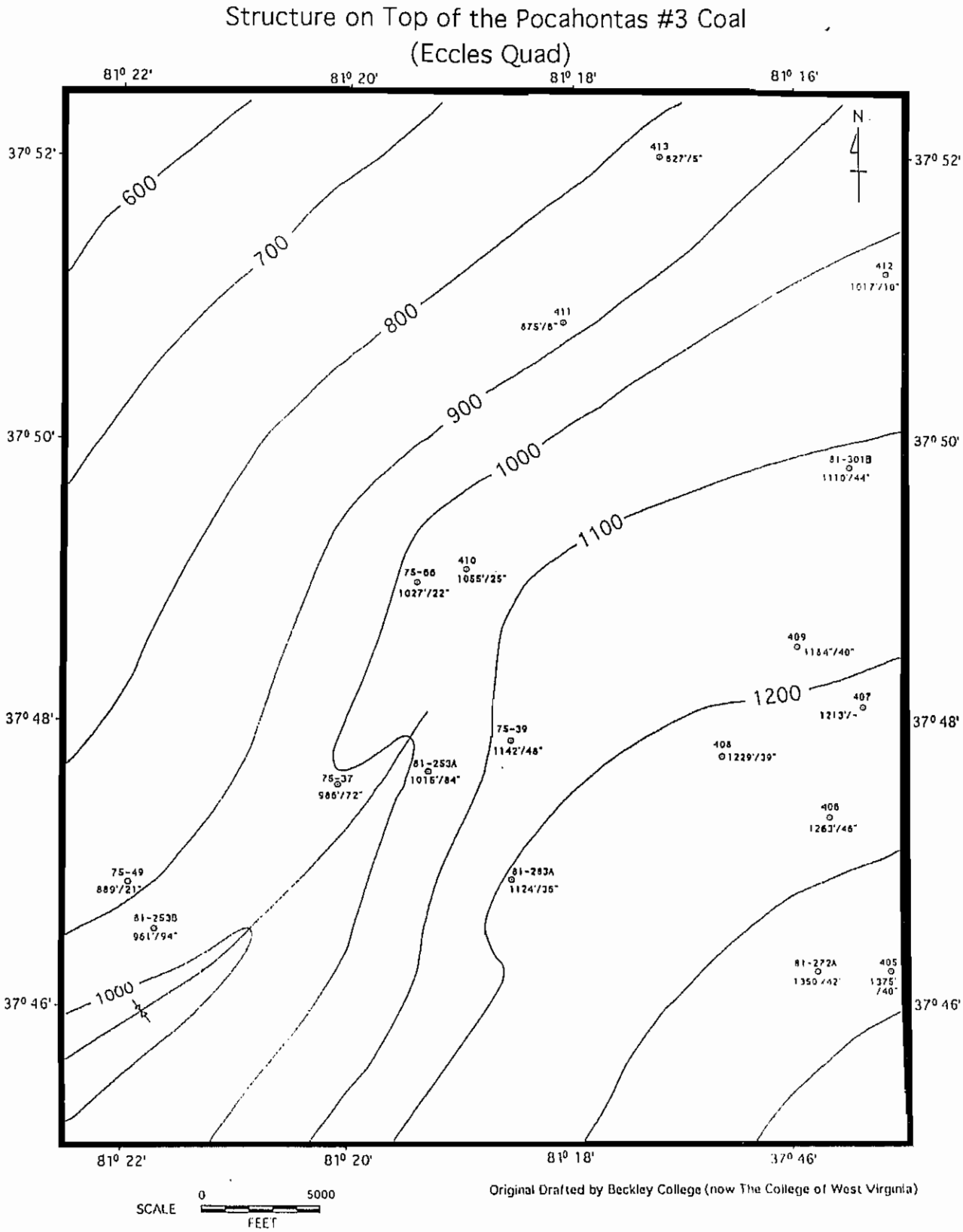



Figure 3.3.4 - Structure on the Pocahontas #3 Coal

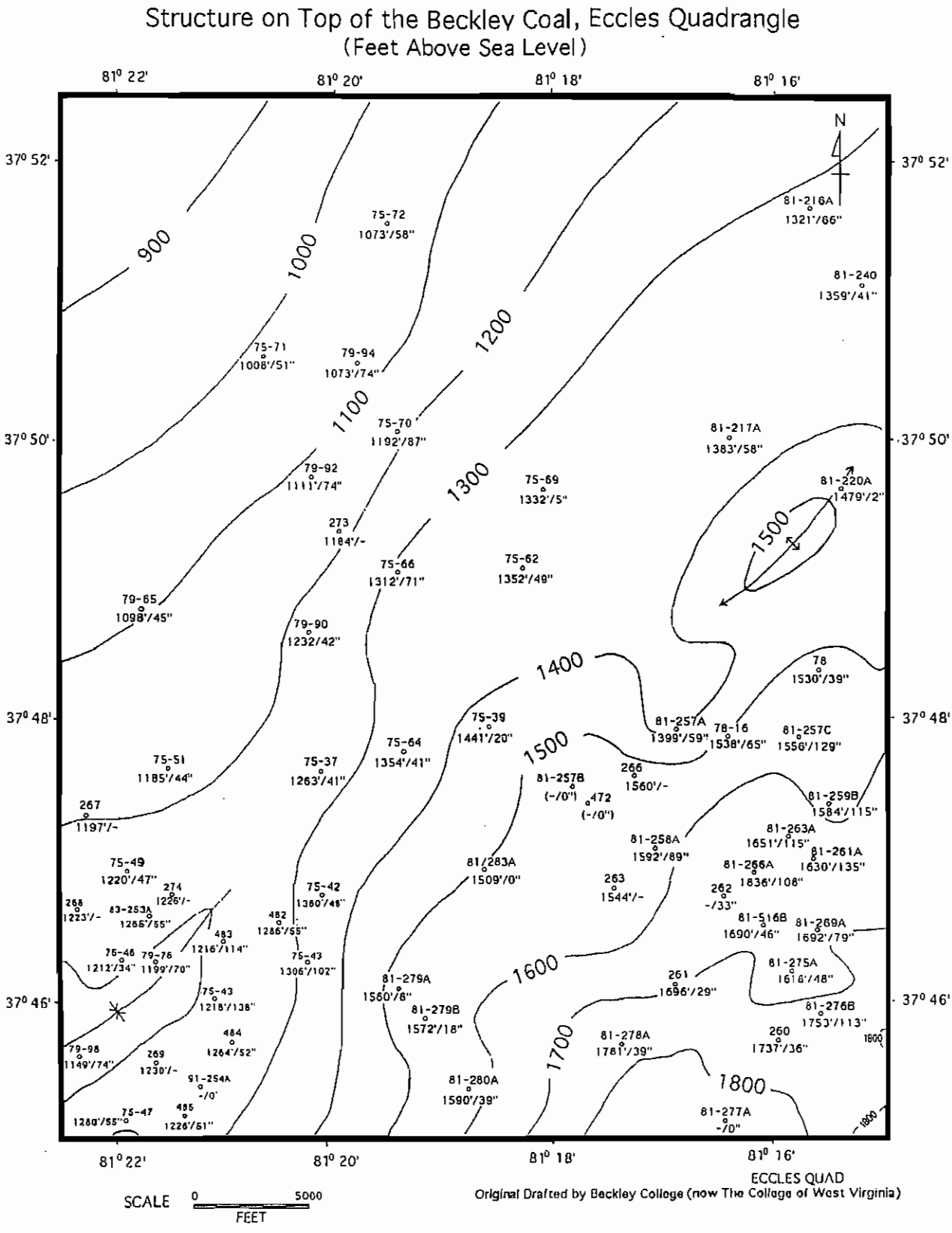



Figure 3.3.5 - Structure on the Beckley Coal

Figure 3.3.6 shows the Big Lime Positive Residual Anomaly Map, a graphic representation of the recurrently tectonically active areas on the Eccles Quadrangle. Isolated spots have values almost two hundred feet above the regional trend. Most of the northern dome is in excess of one hundred feet above the regional surface. The southern dome, by contrast, rarely reaches 100 feet above the trend surface. This helps to explain the greater productivity on the northern feature where the water was apparently shallower and the oolites would have been tossed around with greater intensity. Some of the most productive wells on the southern dome are located at the north edge of the high where the highest point on the dome occurs.

3.3.1.5 Analysis of Structural Control on Gas Production

As illustrated by Figure 3.3.7, many subelements contribute to the influence that structure can have on oil or gas production. Several units in this area like the Tuscarora, Oriskany, and Big Lime produce on top of paleohighs. Successful prospecting for these units involves a good understanding of structure.Structure at the Berea and Weir levels shows two highs at an angle to the Alleghenian-age folds in approximately the same position as the Tuscarora and Oriskany highs. Large-interval isopachs between these formations and shallower beds with extensive control, confirm that these areas were positive during Upper Devonian time. Deeper basinal areas lie along the 81°15′ longitude line which divides the Eccles and Beckley and the Lester and Crab Orchard Quadrangles. The Berea has not been productive in the study area, and the Weir production is too limited to relate to structure.

3.3.2 Analysis of Reservoir Isopach Data

Lithologic and isopach data provide clues to periods when Grenvillian-age Basement blocks moved and to when they were quiescent. The evidence strongly implies that activity was episodic and that the area was not under continuous compression.

Lacking seismic evidence, much of the data on early movements of the Basement is based on isopach evidence. Wells penetrating the formations below the Big Lime were too sparse to allow the formations to be isopached meaningfully, other than to identify the general area of the Basement high.

Isopach information implies that the high persisted for some period of time after Greenbrier/Big Lime deposition ended. The feature continued to have a subtle expression, but the Little Lime and Pencil Cave units both appear to thin across this structure

Isopach maps for the Maxton family of units (the Upper Maxton, Maxton proper, and Lower Maxton) are difficult to decipher, due to extensive correlation problems and misidentification of the three units in the data base. It is not obvious if the three units are affected by the deeper structures.

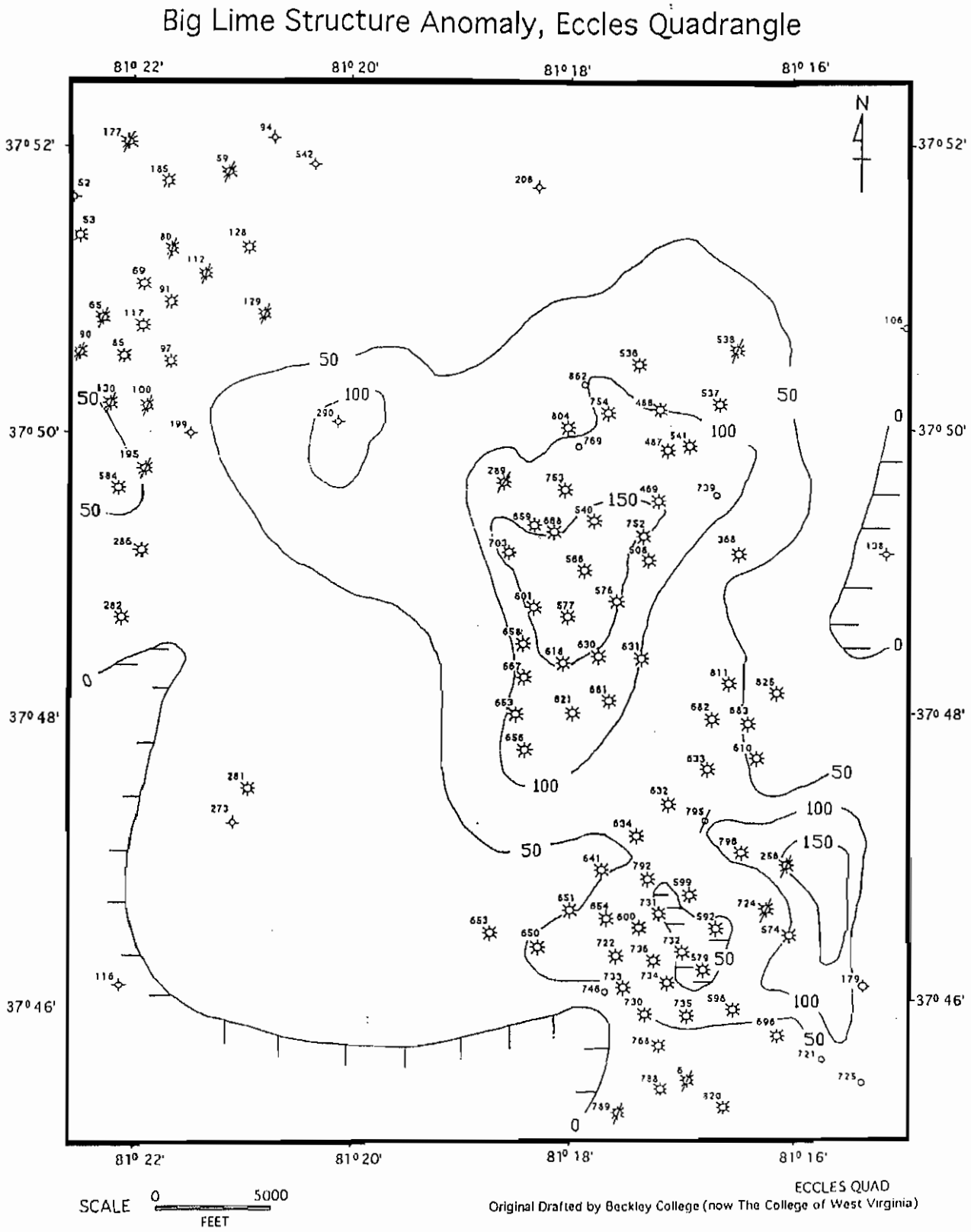



Figure 3.3.6 - Big Lime Positive Residual Anomaly Map Illustrating Recurrently Tectonically Active Areas

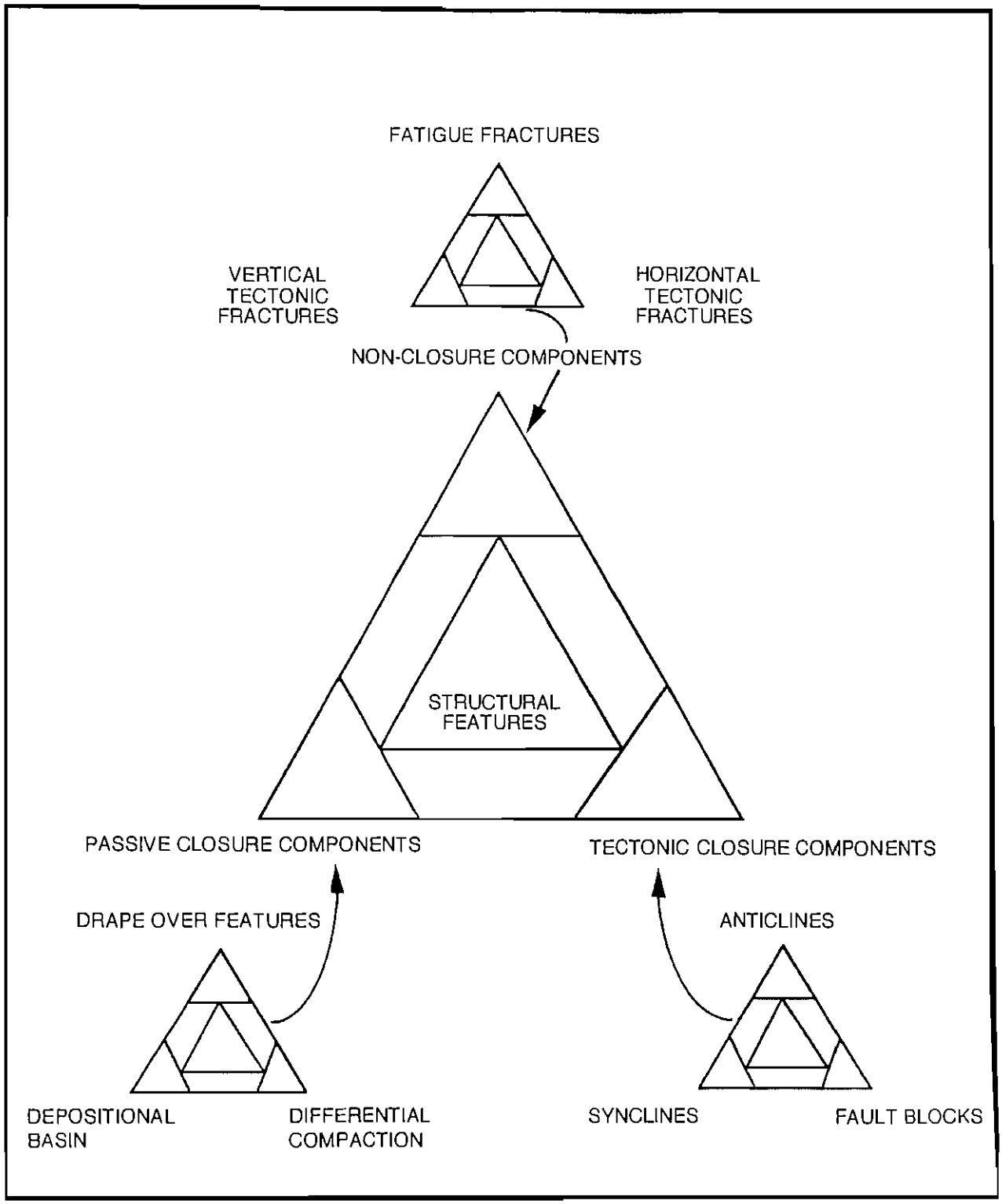



Figure 3.3.7 – Illustration of Subelements Contributing to the Structural Influence on Oil or Gas Production

By Ravencliff time, the Basement seems to have stabilized. The Ravencliff fluvial channels follow essentially straight plans from the north directly through the study area without any deviation as they cross the mapped quadrangles. The largest river channel in the mapped area, Wrightstone's "D" Channel shows no twisting, turning, or broadening as it reaches the area of the positive Basement high. An isopach map (Figure 3.3.8) does not indicate any thinning over the central area of the maps.

The Beckley Coal isopach thins to zero over the area of the Basement, Tuscarora, Oriskany, and Big Lime highs. The Pocahontas #3 Coal has not been cored in this critical area, but it too may pinch out across the high. It appears that the basins on the flanks of the Big Lime high had been a flat floodplain during Ravencliff time, but then dropped again, becoming the focus for major, rapidly subsiding swamps during the Carboniferous coal period.

### 3.3.3 Reservoir Lithology

The Berea is a wide-spread sand that sits atop an unconformity surface at the top of the Devonian shale section. The Berea is productive across much of West Virginia, but has not even had a show of gas or oil reported on the Quadrangles studied for this report. It is a fine-to very fine-grained, tightly- cemented sandstone.

The Weir units are another widespread series of sandstones that are productive across much of West Virginia. In the eastern counties, they mark part of the great deltaic complex (Boswell and Jewell, Ref.2) that extended out to the west from the Acadian-age mountains that were rising in Maryland and Virginia. Similar deltas lay to the north and south, fronting mountains from Pennsylvania on into New England and from the Carolinas to the south.

Although the Pocono "Big Injun" Sandstone is a major reservoir unit across much of West Virginia, it is not gas productive in this portion of Raleigh County. No shows have been reported in the Big Injun in any of these Quadrangles.

The Chesterian-Age Greenbrier section, locally, and in this document referred to by the drillers' name "Big Lime," is the deepest unit in the Beckley area with significant production. There is a very close correlation between the pattern of wells with gas in the Big Lime and the Natural Gas Reserves map for the Eccles Quadrangle. All of the best wells on the map have produced from the Big Lime. Comparing the Reserve maps with the show and producing patterns for the shallower formations demonstrates that no other formation is consistently productive on the Eccles Quadrangle. On this quadrangle, drilling an exceptional well seems to require good to excellent results in the Greenbrier Big Lime.

The Beckley Coal thickness decreases from about twelve feet to zero in just a few thousand feet at the edge of the high, implying a relatively rapid subsidence of the swampy areas or a rise of the high block as the coal accumulated.

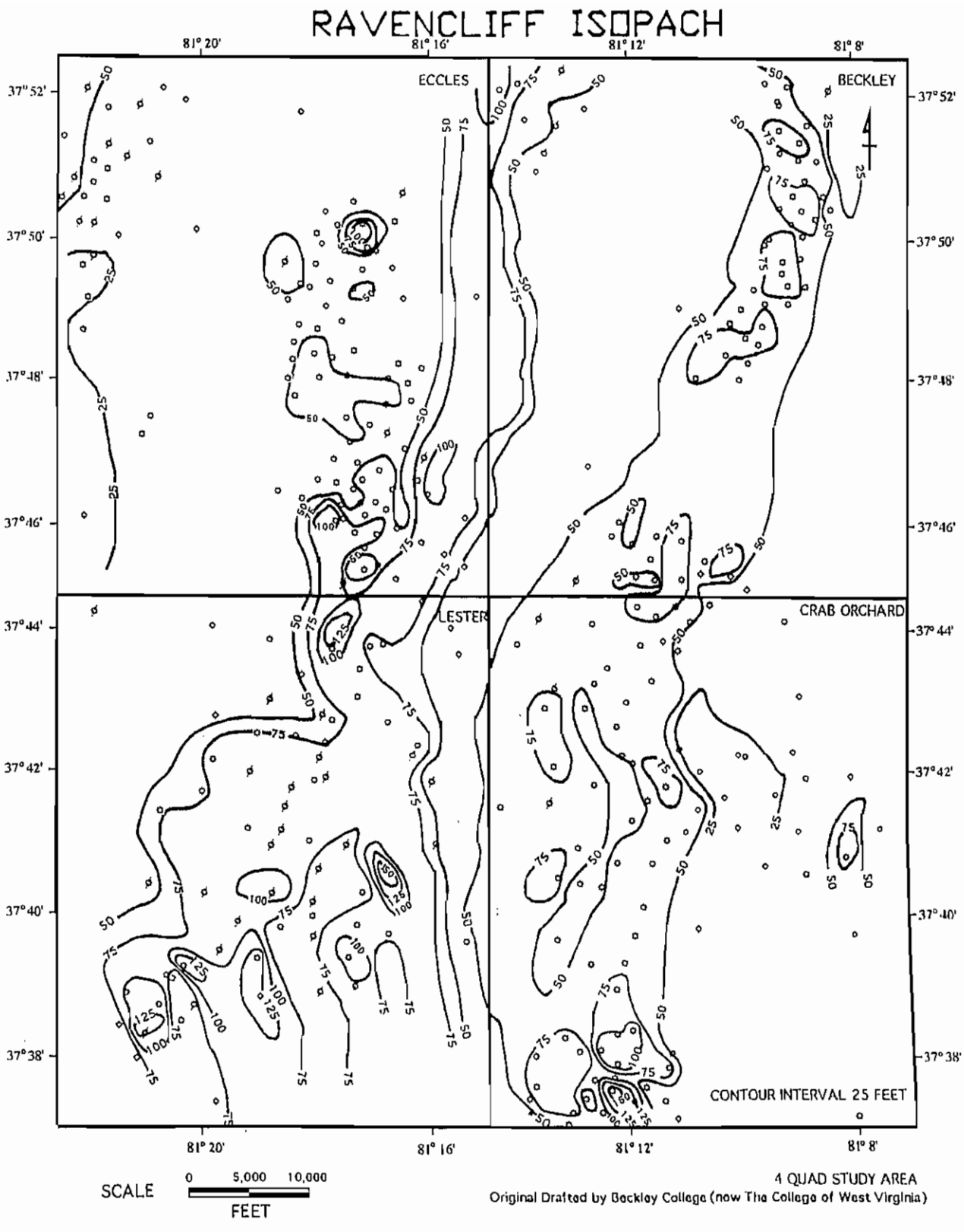



Figure 3.3.8 - Isopach Map of the Ravencliff Sandstone Showing Relatively Straight Fluvial Channels Running North-South Through the Study Area

The Maxton (also "Maxon") sediments are a mix of small, localized sand bodies within a mass of shales and silts. They were deposited when the sea that had been covering Raleigh County during Big Lime and Little Lime time was finally overwhelmed by an influx of sediments from the east. A deltaic complex spread across the county during Maxton time.

The Maxton is generally divided into three main units; the Upper Maxton, the Maxton proper, and the Lower Maxton unit. This simple classification system only hints at the complexity of sand lenses and pods, and names have often been misapplied in Raleigh County. Different names frequently have been assigned to a single sand body in adjacent wells. The "Lower Maxton" name has not been as extensively utilized in Raleigh County, therefore, it is not involved in as many errors.

The Ravencliff Sandstone has been reported on in detail by Wrightstone (Refs. 5,6) and others (Kamm and Heald, Ref. 2). These works established that much of southern West Virginia was a river floodplain during Ravencliff time. A long, sinuous channel system entered the study area near the northeastern corner of the Beckley Quadrangle and flowed to the south through what is now the town of Beckley. Just southwest of Beckley, the river forked or shifted through time with two courses having been preserved. This Ravencliff channel includes sandy deposits which generally range from 60 to 80 feet in thickness and around 6,000 to 8,000 feet in width.

### 3.3.4 Analysis of Resource Production Data

Production data were obtained as part of the computerized data file from the WVGES. The production data obtained was limited to monthly production reported to the WVGES from wells in Raleigh County. This information was woefully incomplete. For a few newer wells, complete production histories were available, but for many holes, including for all wells drilled prior to 1979, data were incomplete.

A detailed analysis of the geology and production data for the Big Lime, Maxton Sands, Ravencliff, coalbed methane, and other shallow sands, is included in Section 3.4 of the Phase I, Volume II Report.

The production data from the WVGES "Production" computerized files were combined with data gathered by The College of West Virginia personnel from industry sources to give an expanded set of completion and production numbers for the Eccles Quadrangle. The resulting information was computer processed to derive production data for the preparation of maps.

Contour maps of natural open flow, rock pressure, total reserves and remaining reserves, were developed using available data. For a more detailed analysis, please refer to Section 3.4 of the Phase I, Volume II Report.

## 3.4 Location of High Probability Drill Sites

The optimization technique, as defined in this program, focused on identifying areas where the highest number of favorable factors would exist for each of the potential target formations.

Once models were developed for each of the reservoirs in the known productive areas, it was possible to project where similar features might exist in undrilled areas. Maps were drafted which presented the probability of finding the various sets of resource, reservoir, and structural conditions in adjacent areas for each target formation. The optimized areas for potential test wells were those with a high probability for encountering multiple pays.

### 3.4.1 Development of Component Maps

Structure maps were prepared for almost twenty units, with the following being the most important and informative: Beckley Coal, Pocahontas #3 Coal, Ravencliff Sandstone, Greenbrier "Big Lime" Limestone, and Berea Sandstone. Trend surface positive residual anomaly maps were prepared for the Ravencliff Sandstone and the Greenbrier Limestone (see Figure 3.3.6). These two were combined to identify areas where the structure component was optimum.

Component optimization maps for the Resource and Reservoir elements were prepared in a similar manner. The Optimized Combined Resource Map for the coalbed methane and the conventional natural gas is presented in Figure 3.4.1. The optimized map identifies all the areas with more than 8 MMcf/acre of combined resource.

The Optimized Reservoir Map was prepared by identifying the areas of original primary and secondary Ravencliff and Big Lime reservoirs and eliminating the areas with degraded, destroyed, or wet potential and combining the results on remaining-reservoir maps. Figure 3.4.2 shows the map developed for the Ravencliff Sandstone. Methods of preparing each element component map is detailed in Volume II.

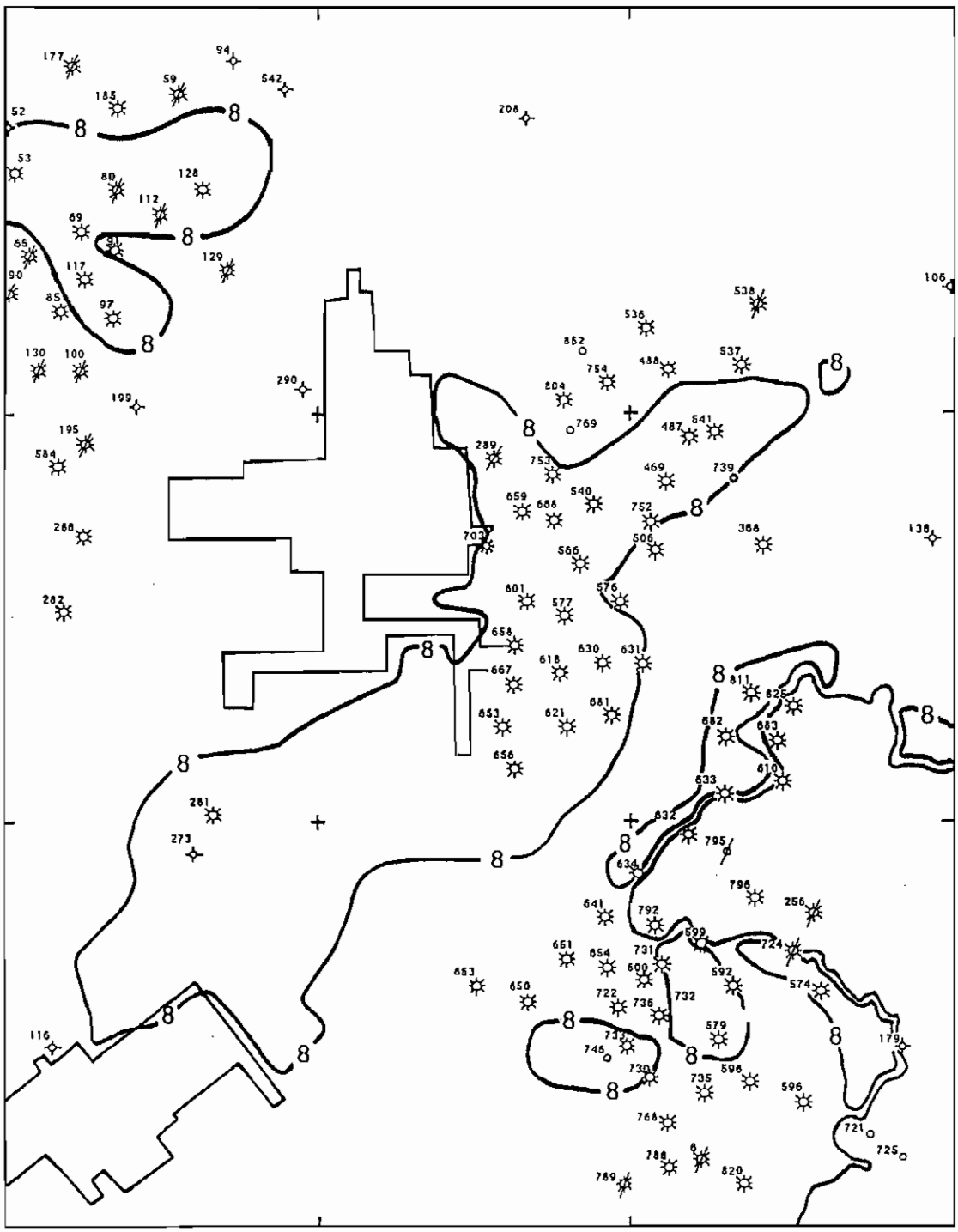
### 3.4.2 Summary Component Optimization Map

The final Optimization Map was prepared by combining all three component maps. The code to the patterns is given in Figure 3.4.3. Areas affected by one or any combination of two or by all three elements can be distinguished by a distinctive pattern. A large area North of Stevens Lake has the best potential for a positive effect from all three elements, and, in fact, has been penetrated by a number of the best natural gas wells on the map. This target zone had not been completely developed, and it was possible to select a test well location with potential for good conventional natural gas and coalbed methane production.

### 3.4.3 Site Selection Process

Verification test wells were to be completed as part of this project. The objective was to drill wells which would develop the maximum amount of natural gas and methane resource in a areas having favorable structural and good flow capacity. There were restrictions on the test well location, requiring the wells to be at least 700 feet from any coal mining operations to insure good production from the coal seams and 1200 feet from any producing gas wells to ensure adequate reservoir pressure. Three optimized sites were selected and leased for drilling to be undertaken in Phase II of the project.

OPTIMUM COMBINED GAS RESOURCE, mmcf/ac



ECCLES QUAD
Original Drafted by Beckley College (now The College of West Virginia)

Figure 3.4.1 - Optimized Combined Resource Map for Coalbed Methane and Conventional Natural Gas in the Study Area

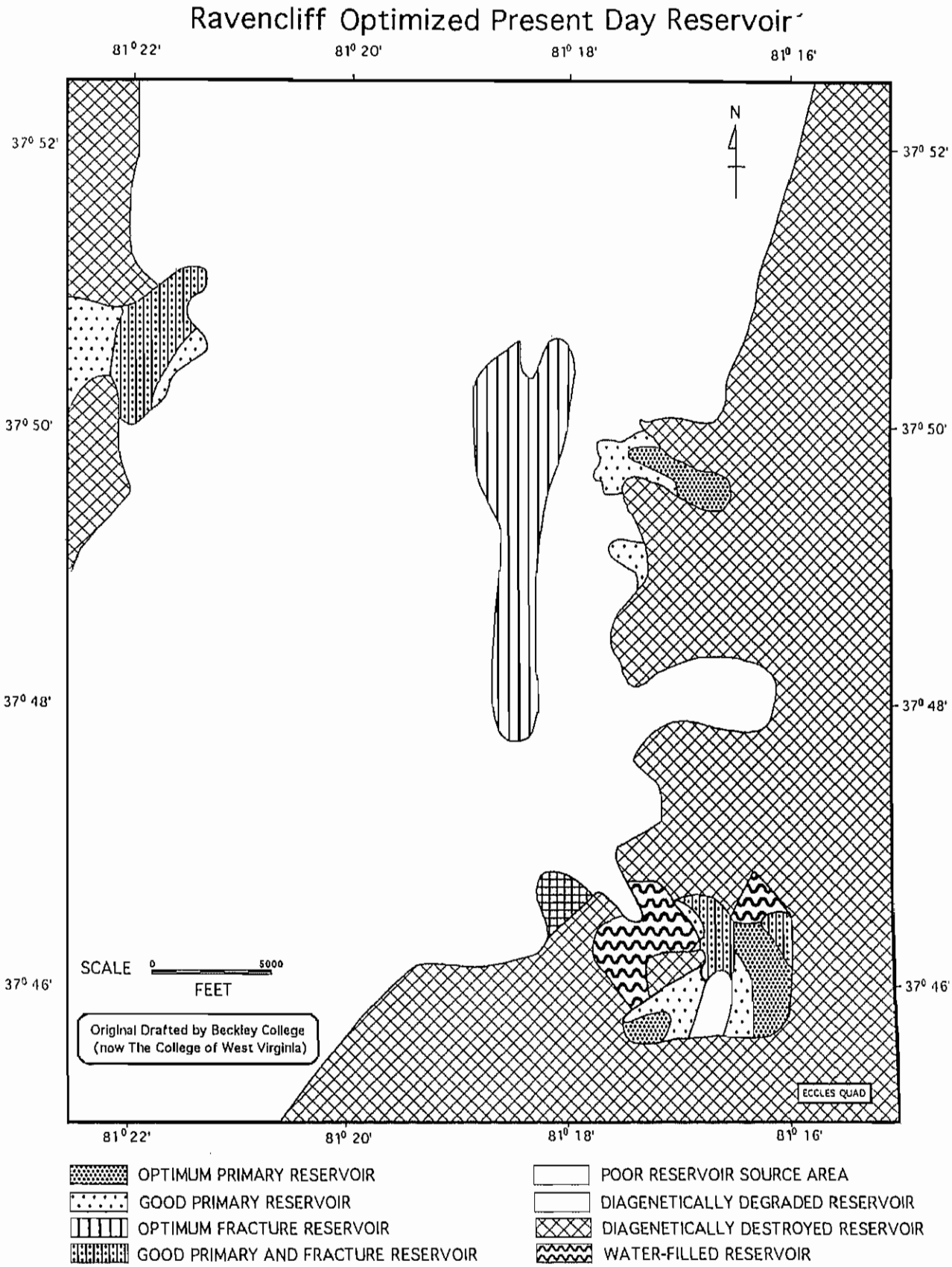



Figure 3.4.2 - Optimized Reservoir Map of Present-day Ravencliff Reservoir Conditions

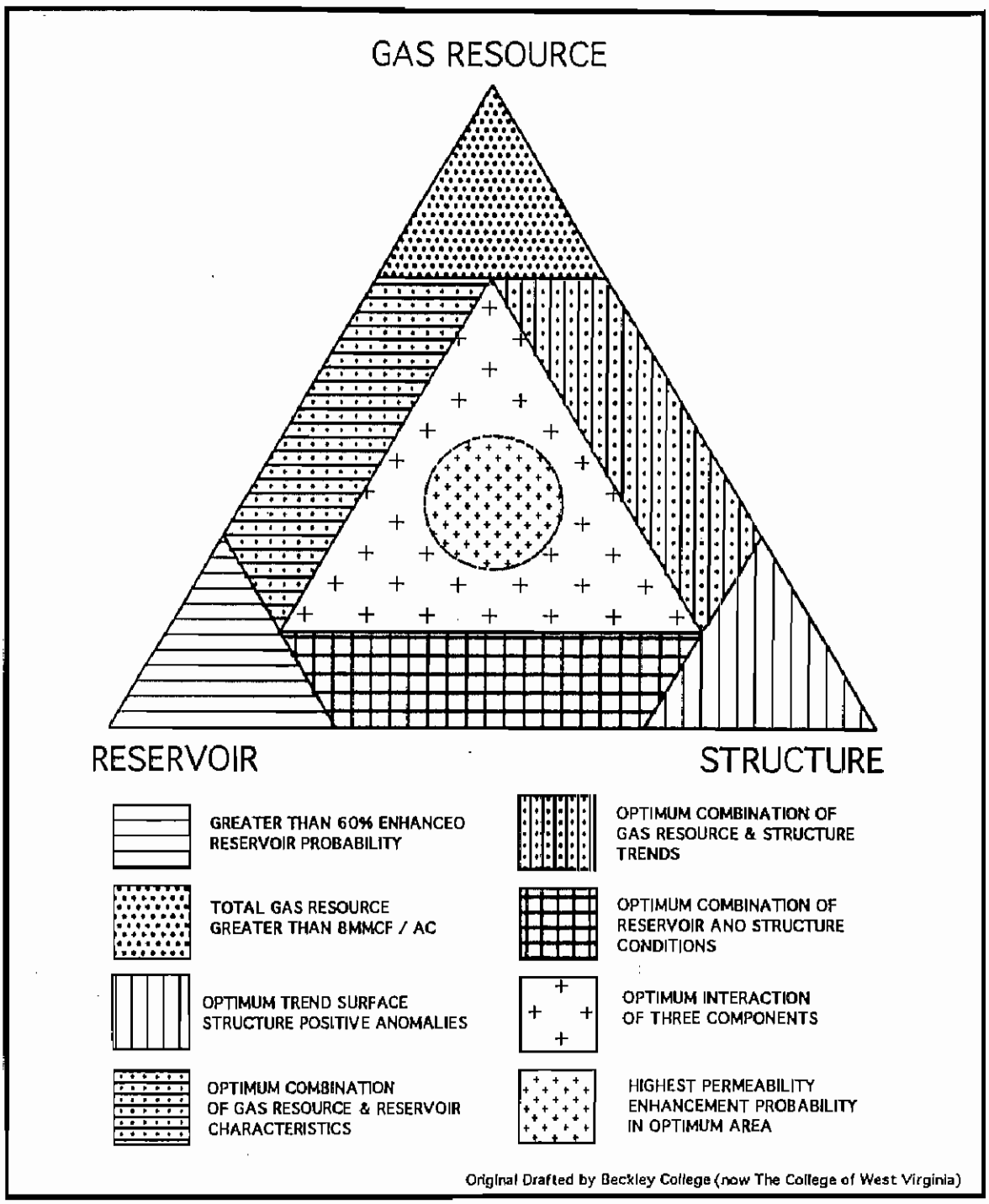



Figure 3.4.3 - Component Optimization Elements and Pattern Codes

## 3.5 Economic Assessment of Energy Extraction Optimization Techniques

The overall economics of different development scenarios were evaluated to identify a range of possible outcomes. Two methods were used to evaluate reserves and the initial-gas-in-place (IGIP). First, thirty-year reserves were estimated using a decline curve analysis, based on available production data. The second method used volumetrics to estimate reserves, based on porosity footage and saturation values from well logs. The techniques and results are detailed in Section 6.0, Volume II, of the Phase I Topical Report (Ref. 1).

### 3.5.1 Projecting Economics

Engineering models were used to predict the reserves and to estimate the cumulative production-to-economic-limit for the existing wells in the study areas.

A resource map, showing the IGIP for the Big Lime, Ravencliff and Coals, combined, was generated. Based on this map, this amount of producible gas at each of the proposed sites was determined, and the economics of the selected sites projected.

The resource analysis indicated that the methane from the coalbeds should contribute significantly to the productivity of these wells.

### 3.5.2 Comparison of Current Completion Techniques and the Multi-Strata Approach

Almost all of the modern wells on the Beckley and Crab Orchard Quadrangles have been drilled through the Ravencliff Sand, and been tested in more than one formation. Significant economic production on these quadrangles, nevertheless, has been limited almost exclusively to the Ravencliff "F" Channel. There is little production deeper than the Ravencliff in either of these areas. There are few true multi-strata wells on these quadrangles, due to a lack of economic quantities of gas so far discovered below the Ravencliff.

On the Eccles and Lester Quadrangles, the "D" Channel Ravencliff sand is much less productive than the "F" Channel, while the Big Lime frequently has good reserves on top of the Basement high block. No other units are consistently productive over large areas on these maps.

To be an economic producer, a well on the Eccles or Lester Quadrangle needs to encounter an exceptional Big Lime reservoir or to be completed in multiple zones, including all formations showing potential signs of natural gas. The multiple stage completion techniques currently being used in this area have not included any production from coal seams.

Even with the multiple completions that are common on the Eccles Quadrangle, several wells there have had total combined projected reserves of less than 10 mmcf and many more have under 100 mmcf of projected reserves. Such wells will never pay back their drilling costs.

To increase the potential economic return, this project is designed to formulate a drilling plan and well completion design that will add significant quantities of economically attractive methane to the total resource base at marginal increases in cost.

Implementation of the Multi-Strata concept utilizes a standard well completion for the deeper, conventional gas horizons along with methane recovery from shallower coalbeds via the casing annulus. Dewatering of the coal was accomplished using a small-diameter tubing string and pump inserted in the annulus. The natural gas and methane are metered separately, prior to blending the two into a pipeline-quality mix. The local methane was found to be high-quality and does not present heating value problems in a blend. In fact, after frac-treatment nitrogenwas recovered, the methane could be sold into the pipeline without blending.

### 3.5.3 Completion Equipment and Procedures

The coalbed methane and conventional natural gas is produced separately via independent casing and/or tubing strings. The coalbed methane is produced through the 8-5/8" casing and is measured using an orifice meter prior to its entering the common pipeline system. Deeper natural gas is produced via 4-1/2" casing with a 1.9" OD tubing system. This gas is also metered prior to entering the common pipeline using a second orifice meter. The orifice meters are sized on the basis of open flow tests and/or pressure build-up tests.

The initial coalbed reservoir pressures were sufficient to produce into one of the local pipeline gathering systems; however, coalbed pressures will ultimately become so low that it will require additional compression of the gas. Ideally, the compressor should be located close to the producing wells and be sized to match the expected production rate of the coalbeds. A pipeline was constructed to gather and transport the natural gas from the coalbeds and the deeper formations. The pipeline consists of approximately 14,000' of 2" plastic pipe conforming to ASTM standards for natural gas.

Initial water production from the coals and from the deeper natural gas formations was not excessive. Typically, a string of tubing was installed in the well for swabbing or pumping, and a 100-barrel water tank was installed to handle water production. During the cementing, stimulation, and production stages, available standard completion and production equipment were used which did not require the design of any special field equipment.

### 3.5.4 Projected Economics of the Selected Test Areas

Five potential well locations were selected during the project. These sites were projected to produce from the Big Lime, Ravencliff, and the major coal seams. Initial gas-in-place (IGIP) reserve estimates for the proposed sites were computed based on Figure 3.5.1. The recoverable gas was assumed to be 60 percent of the IGIP. Using the developed parameters for each of the sites identified in the Phase I report, the economical analysis projected that each of the sites would produce economically under those conditions.

Figure 3.5.2 shows a projected cumulative methane production curve for a hypothetical well producing from the Pocahontas and Beckley Seams in southern West Virginia.

Detailed cash flow analyses were conducted for the proposed sites which were then ranked and identified for drilling and testing the developed methodology. Results of these analyses are summarized in Section 7.0 of Volume II of the Topical Report on Phase I.

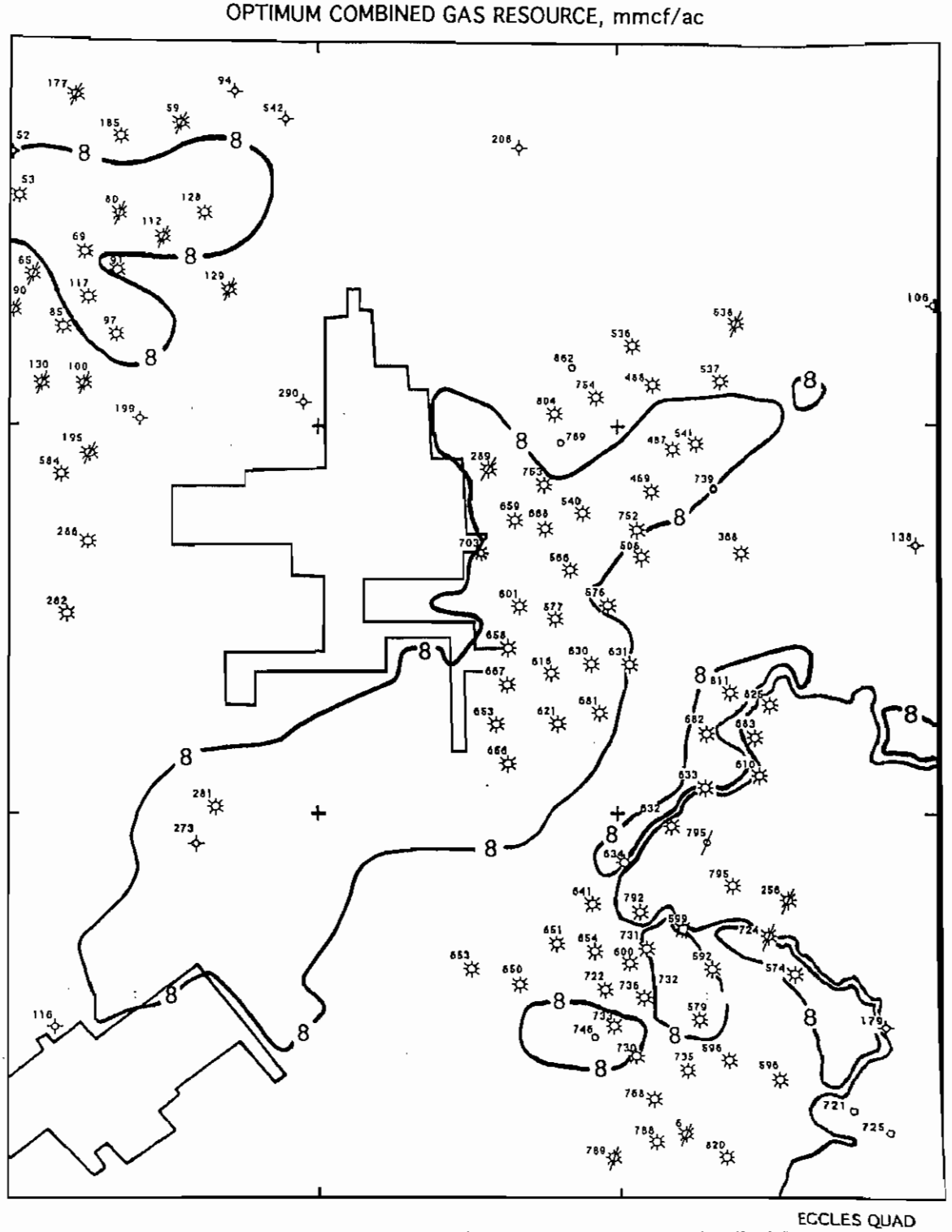



Figure 3.5.1 - Optimized Combined Resource Map for Coalbed Methane and Conventional Natural Gas in the Study Area

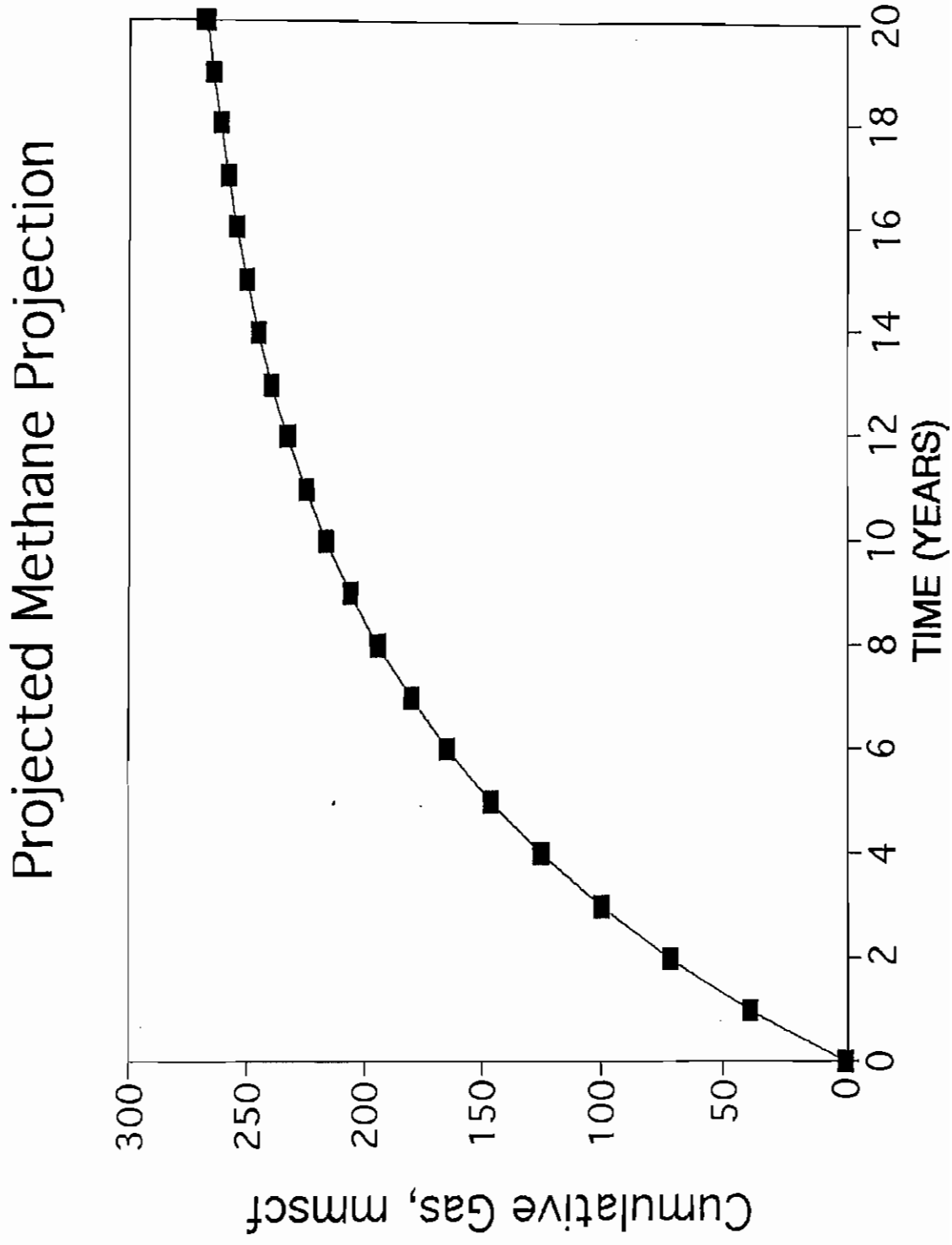



Figure 3.5.2 - Hypothetical Cumulative Methane Production Curve for a Well Producing from the Pocahontas and Beckley Seams in Southern West Virginia.

## 4.0 PHASE II ACTIVITIES

### 4.1 Rationale

Phase II activities were designed to test the exploration methodology by drilling, testing, completing and producing wells drilled at a number of the nominated sites. The site selection process was designed to maximize the probability of finding commercial production at a particular site even though conventional natural gas and coalbed methane resources might be individually non-commercial. The optimization technique ranked potential drill sites according to the probability of all interacting components being present. A site located outside of an optimum area might still be productive, but would not likely be as profitable as a site in the higher-ranked area. The additional probability of finding commercial production from multiple producing formations was encouraging but needed to be tested by drilling and production for verification.

Phase II activities began with the drilling of the well located in the optimum area. Three wells were planned to be drilled to verify the concept, however most of the area selected by the process had already been drilled and wells were successfully producing gas but generally from only one or two horizons, and none were producing from coalbeds. For this reason two sites were located just outside of the optimum area where probabilities were still significant.

### 4.2 Work Plan for Phase II Activities

A work plan was prepared which included a review of the site selection activities, confirmation of sites by conducting field geoscience studies such as resistivity surveys, geochemical surveys and seismic surveys.

The work plan outlined each area of activity that was to be conducted during Phase II operations (see Appendix 14.1). Part of the plan was the preparation of a detailed test well plan for each well drilled. A summary of the drilling plan for Test Well #1 is presented in Appendix 14.2. These plans were reviewed and approved by DOE before field operations were initiated.

The primary elements of the Phase II work plan was site-specific geoscience studies, lease acquisition, drill plan development, drilling, completion, stimulation and testing operations, pipeline construction, and technical analysis and report preparation. A separate plan was prepared for the stimulation of each well. This was necessary to be able to examine the economic potential of different stimulation methods which might be applied to the coalbeds.

### 4.3 Lease Acquisition

Surface and mineral rights ownership maps covering the five candidate sites were obtained from the Raleigh County, WV, Courthouse. A review of the ownership maps revealed that there were only three or four mineral rights owners involved in the area selected. One of the top ranked locations was subject of a lawsuit contesting ownership of the mineral rights so this site was eliminated from further consideration. The other sites were all part of a group of leases assembled more than forty years ago by Southern Land Company, a large company

involved in the development of coal, oil, gas, and timber.

Project personnel made initial contact with Southern Land personnel and made arrangements for a meeting with the current lessor of the coal mineral rights to discuss leasing of coalbed methane rights. This meeting was held in September, 1991, and the coal lessors, New Beckley Mining, Inc., was agreeable to providing access to the coalbed methane. Development of a sublease agreement was initiated immediately and the first iteration transmitted to New Beckley Mining in early October. Several meetings were held over the next few months to discuss various aspects of the Farmouts and leases including royalty overrides, separation of production, insurance to protect the coalbeds from accidental damage or destruction.

Separate sublease agreements had to be negotiated for the conventional gas resources (non-coalbed gas). Southern Land, which originally owned all minerals in fee over an approximately 8,000-acre block in Clear Fork District, had leased the gas and oil mineral rights to United Fuel Gas Company (now Columbia Gas), which later traded the leases to Cabot Oil and Gas Corporation. Cabot agreed to give farmouts (sub leases) with certain restrictions which would have to be negotiated. An initial agreement draft sublease for the conventional gas was developed with Cabot in September of 1990. The final agreement was signed in late April, 1991, just a few days before drilling operations were initiated.

Negotiating the sublease agreements was quite time consuming and was one of the most difficult tasks accomplished during the project performance. The lease agreement was finally signed on April 29, 1991, nearly eight months after the initial agreement to sub lease.

The coalbed methane subleasing agreement was unusual and may have been unique. Ownership of the gas from coal seams was held moot as the agreement called for sharing of coalbed methane revenues by both potential owners (coal and natural gas lessors). A model lease that should be applicable in situations similar to this is presented in Appendix 14.5.

## 5.0 GEOSCIENCE STUDIES

The Multi-Strata Project included several special geoscience studies:

(a) A lineament study was conducted for the four quadrangle study area by Marshall Miller Associates.

(b) A fracture study, geochemical, and electrical-resistivity surveys were conducted by Mammoth Geo for the target area.

(c) A pair of seismic lines was run along Sandlick Creek by ESI with processing by GeoData.

The primary objectives of the geoscience studies were to collect geophysical and geochemical evidence that would support or refute the geostatistical studies, and to refine the prediction of areas where enhancement of reservoir properties may have occurred as either a function of tectonic or sedimentologic processes. These studies provided additional insight relative to the

specific sites indicated by the geotechnical methodology.

## 5.1 Lineament Study

At the initiation of the Multi-Strata Project, Marshall Miller Associates (MMA), of Bluefield, Virginia, was contracted to perform a photolineament study of the original four-quadrangle (Beckley, Crab Orchard, Eccles and Lester) study area. This research was conducted as soon as the project began to gain an understanding of the general regional structure and to locate highly-fractured areas where subsequent studies might be focused.

### 5.1.1 Methodology

For this project, MMA used Landsat Thematic Mapper, SLAR and high-altitude, color, near-infrared photography. The Landsat and SLAR images were electronically enhanced and analyzed using advanced video techniques. The high altitude photos were viewed in stereo pairs.

The original analysis was conducted by two geologists, independently. The results were then compared and the lineaments evaluated for validity and significance. Each feature was classified as "Primary," "Secondary" or "Tertiary." The primary features theoretically represent the most significant fracture zones with the greatest intensity of fracturing and the deepest extent of penetration.

Following the mapping phase, the trends were digitized and the data sets manipulated by computer to produce a series of rose diagrams showing the orientations of the linears across the maps. Separate rose diagrams were prepared for the study area as a whole, for each quadrangle, and for quadrant subdivisions of the maps.

Final maps were prepared by a computer program that gridded and contoured the data and performed Krigging analysis. Maps were drafted showing all the lineaments. One map depicted "Total Lineament Length Per Unit Area" and a second map showed the same information with the lineaments weighted according to their significance as Primary, Secondary or Tertiary features, where one Primary feature was weighted as equal to three Tertiary features and a Secondary feature to two. Finally, a third-order trend-surface map was prepared.

The lineament study is enclosed as Appendix 14.1 and the results are summarized in the following section.

### 5.1.2 Results

The most prominent regional lineament trend cuts across the study area, an angle between N25E and N40E, following the general Appalachian structural grain. To the southeast, on the Crab Orchard Quadrangle, this trend swings more toward N15-20E. This latter fracture trend generally parallels the low-amplitude folds in the area. These features are relatively young, having formed during the thrusting and folding of the Alleghenian Orogeny.

A secondary lineament trend runs through the area between approximately N5W and N10W. This orientation is much more ancient, probably dating back to a great episode of through-Crust Basement faulting produced during the one-billion BP Grenvillian Orogeny. The scale of these faults was so vast that they have persisted as zones of weakness which have been susceptible to reactivation up to the present day, and have moved recently enough to influence current-day fracture patterns and drainage. Additional significant trends identified by MMA run N60-75E and N20-30W.

MMA identified three Primary Lineaments crossing the study area. Two of these lineaments run approximately north-south, following the Grenvillian trend. One of these lies along the east edge of the four-quadrangle area, following Piney Creek Gorge. This is the site of a likely Basement fault identified in the geologic study of the area. A second trend runs south from the Stephens Lake area, again in the vicinity of a Basement fault. This break makes west edge of the high block that has influenced the Big Injun production in the area. The third trend follows the West Fork of Winding Gulf. This feature parallels the Appalachian grain and the local fold axes.

### 5.1.3 Relationship Of Lineaments To Production

The original premise for the lineament study was that production should be enhanced in highly fractured areas along the lineaments. The fractures theoretically could create zones of secondary porosity and enhance permeability in reservoir formations.

Direct observation of the initial open flow data, productivity figures and total projected reserves does not show any strong association or relationship between the lineaments identified in this study and the better reservoirs on the map. Most of the pool outlines show no relationship to the lineament trends. The reserve contours do not parallel the identified features and most of the best wells are located well off the lineaments or their projections. On the other hand, there does not appear to be a negative correlation between the lineaments and reservoirs. Such a negative correlation could occur if the degree of fracturing was so intense that reservoir cap rocks had been shattered and their integrity as seals had been destroyed. Such intense tectonics are found in the Rome Trough area of West Virginia, but would not be expected in this more gently deformed region.

The lack of correlation, either positive or negative, between the lineaments and production and projected reserves gave an early indication that fracture porosity has not played a dominant role in the reservoirs in this area. It appears that the local reservoirs have been controlled mainly by primary porosity and that the depositional environment and early diagenesis were the major controlling factors in reservoir formation. Later fracturing does not seem to have substantially altered the reservoirs or to have added substantial secondary porosity or permeability. This is a result of the low level of tectonic activity in this portion of West Virginia and the quality of the primary porosity in the oolitic Big Lime Limestone and the Ravencliff river channel sandstones.

## 5.2 Fracture Study, Resistivity and Geochemical Surveys

Once the main target areas had been identified, as described in Volume I of the Topical

Report, a series of concentrated geoscience studies were conducted at the specific sites that had been indicated as most favorable by the geotechnical analysis. Although the lineament study and the later geologic analysis had showed that primary porosity was much more important in controlling production from the conventional reservoir formations than secondary fracture porosity, it was felt that fracturing might still benefit the conventional reservoirs to some extent and that coalbed methane production rates could be increased in more highly fractured zones within the main coal seams. Mammoth Geo, of Barrackville, West Virginia, was employed to conduct a series of geoscience studies of the specific target areas.

### 5.2.1 Methodology

Mammoth Geo began their work with a detailed side-looking low altitude radar (SLAR) and high-altitude photography lineation study (Appendix 13.2) of the Sandlick Creek and Harper Branch drainage areas where the reservoir conditions seemed to be favorable in both the coals and the conventional formations. A number of local fracture trends were tentatively identified (Figure 5.2.1) and Earth Resistivity Profile Survey (ERPS) lines and geochemical survey locations were laid out.

### 5.2.2 The Earth Resistivity Profiling Survey (ERPS)

Eleven ERPS lines were surveyed, encompassing 393 Stations over 5210 feet for 1179 data points. ERPS measures the electrical resistance of a rock. The process assumes that a fractured rock contains water in the fractures. This means that the resistivity of a rock should drop significantly in a highly-fractured area. Three different electrode arrays were used at each Station with three resistance readings being taken. The results were entered into Mammoth's computer system. Three sets of resistivities were calculated and the results were plotted.

Mammoth concluded that the resistivity values supported the results from the lineation study and that several fracture zones crossed the study area. Each of these fracture zones had a surface expression between 20 and 50 feet in width. Five significant features, zones A, B, C, D and E, were identified. The first well, TW-1, lies within a few feet of fracture trend A, one of the longest features identified.

### 5.2.3 The Geochemical Survey

In addition to the resistivity survey, which confirmed the presence of fracturing, a soil-gas geochemical survey was run to determine if there were surface indications of natural gas or methane (Appendices 14.3 and 14.4).

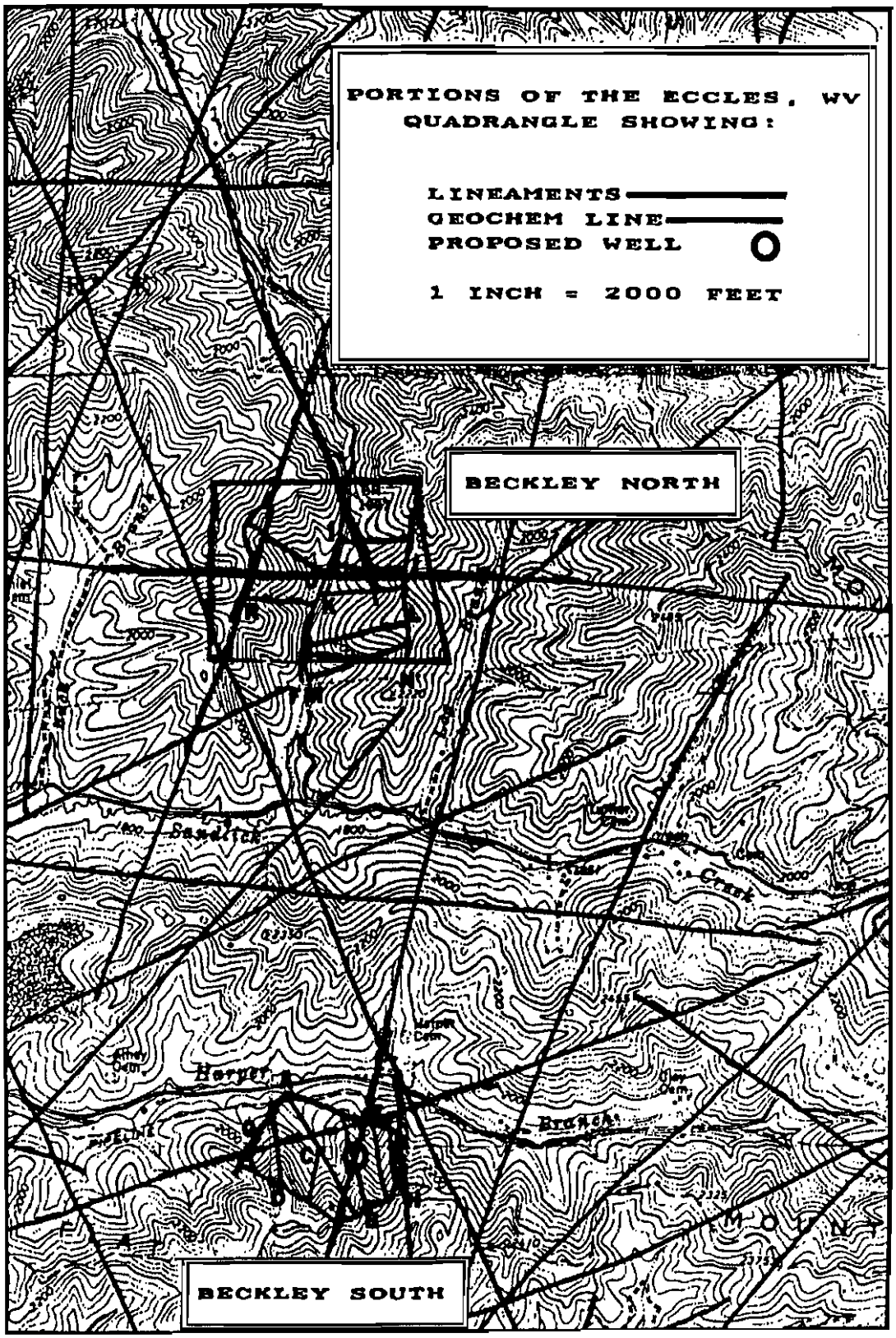



Figure 5.2.1 - Fracture Study, Resistivity, and Geochemical Surveys Area

This survey was focused on sensing the presence of hydrocarbons in the soil and identifying their types. Any hydrocarbons detected were assumed to be working their way to the surface through microfractures from deeper reservoirs. The types and ratios of hydrocarbons provided clues to the nature of the reservoirs at depth. This methodology does not provide any quantitative clues as to the amount of the resources detected or to the depth of the reservoirs, but it is theoretically possible to be distinguish oil reservoirs from gas reservoirs and to distinguish the amount of methane and other hydrocarbons in the soil.

Detailed surveys were taken around the TW-1 well (not yet drilled at the time of the surveys) and to the north around the other projected target area. 96 samples were collected at 100-foot spacing along seven lines near the TW-1 projected location (Figure 5.2.2). 163 samples were taken along ten lines in the northern study area (Figure 5.2.3). The samples were collected in vacuum bottles via probes inserted into the soil to a depth of three feet.

The laboratory analysis was conducted by flame ionization chromatography with identification of Methane (C1), Ethane (C2), Propane (C3) and Butane (C4). Gross methane percent and ratios for C1/C2, C2/C3, and C3/C1 were calculated and recorded. The relationship of these various components was plotted on a series of maps (see Appendices 14.3 and 14.4).

### 5.2.4 Results

Maps were prepared showing the methane present, the various hydrocarbon ratios, the oil-prone and gas-prone areas, and composite oil/gas indicators. These results were interesting since there were extensive "oil" areas shown by the survey. According to the West Virginia Geologic Survey data base, there has never been any oil reported in any well in the Raleigh County study area. However, subsequent mudlogging of the test wells and a corehole showed signs of dead oil in a shallow conglomeratic sandstone validating the geochemical findings. TW-1 fell along the edge of an oil-prone area on the southern map and just west of a large gas-prone area.

### 5.2.5 Relationship of Results to Production

The presence of extensive oil indications in a region that had never produced oil was originally somewhat disconcerting, although the discovery of dead oil in the core and mud log samples helped to explain the result. In addition, the Methane Percent Maps did not show any indications of methane in areas where coreholes showed many feet of very high-methane-content coal.

In analyzing the final maps, it was noticed that there was a close correspondence between the oil-prone areas and the local topography. With minor recoloring, the original Oil Composite Maps could be converted to a rough approximation of the local topographic map (Figures 5.2.4 and 5.2.5). Most of the samples with "oil" signs were collected high on the hill slopes and along the crest of the ridges. This is in the general vicinity of a significant, cliff-forming sandstone unit. This suggests the possibility that several of the resistant, coarse-grained sandstone units that form the ridge tops may once have held substantial oil reserves that dissipated long ago as erosion exposed the sandstones to the elements. The survey may have

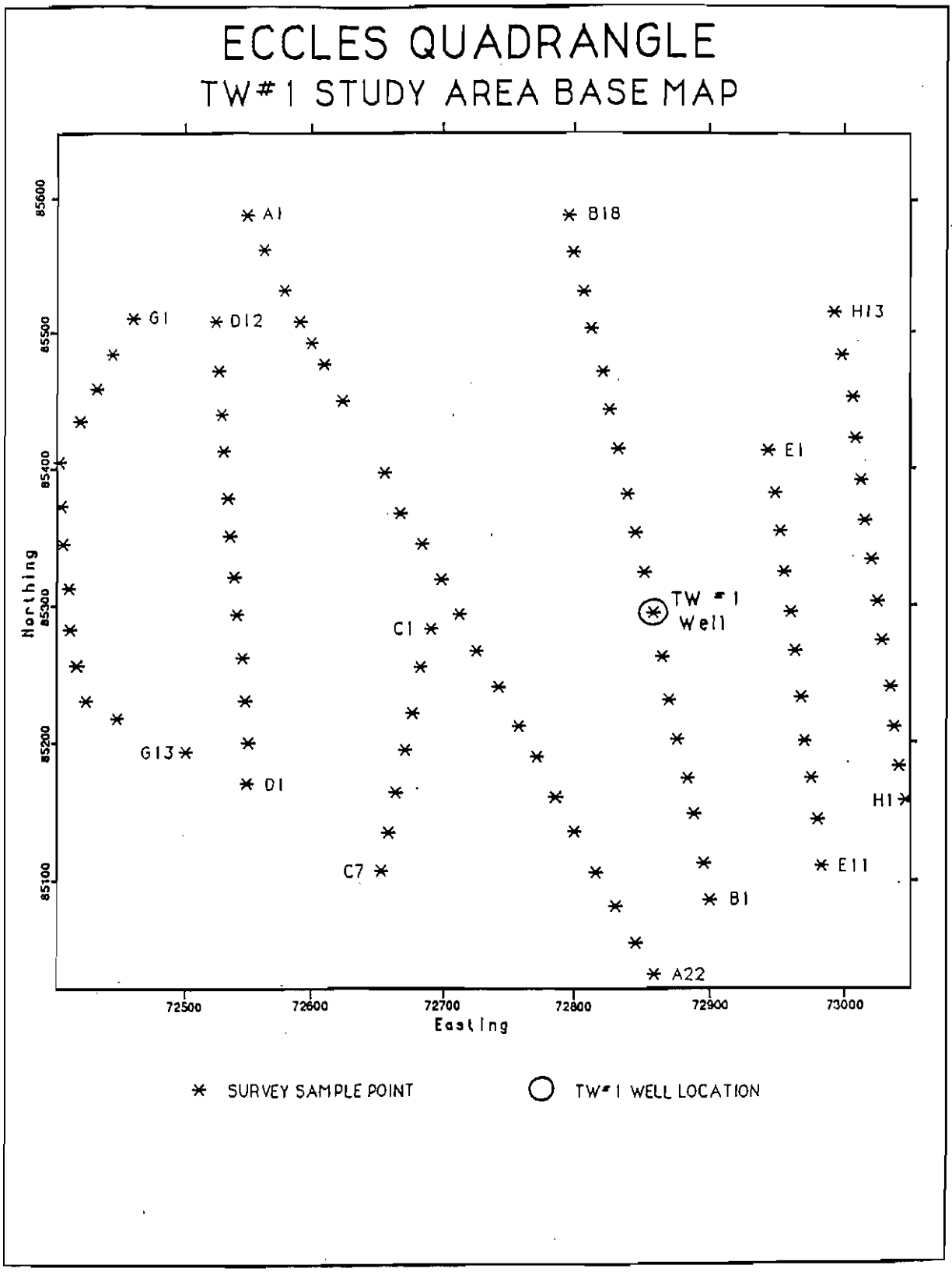



Figure 5.2.2 – Geochemical Survey Points Near TW-1

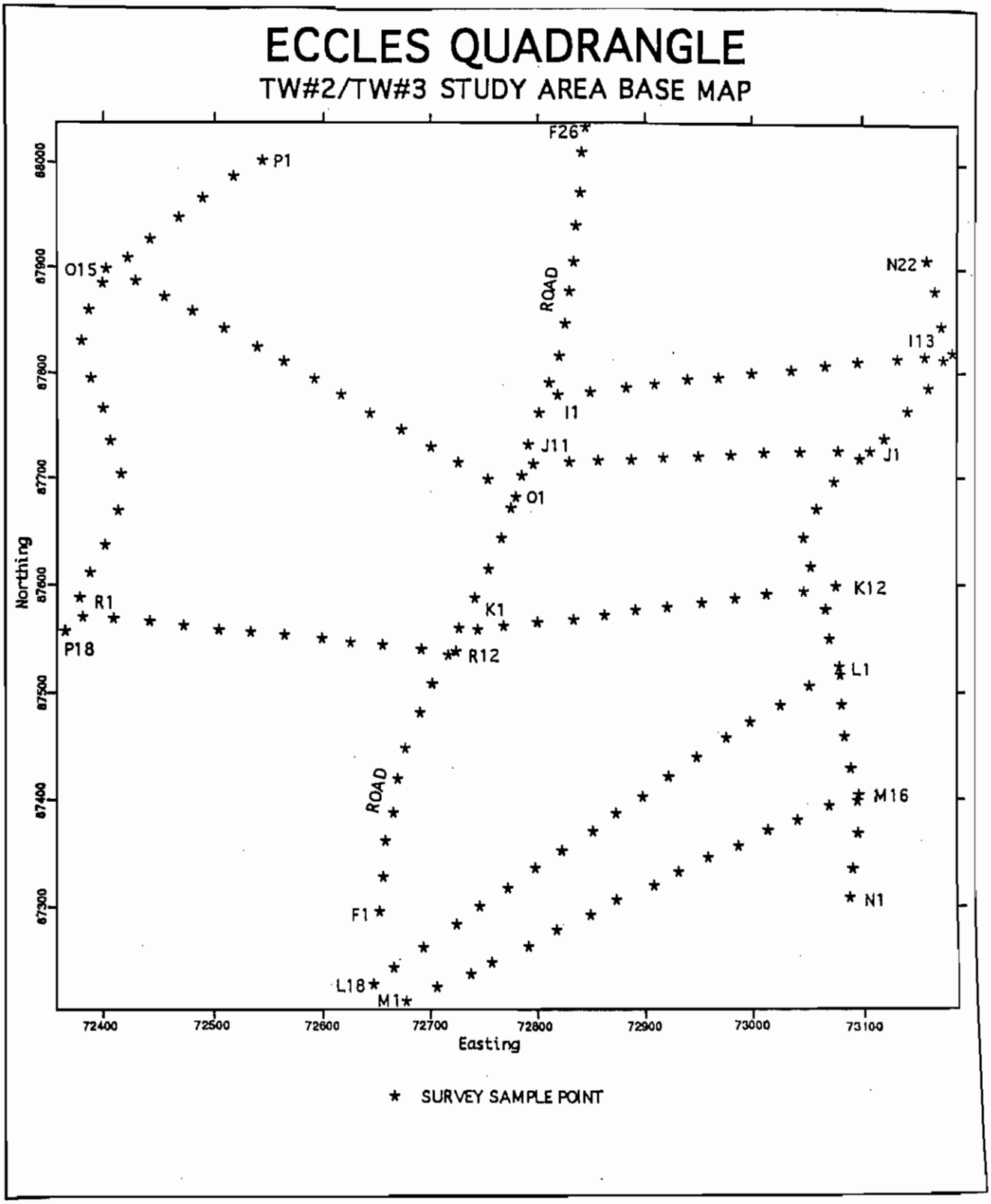



Figure 5.2.3 – Geochemical Survey Points in Northern Area Near TW-2 and TW-3

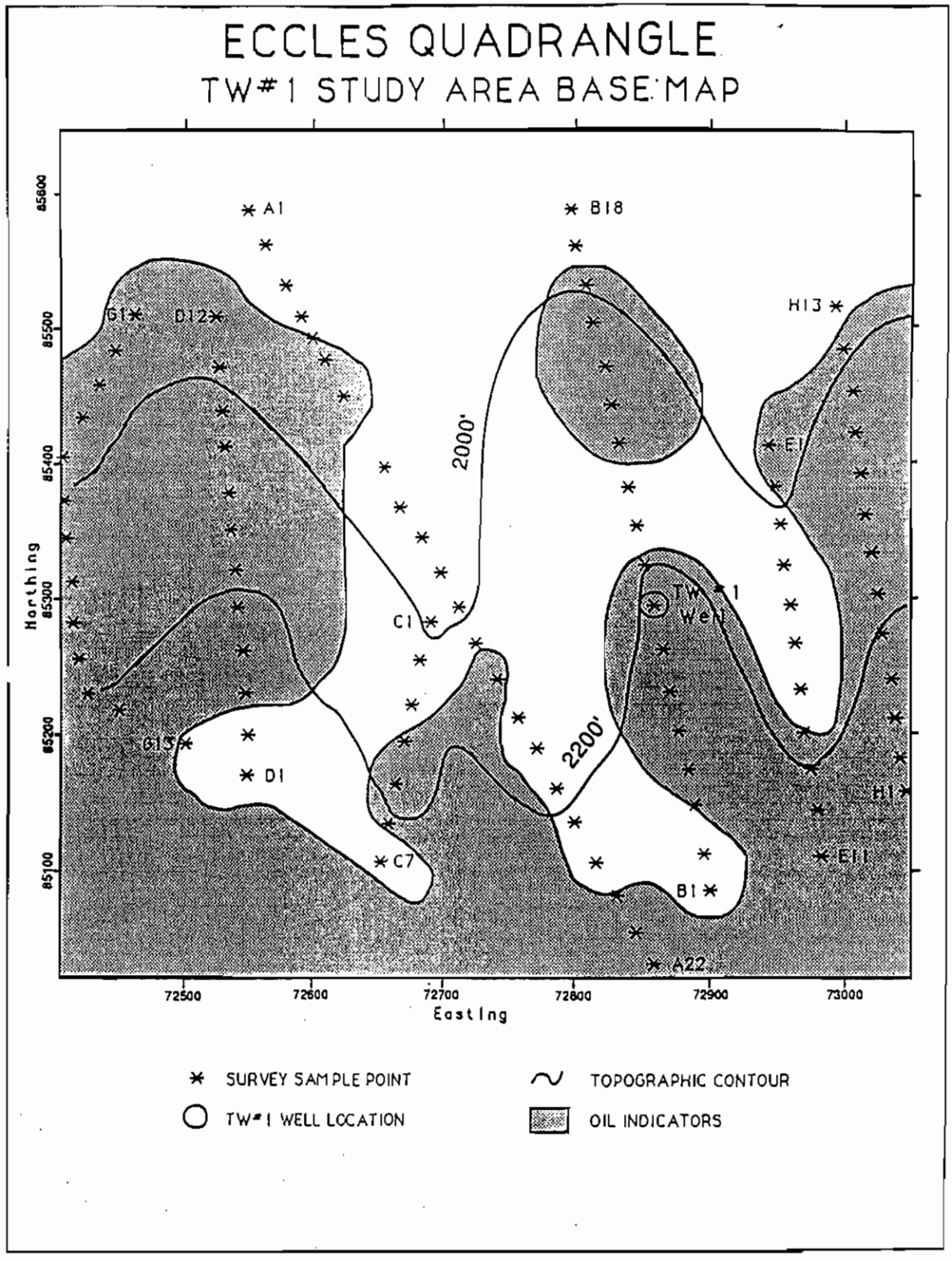



Figure 5.2.4 – Geochemical Results Indicating Oil-Prone Areas Near TW-1, with Superimposed Local Topography

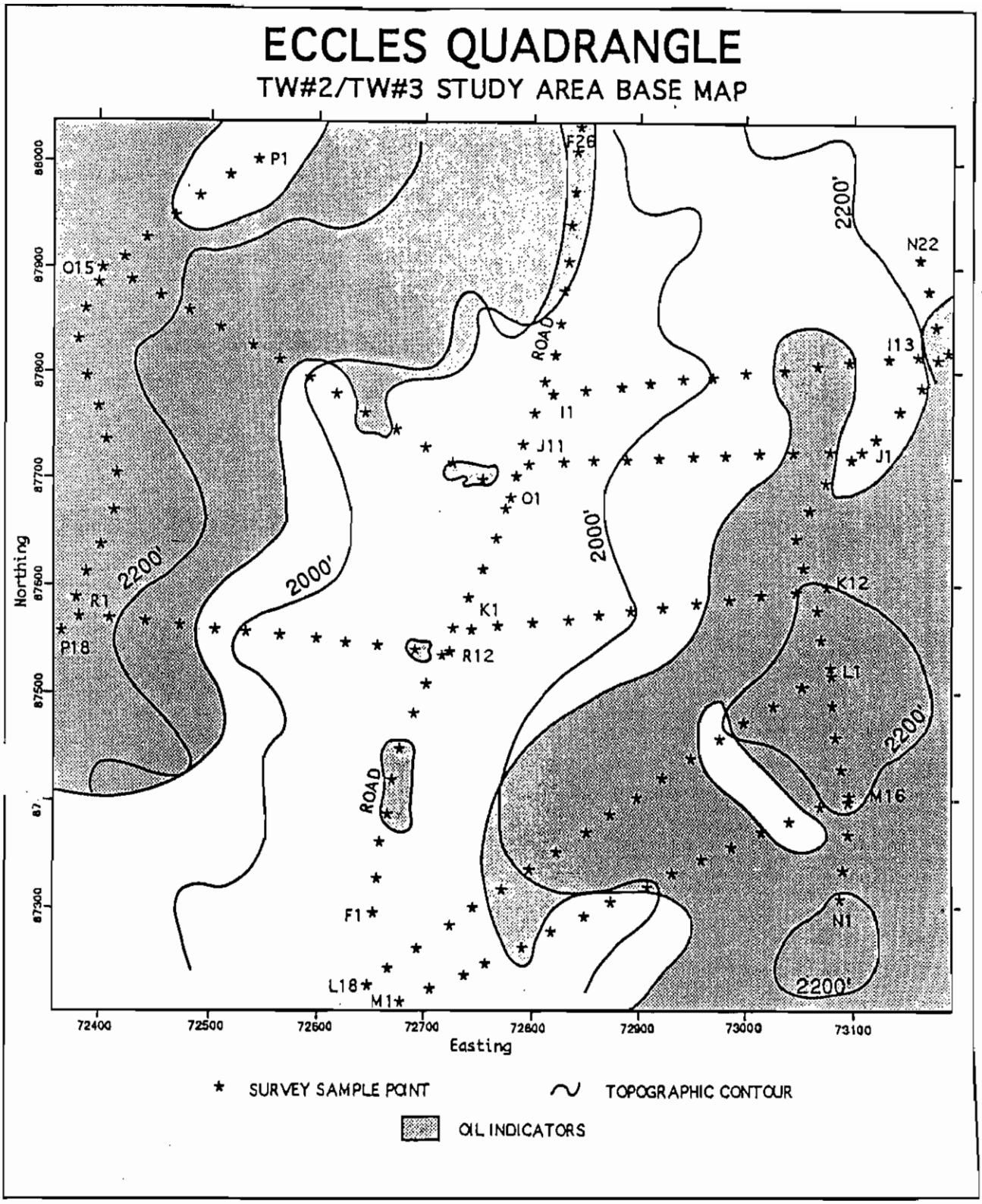



Figure 5.2.5 – Geochemical Results Indicating Oil-Prone Areas Near TW-2 and TW-3, with Superimposed Local Topography

picked up residual traces of this oil in the soil on the high ground. The same correspondence shows up on both the north and south survey maps.

The natural gas indicators were largely located in the lower topographic areas, although there were many exceptions to this. In the survey map around the TW-1 location (Figure 5.2.6), the valley along Harper Branch show continuous indications of natural gas. The two major tributary valleys also showed good indications of natural gas. It is possible that fracturing had provided a more ready location for erosion, forming the valleys, and also had formed a migration route from the deeper, gas-bearing reservoir units, causing a concentration of gas indicators in these valleys.

In the study area around TW-2 and TW-3, there was a solid line of gas indications up the valley floor and near the crest of the ridge along the west edge of the map (Figure 5.2.7). The indicators near the ridge crest can be interpreted as a straight linear feature of constant width. This line very closely approximates one of the photo linears, which also showed up in the ERP survey, where it was identified as Feature E (Figure 5.2.8). This "E" line was one of the longest linears identified by Mammoth Geo, and may represent a significant fracture zone and migration route along which natural gas and methane are moving to the surface from depth.

## 5.3 Seismic Survey

The Multi-Strata Program was originally planned with the idea of attempting some high-resolution seismic work to identify fractured areas in the shallow reservoir units and coals. However, experience relatively nearby in Nicholas County and to the south in Mercer County demonstrated that there was a high probability that this effort would be futile within the available budget. Reflector quality in the shallow units, above the Onondaga, was generally very poor, even using high frequencies and very expensive short-spacing intervals. The key formations could not be counted on to reflect reliably over any distance. For the extremely shallow coals and the specific target reservoir units, it was unlikely that differing qualities of reflectivity could be identified in fractured and unfractured areas simply using high-resolution survey equipment and techniques reasonably available at that time. Because of the potential problem with using high-resolution seismic, the final plan called for a single line of conventional seismic over the target area to look at the basement and deep reflecting formation with a high-resolution survey along the same line to attempt better definition of shallower formations.

In most of the Appalachian Basin, the multi-hundred-million years of diagenesis and tectonic activity have homogenized rock velocities in the shallow section to the point where there is little velocity contrast between the coals and surrounding units, or within formations like the Greenbrier between porous and non-porous zones. Vibroseis work in Nicholas County, in an attempt to identify zones of oolitic porosity in a very thick Greenbrier section, showed that the Greenbrier was not reflecting in that area at all; while the much thinner Berea was probably the closest unit to the Greenbrier to provide a moderately reliable regional reflector.

In addition to poor reflectivity and unreliable quality, the structural relief in this portion of southern West Virginia is minimal. Attempting to identify shallow fracture zones by seismic

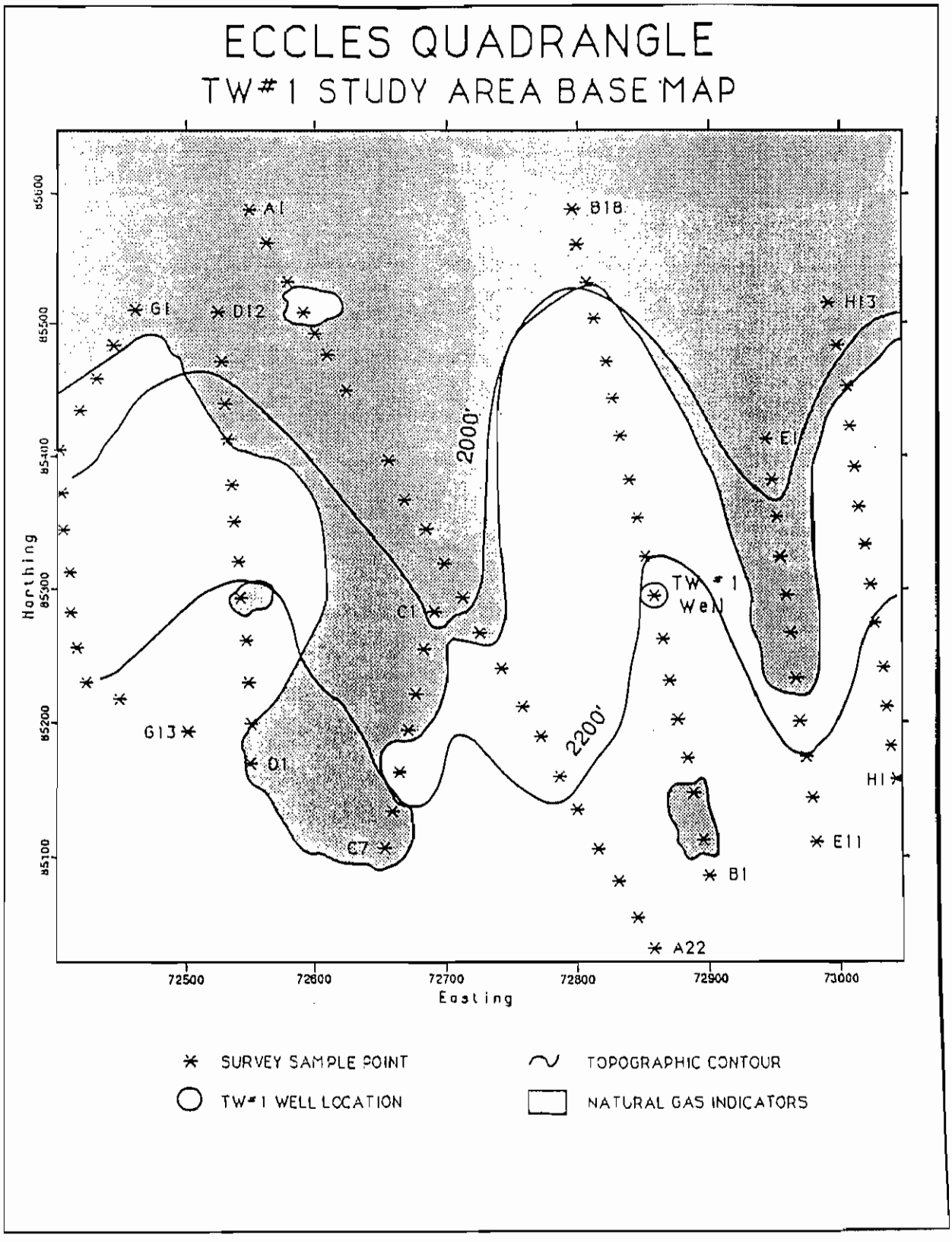



Figure 5.2.6 – Geochemical Results Indicating Gas-Prone Areas Near TW-1, with Superimposed Local Topography

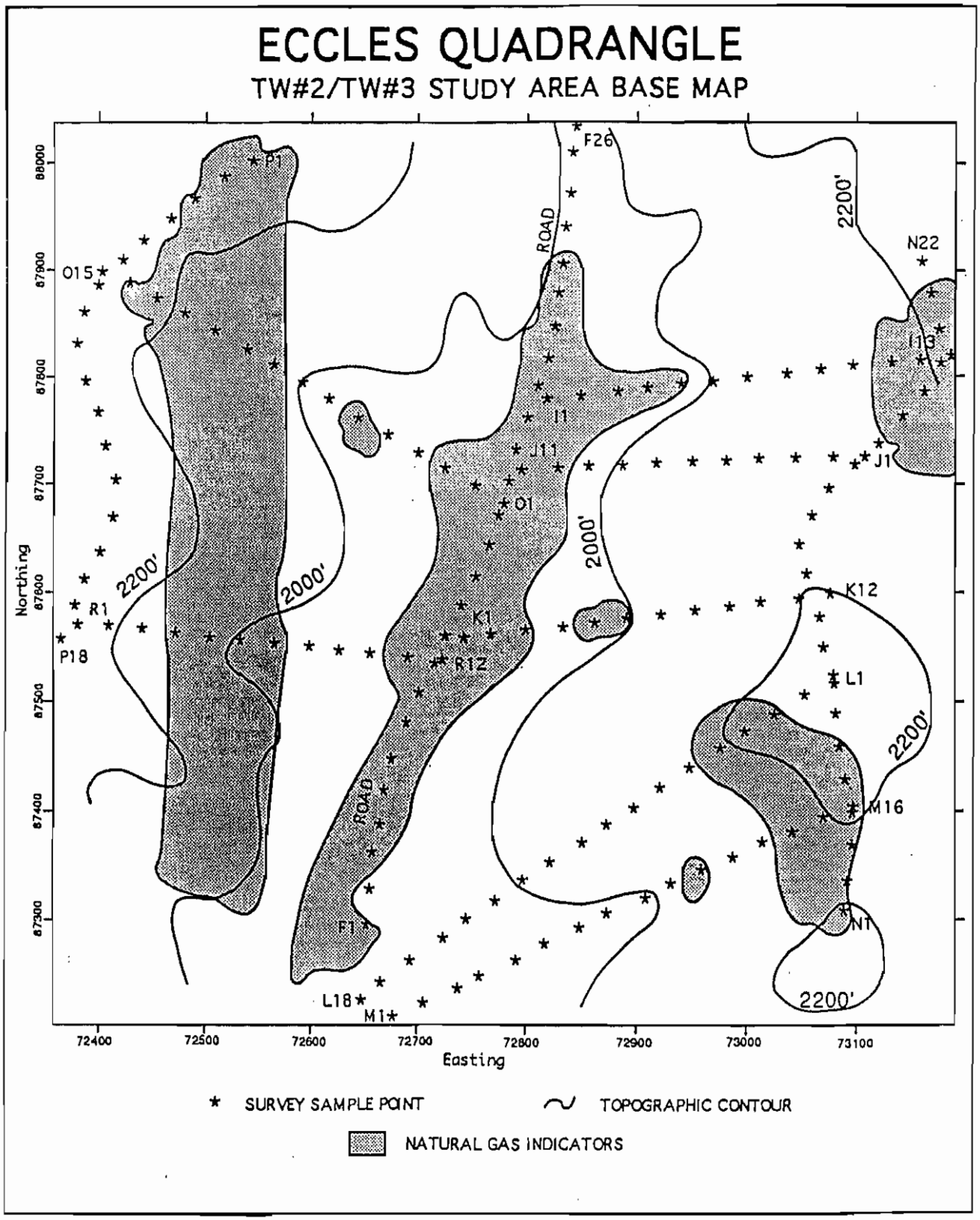



Figure 5.2.7 – Geochemical Results Indicating Gas-Prone Areas Near TW-2 and TW-3, with Superimposed Local Topography

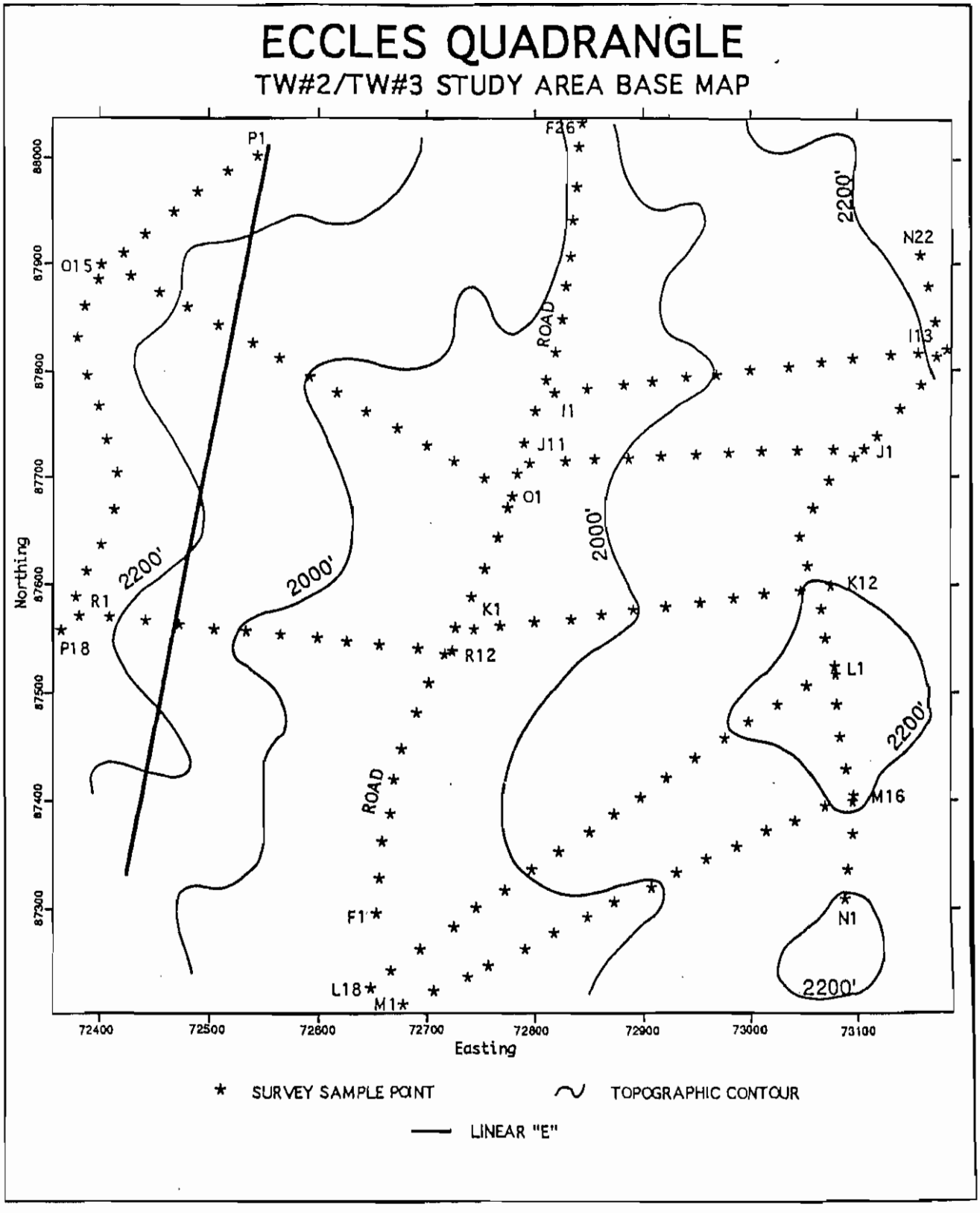



Figure 5.2.8 – Geochemical Base Map Area Showing Large Linear Feature with Superimposed Local Topography Near TW-1

methods would be difficult, whether the study was based on changes in shallow reflector quality, on offsets of the shallow traces or by association with offsets of the deeper reflectors. It would generally not matter whether conventional or high-resolution data were being used. Most structures on the Southern West Virginia Massif have a relief at a scale which closely matches the limits of seismic processing. Even at the Basement level, vertical offsets are generally so slight that most examples of relief on the Basement reflector can be interpreted as faults, as slight processing problems, or as incorrect velocity picks.

With so many variables and such minor structures, seismic data can only be used as one tool in combination with all the information from shallow geologic studies. In an area like this, the geophysicist needs to work very closely with the geologist. He or she should have a full seismic section, showing all the reflectors from the Basement to the shallow zones. A possible seismic discontinuity is an important clue when it occurs in an area that has been interpreted as the margin of a structure or when it occurs along a significant drainage trend or lineament. When shallow features such as formation pinchouts or lithologic changes coincide with deep seismic discontinuities, the lines of information support and reinforce each other, lending credibility to the concept of deep faulting with episodic reactivation. These multiple data fit the concept of an area that has experienced deep structural control of depositional environments, with recurrent Basement movements and adjustments caused by changing stress fields during the Paleozoic.

Bids were requested from three seismic companies to see what techniques and equipment they would recommend that could be provided within the project budget constraints. The bid that offered the most useful information was submitted by ESI of Conroe, Texas. Their proposal was for two lines, one of which was to be shot using conventional techniques and frequencies along the entire length of Harper Branch, midway between the two primary target areas (Figure 5.3.1). The second line was to be a 3,000-foot, high-resolution section covering the area closest to the projected wells.

The conventional line was designed to provide a look at the Basement, Knox, Trenton, Tuscarora, Onondaga, and any reliable shallower reflectors. The high-resolution work was intended to give an enhanced view of any shallower reflectors which might show up. Due to the constraints of topography and funding, both lines were to be shot along the same road. This method would allow the detection of faults or non-reflecting/poorer-reflecting zones, but would give no information on the orientation of the faults.

### 5.3.1 Methodology

Geological analyses of the study area suggested the possible existence of a deep-seated block that had been recurrently uplifted by small amounts relative to the areas on either side. The North-South orientation of this feature followed the Grenvillian trend, and it was surmised that this uplift might have been controlled by movement within the Basement as it shifted periodically during the Paleozoic. The seismic lines were laid out to cross the margin of the fracture at 90 degrees. Similar lines in Nicholas and Mercer Counties indicated that the relief at the Basement level would probably be minimal, but that there should be identifiable Basement discontinuities which would probably correlate with anomalous features like faults, lineaments, and productive oil or gas fields in the shallow rocks.

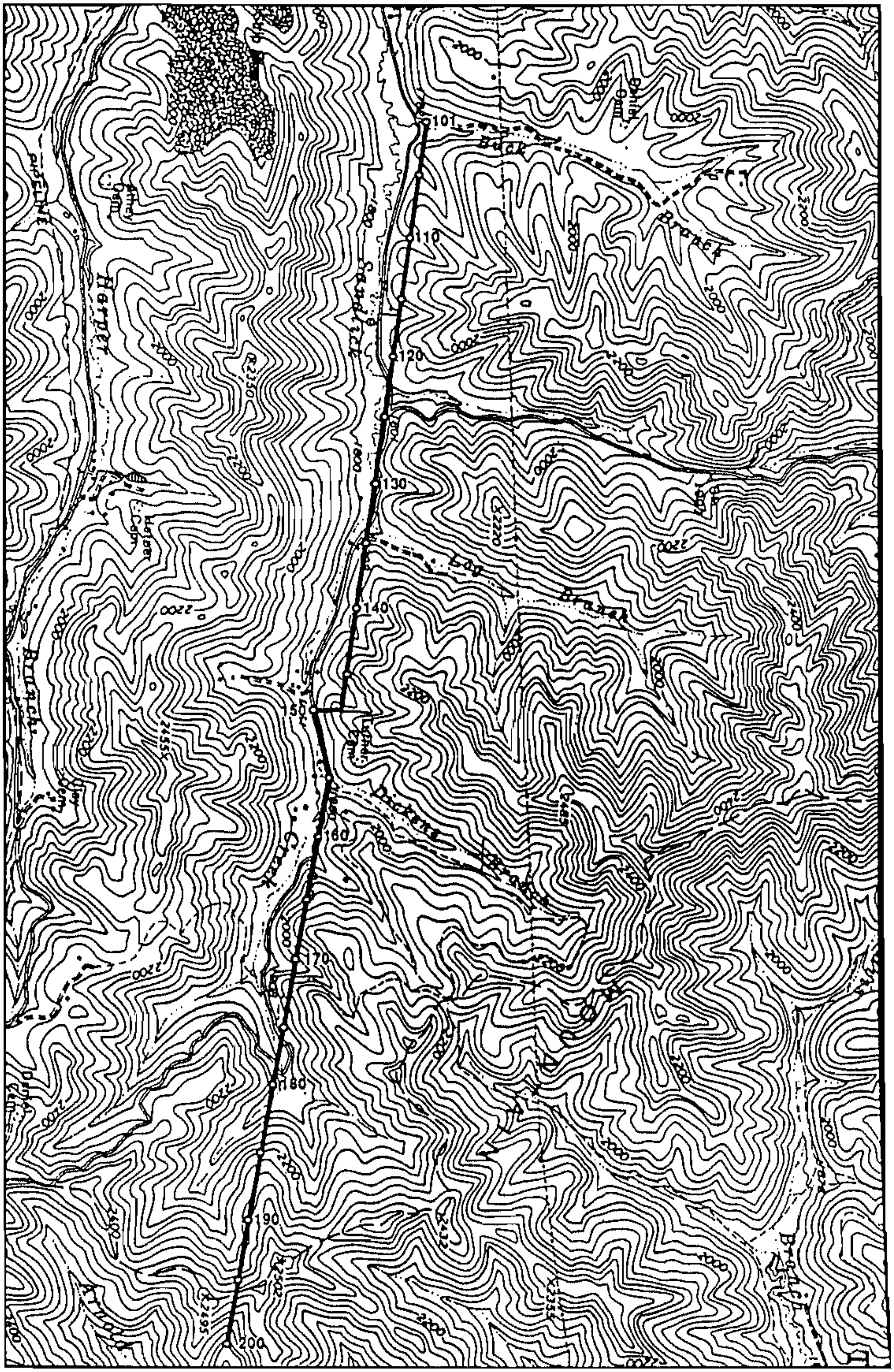



Figure 5.3.1 – Location of Seismic Line with Local Topography

While it is desirable to shoot seismic data in the immediate vicinity of a prospective well and to have multiple seismic lines in an area to define the orientation of features that are identified, budget restrictions made this impractical. Lacking funds to shoot additional lines or to buy existing brokered seismic lines to form a larger data bank, a detailed understanding of the shallow geology had to be relied upon to compensate for the lack of geophysical data.

ESI collected the data, with the processing performed by GeoData of Tulsa, Oklahoma. The lines were processed in conventional and migrated formats. The conventional line was shot and processed with no problems. ESI did its shooting during the hottest week of the year and experienced an electrical recording or observer's notes problem with the high-resolution line. It was impossible to identify zero time on the high-resolution records, and this section could not be correlated and printed.

### 5.3.2 Results

For the conventional seismic section, the GeoData processing show very-good-quality reflectors and continuity for the Basement, Knox-Beekmantown, Trenton, and Onondaga. The Tuscarora reflector could be identified, but was of much lower quality and reliability, not uncomman for the Tuscarora in West Virginia. The reflectors did show a regional dip to the west. Several reflector discontinuities and anomalous areas show up, including those in the crucial prospect area.

A small depression or graben-form appeared on the seismic section between Stations 120 and 130 (see Figure 5.3.1). This was the target zone coinciding with the edge of the positive Basement block. The reflectors there displayed lower amplitude, and had deeper times. The feature did show up at the Basement level and on the shallower reflectors with the edges of the depression stacked vertically above the offset at the Basement level. The migrated section showed an offset on the Onondaga reflector near Station 122. Since relief on the features was minimal, the seismic times were entered into a spreadsheet and graphed in a manner that allowed the small offsets to be emphasized.

The combination of poorer quality, lower amplitude reflectors and the graben-form on the seismic section indicate the presence of either a down-dropped area along the margin between shotpoints 120 and 130 of the Basement block, or a very intensely fractured zone which is slowing velocities, reducing signal and reflector quality, and producing the artifice of a graben. The quality of the reflectors and the amount of relative depression at the Onondaga and Basement levels favored the interpretation of a down-dropped block. The relief on the trough appeared to be in the range of 80 to 90 feet at Basement level, near the limits of seismic resolution. However, since the feature shows up consistently at all levels over an interval of 15 to 20 traces, it can be identified with a reasonably high confidence level.

The western edge of the reactivated Basement block could be identified, but had a very low expression, abruptly rising approximately 100 feet, then flattening out onto a smooth summit. The highest areas on the block appear to be between 150 and 175 feet higher than the low areas to the east or west. The eastern end of the block shows a rapid drop, with little visible of the low region on the eastern end of the line. Topography prevented running the seismic coverage any further to the east. The severity of the surface relief may be related to the

faulting in this area.

Several abrupt elevation changes could also be identified on the reflectors within the block. Some of these probably represent internal faults. Two or three sets of these discontinuities, each affecting several reflectors, could be seen. None of these fault zones had relief of much more than 50 feet at the Basement level, but each coincided with north-south or slightly southwest-northeast oriented drainage. These features apparently mark the location of fault/fracture zones that have shifted recently enough to influence modern drainage.

Working with both the reflector times and the intervals between the reflectors, it appears that the most significant fault activity during the Paleozoic occurred along a fault around Station 180, on the eastern portion of the line. The data indicated that the Basement had shifted at that location and to the east of this point, had dropped by almost 100 feet by Trenton time. Much of this displacement was compensated for in post-Onondaga time by a reversal of the direction of movement along the same break. On the seismic section, the Basement shows only minor displacement at this Station, but the Tuscarora and Onondaga reflectors to the east of the Station formed a peak where the units that had filled the depression, now rise as a small horst.

Two other prominent faults on the line were those flanking the graben, roughly at Stations 120 and 130, and one at the east end of the positive block around Station 190. The fault at Station 190 had moved down to the east, with the time intervals indicating significant movement by Trenton time.

Additional faults could be detected in a zone between Stations 145 and 150 and around Station 163. Displacement at these locations were minor, but changes in the intervals between the reflectors, as well as drainage and lineament traces above these points, aid in the identification of these breaks.

The minimal offsets seen on most seismic data in southern West Virginia is a result of a combination of factors, including the minor role of tectonics and the subtlety of movements in this area, as well as reversals of movement and readjustments over time, such as that seen at Station 180. The stress regimes in eastern North America during the one-billion-year post-Grenvillian time period have included tensional episodes during the opening of the Rome Trough and Proto-Atlantic; successive compressions from various directions during the Taconic, Acadian and Alleghenian Orogenies; and renewed tension during the Triassic rifting and the opening of the modern Atlantic Ocean. Many Rome Trough-Aged normal Basement faults in West Virginia rebounded under later compression, and now display less offset than they achieved at their maximum throw.

### 5.3.3 Relationship of Results to Production

The minor offset of less than 200 feet at the Basement level on these faults indicated that movements here have been minor, but the sense of motion that can be interpreted from seismic information and shallow data supports the concept of a Basement block, east of Station 130, that had intermittently moved upward, relative to the region to the west. The

subtle differences in the depositional environments described for the Chesterian-age Greenbrier "Big Lime" Limestone and Beckley Coal units imply very gradual Basement movements during those time periods.

The thickness and isopach pattern of the Beckley Coal would imply a hypothetical maximum relief of the positive block during that time period of approximately ten feet, although not all of the coal pinchout pattern should necessarily be attributed to tectonics. The difference in water depth across the Big Lime seafloor was much more difficult to quantify. The Big Lime sea is generally described as having been very shallow water, so large depth differences were considered unlikely.

The conventional seismic data supports the concept of a positive Basement block and defined the boundary of the block to be within the target area. Several internal faults could be identified within the major block. A narrow graben-form runs along the target area, implying the possibility of significantly enhanced fracturing. The interpreted Basement fault pattern coincides with surface drainage features at each of the fault traces, suggesting relatively recent movements and fracturing above the deep breaks. With only one seismic line, it was impossible to project the faults or to tie the traces of the interpreted faults to specific wells or to relate productivity and proximity to seismic features.

## 6.0 TEST WELL NO. 1 SUMMARY OF OPERATIONS

Southern Land Company Test Well No. 1 was drilled on a 48-acre farmout lease from Southern Land Company, New Beckley Mining Company and Cabot Oil, and Gas Company. The well was one of three wells to be drilled as a confirmatory test of the geotechnical exploration method developed for this project. The location was an optimum location selected by the geotechnical procedure, while integrating the components of natural gas resource availability, and natural gas reservoir and structural development required to trap gas in the reservoir space. Other slightly higher ranked locations were developed, but those locations either had been previously drilled or had lease problems which could not be overcome in time to keep the project on a reasonable schedule.

Drilling operations began on April 30, 1991. After setting 30 feet of 13" conductor pipe, an 11-inch hole was drilled to the top of the Beckley coal. Drilling was halted to allow coring of the Beckley coal with a 7" bit. The well was reamed with a 10 5/8" bit after the coring was completed through the Pocahontas coals. A pocket was drilled 150 feet below the coals to hold water produced from the coals so that gas could be produced with little interference from the coalbed water. Eight and five-eighths inch ( 8-5/8") casing (1,241 feet) was installed and cemented in place to protect shallow aquifers.

A 7-5/8" hole was drilled beneath the shallow casing to the base of the Big Lime at 2,995 feet. The well was logged and analyzed, and zones for stimulation were selected. The 4-1/2" casing (2,972') was installed and equipped with a left-right-threaded nipple and collar to allow for its partial removal from the 8-5/8 inch casing. The Big Lime limestone was acid-foam-fraced while the Ravencliff sandstone was foam fraced through the 4-1/2" casing before a temporary bridge plug was set and the casing unscrewed and removed at the left-right nipple at 1,236

feet. This maneuver provided room inside the 8-5/8" casing to abrade slots through the casing into the coalbeds.

All three coal seams (Beckley, Poca #3, and Poca #4) were fraced with untreated sand laden water (a total of 4,390 bbls or 184,380 gallons). The water either flowed back or was swabbed from the coal seams. Each producing unit was tested after clean-up to determine the amount of gas production which could be expected.

The Big Lime and Ravencliff sand were projected to produce up to 54 mcfd while the coal seams were projected to produce up to 47 mcfd. The combined total gas production thus was projected to approach 100 mcfd.

## 6.1 Drilling Operations

The BDM/CWV/DOE Test Well No. 1, API Permit No. 47-081-0912, was drilled in Clear Fork District of Raleigh County, West Virginia by American Energy Corporation Rig No. 5. The truck mounted rig has a National 600 draw works, Caterpillar 3408 475 hp engine, 104-foot telescoping steel mast and an air package consisting of three Leroi 750 cfm air compressors with 475 hp Detroit diesel engines.

### 6.1.1 Location Building

The original location for the well was selected on top of a 50-foot wide ridge, however, the location had to be moved 400 feet north down the hill to solve problems associated with a disputed lease boundary. The new location was on a sharp narrow ridge and the actual surface elevation had to be excavated 5.3 feet so the surface elevation listed on the permit of 2,169.3 feet had to be changed to 2,164.0 feet. The location completed was 90 feet wide (including 25 feet of fill material on either side of the bedrock) and 150 feet long. The rig was set up lengthwise on the location to insure that the rig and drill string tubs were on bedrock. Figure 6.1.1 shows the location of the rig and supporting drilling equipment on the location. The 1,500-foot road to the location was very steep reaching grades of more than 20 percent in several places as it climbed more than 330 feet in elevation.

### 6.1.2 Drilling to Coalbed Core Point

Drilling operations on the test well began at 5:00 PM on April 30, 1991 with the drilling of the rat hole and drilling of the 17-1/2" conductor hole. A thirty-one-foot joint of 13-3/8" conductor casing was set and drilling of the 11-3/8 inch surface hole down to the Beckley Coal core point was initiated at 11:00 PM. A total of 310 feet of hole was drilled during the first twenty-four hours of drilling operations (See Daily Drill Report in Appendix 14.6.B). Another 320 feet of hole was drilled on the second day, with the core point being reached on the third day of drilling. The correct core point was missed because the coal was encountered over 30 feet higher than projected causing most of the coal to be drilled before drilling could be halted. No coal cuttings had been observed on the surface, however, a faster rate of penetration had been observed which was a definite indication of a soft formation being drilled. When the drilling rate of penetration dropped from two minutes per foot to 30 seconds per foot, an examination of the cuttings revealed only black shale. Because air-drilling often

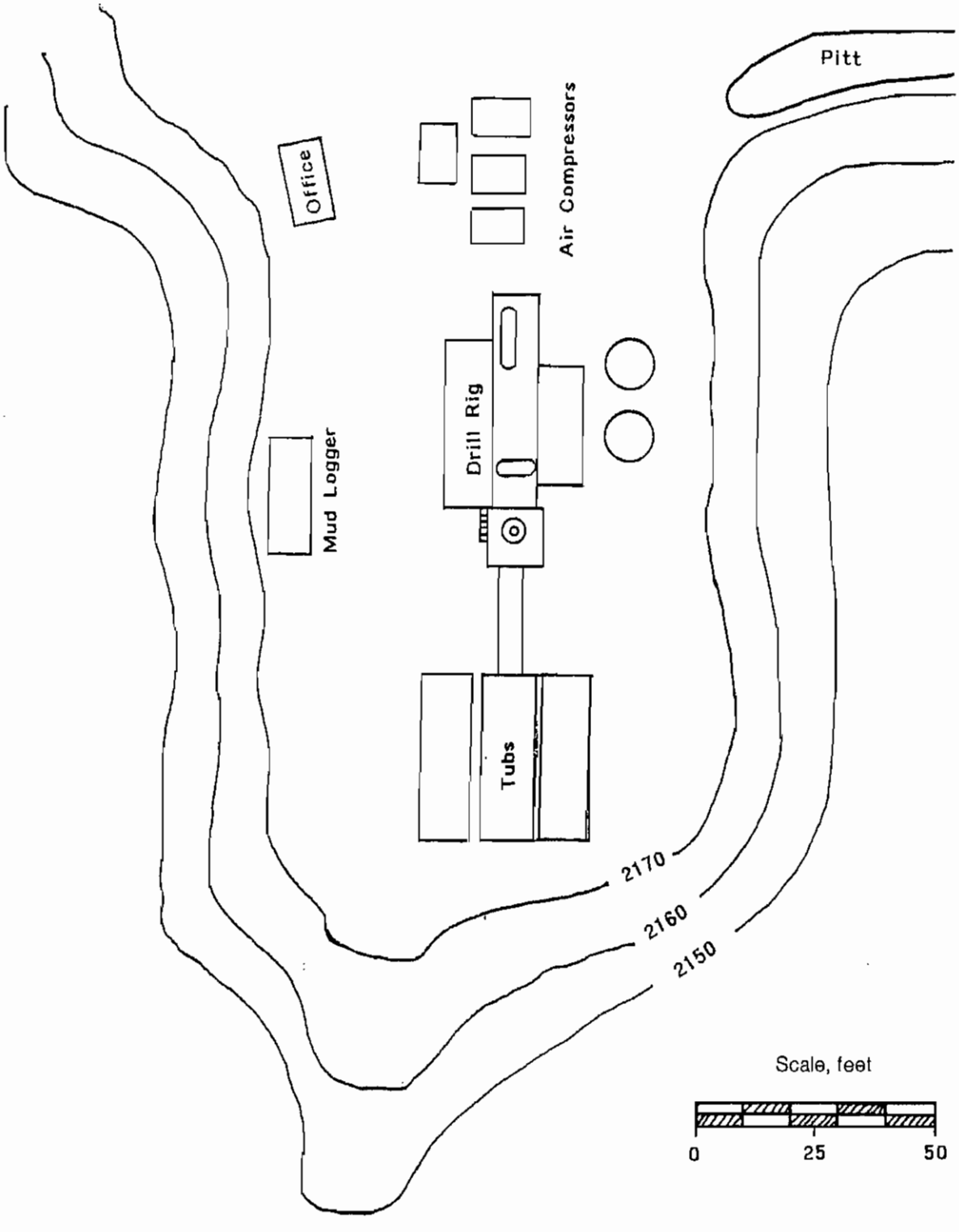



Figure 6.1.1 - Location Scematic of the Drill Rig and Supporting Drilling Equipment

causes coal to be ground to a fine powder making the cuttings very difficult to see, it was decided to initiate coring operations in case coal had been encountered. It was later learned that the upper part of the Beckley Coal already had been drilled and only the lower 1-1/2' of the coal was cored. Details of the coring operations are discussed under Section 6.2.

Because the apparent differences in the projected and actual tops of the Beckley Coal, the core point for the Pocahontas #4 and #3 coals was re-evaluated on-site. The results are presented in Table 4.1 which shows the original projection of coal tops, the revised and the actual tops recorded.

After core run Number 4, which included the Pocahontas #3 coal, was completed, a pocket was drilled to 1,295 feet so that water produced from the three potentially productive coalbeds could be collected and pumped out. Total depth according to the logger of the 10-5/8" hole was 1,288 feet, or 1,278 feet when corrected to ground level.

### 6.1.3 Drilling Operations Below Coalbeds

After the open-hole logging operations had been completed (see details in section 6.3), the 8-5/8" casing was set and cemented in place (see Chapter 7 for details). Drilling of the deeper hole looking for other pay zones was initiated by drilling out of the cement and guide shoe with a 7-7/8" bit. This section of the drilling operations was without incident. The 1,700 feet of hole was drilled in forty hours. This is an average rate of penetration of 42.5 feet per hour of drilling operation. This rate of penetration allowed completion of drilling operations two days faster than projected as shown in Figure 6.1.2.

Upon reaching the planned TD of 2,995 feet, drilling was halted and the 7-7/8" open hole was logged and the 4-1/2" casing installed. Details of logging and casing operations are presented in later sections. Drilling operations were completed at 5:30 AM on May 7, 1991.

## 6.2 Coring Operations

Core point for coring operations was to be 815 feet, or about 15 feet above the projected top of the Beckley Coal at 829 feet. This top was based on a refined map of structure on the Beckley Coal using corehole data provided by New Beckley Mining Corporation. The Beckley Coal was actually encountered at a depth of 791 feet, more than thirty feet higher than projected (see Table 6.4.1). As a result, the drill bit had penetrated five feet of the coal before drilling could be halted. In fact, because there was no evidence of coal in the cuttings, it was uncertain that a coal had been drilled. It seemed equally possible that the formation might be a soft organic shale, but it was decided to core anyway to be sure.

Only 1-1/2-foot of shale and coal was recovered in the core, so based on the possibility that this might be a rider coal above the Beckley seam, a second core run was made. This run failed to find any coal, so coring operations were halted on the likelihood that the Beckley Coal had been missed. While examining nearby coal corehole logs, a top for the Pocahontas #6 coal was projected at 965', and it was decided to try and recover a sample of this coal.

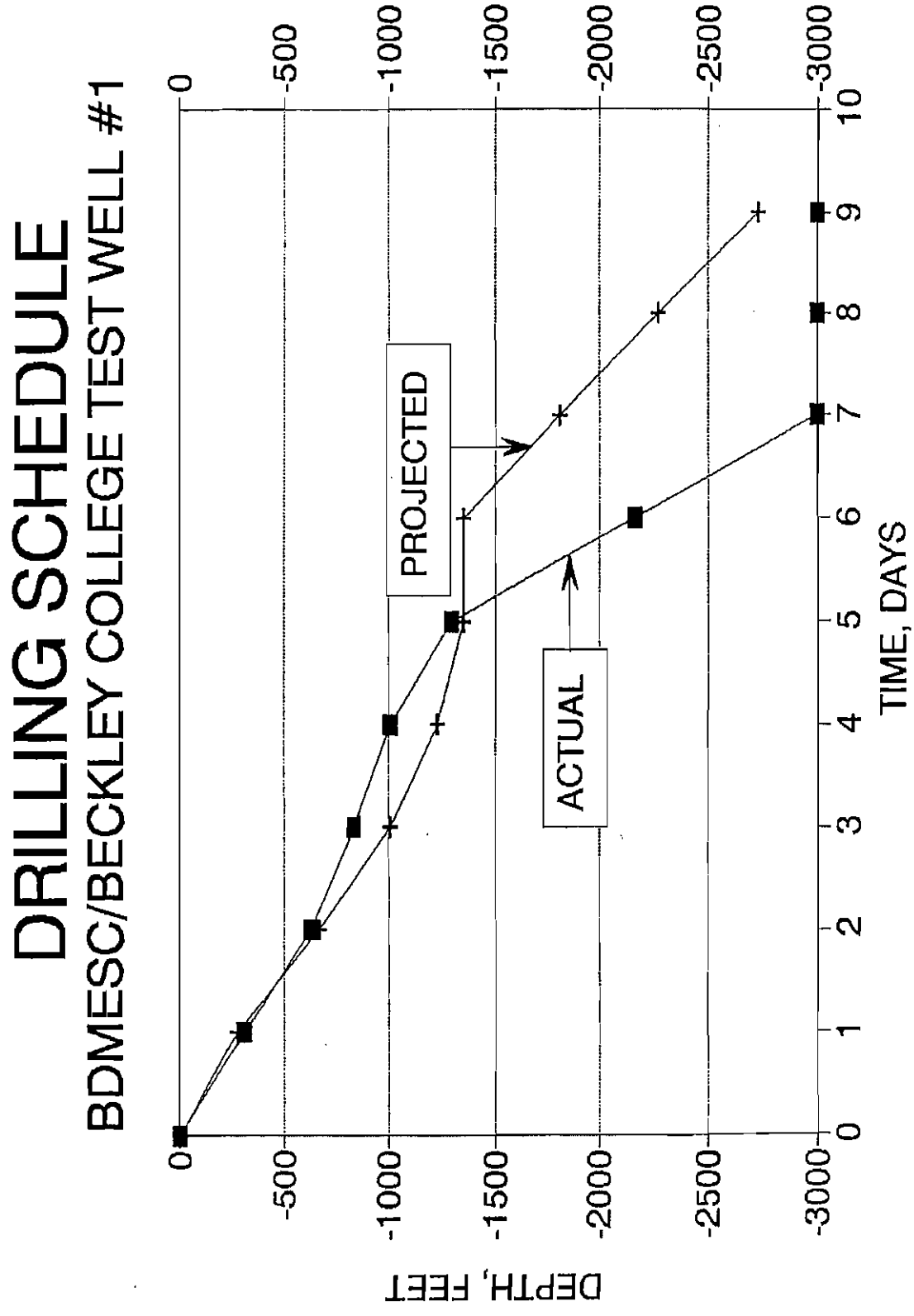



Figure 6.1.2 – TW-1 Actual Drilling Rate Much Better than Projected; 42.5 feet per hour versus 18 feet per hour During Drilling Operations Below the Coal Zones

No coal appeared to have been encountered while drilling to and through the projected core point. Core run Number 3 was made between 988 and 1,009 feet in an attempt to retrieve coal samples from any of the Pocahontas coals that might be present. No coal was recovered after twenty-one feet of drilling, so coring operations were again halted. When no Pocahontas #6 coal was encountered, the core hole data were again reviewed and the Pocahontas #4 was projected at 1043'.

After reaming the hole, drilling to the projected core point was resumed. It was decided to try and core both the Pocahontas #4 and #3 coals in the same run, the latter coal being expected at a depth of 1,053 feet. Drilling was continued until a drilling break was encountered at 1,076 feet'. The drill string was tripped out of the hole, the core barrel was placed on the drill string, and pipe was tripped back in the hole. Coring operations continued until 29 feet of formation were cored, coring well below the bottom of the Pocahontas #3 coal (12 feet).

Upon recovery of the core barrel and removal of the core, it was determined that three feet of Pocahontas #4 coal and four feet of Pocahontas #3 coal had been recovered. These coal samples were immediately placed in two-foot-long canisters for outgassing and desorption testing.

It proved to be very difficult to accurately project the tops of the various coal beds in this area using conventional geologic techniques. This is due to the fact that the depositional environment is deltaic with rapid changes in elevation occurring within short lateral distances. Most coring for coal data in this area is done by core drilling from the surface down to and through the coals of interest.

## 6.3 Logging Operations

Drilling plans called for logging the hole, both shallow and deep, with the same logging suite of gamma ray, lithodensity, dual induction, epithermal neutron, and video camera log of the borehole.

### 6.3.1 Shallow Logging Operations

After the borehole had been reamed from 7-7/8" to 10-5/8 inches and the wellbore cleaned by circulating air for twenty minutes, the drillstring was tripped out of the hole and the video camera inspection of the shallow borehole down to 1,292 feet was accomplished. Several fractures were noted and there were shallow fractures where water was flowing out of and into the wellbore.

When the video borehole survey was completed, the geophysical logs were run in two runs. The first run was gamma ray, lithodensity, temperature, and epithermal neutrons. The second run was to record the formation resistivity with a dual induction - later log. A computer analysis was run on the log data to determine gas and water saturation in the coals and sandstones. Shallow logging operations started at 6:00 am on May 4, 1991, and were completed at 6:00 PM on May 4, 1991.

### 6.3.2 Deep Logging Operations

Upon reaching TD of 2,995 feet at 5:20 am on May 7, 1991, the hole was cleaned for logging. Logging operations started at 7:00 am with a run of the video camera. Geophysical logging operations started at 11:15 am with Gamma Ray-Sidewall Neutron Porosity-Dual Induction (GR-SNP-DI) tool being run in the hole. The second run was made with a Gamma Ray, Lithodensity, Temperature tool combination. Deep logging operations were completed at 6:15 PM.

### 6.3.3 Cased Hole Logging Operations

After cementing operations were completed, the well was shut-in to let the cement set for several days. A cement bond, casing collar locator, and correlation gamma ray log was run on May 15, 1991.

On May 22, 1991, a cased hole unit correlated the Gamma Ray and CCL depths of a short casing joint and perforating of several zones in the Big Lime section was accomplished with a select five perforating gun.

On May 28, 1991, a cased hole unit set a drilled bridge plug at 2,801.7 feet and then made a second run to perforate the Ravencliff sand section before being foam fraced.

After cleanup of the frac jobs and setting another drillable plug above the Ravencliff sand, the 4-1/2" casing was removed at the left right nipple and a cement bond log, casing collar locator and correlation gamma ray log was run inside the 8-5/8" casing to determine where the slots should be cut before stimulating the coalbeds. This concluded cased hole logging operations on the well.

## 6.4 Cementing and Casing Operations

### 6.4.1 Casing Operations

Following the Logging Operations on the shallow section on TW-1, a 1,241.4 feet of 23#/ft, 8-5/8" casing was set and cemented to the surface. Three cementing baskets were run along with the 8-5/8" casing; two baskets above the Beckley Coal Seam, and one basket above the Pocahontas #3 Coal Seam. A total of six centralizers were used when running the 8-5/8" casing.

On May 7, 1991, 2,972 feet of 10.5#/ft, 4-1/2" casing were run to the surface with ten centralizers placed at various points along the 4-1/2" casing (Appendix 14.6.E). A 14.8 feet pup joint was placed above the fourth joint from bottom (at a vertical depth of 2,840.5 feet). A left-right nipple was placed at a depth of 1,236.1 feet (approximately above joint #40), to help retrieve the 4 1/2" casing from that point to the surface when stimulating the coal zones.

### 6.4.2 Cementing Operations

#### 6.4.2.1 Aquifer Protection Casing String

In accordance with State of West Virginia Oil and Gas Regulations, aquifers and coal seams must be isolated by a separate string of casing cemented all the way to the surface to prevent migration of fluids from one level to another.

A string of 1,241 feet of 8-5/8" casing was cemented in place with 350 sacks (413 cubic feet) of Class A cement containing 2% calcium chloride with an average density of 15.6 lbs/gallon. Water was circulated to the surface to clean up the hole and eliminate air pockets and then the cement was pumped at a rate of 5 barrels per minute. The plug was seated with 700 psi pressure in the cement shoe after 74 bbls of cement had been pumped. The cement was preceded by 15 bbls of gel followed by a 10 bbl water spacer.

6.4.2.2 Production Casing String

The 4-1/2" production casing was cemented in place with 325 sacks (384 cubic feet) of Class A cement containing 2% calcium chloride. The 68 bbls of 15.6 lb/gallon cement slurry was pumped at 4 bbls per minute. The latch down plug was set in the shoe with 1,200 psi pressure and held for 1 hour before being released. Good cement was backed up to a depth of 1,475 feet according to the cement bond log. This is 240 feet below the right nipple placed in the drill string at 1,235 feet, and just above the bottom of the 8-5/8" casing string. The figure of 10% excess cement over the volume calculated to fill the annular space was a little short in reaching the target depth of 1,300 feet.

## 6.5 Stimulation Operations

### 6.5.1 Pre-Stimulation Activities

Pre-stimulation activities consisted of cased hole logging, spotting acid, perforating, and breaking down the perforations in the case of the Big Lime. For the Ravencliff, it involved setting a drillable bridge plug, spotting acid, and perforating. The following is a more detailed discussion of these operations.

### 6.5.2 Big Lime Perforation

A Gamma Ray (GR), Cement Bond Log (CBL), and a Casing Collar Log (CCL) were completed in the 4 1/2" cased hole section of TW #1 enabling BDMESC to correlate the depths of shots with the perforating tool. The tool was run into the hole and correlated with the bottom of the pup joint. When this was done, BDMESC determined that the correlation was off by two feet. In order to correlate with the GR-CCL, the tool was pulled out of the hole and the depthometer was reset to the pup joint's correct depth. Once the tool had been calibrated, it was lowered back into the hole.

At a depth of 2,860 feet, a striplog was run showing the locations of the collars for correlating the shooting depth. The results of the striplog showed that the depth needed to be corrected by one foot. After correcting the depth and recorrelating the tool, the depth was off by a half-foot. The tool was corrected and recorrelated. When the tool was checked again, the calibration showed the tool to be properly depth corrected.

Three hundred gallons of 15% HCl was pumped into the hole before perforating started. The first 10-shot gun was fired as single shot select fire points and was moved after each shot until all 10 shots were fired. When all shots were fired, the gun was pulled out of the hole. The gun was checked to ensure each shot had gone off. Once checked, the second gun was loaded and dropped into the hole. Once again, the gun had to be corrected to a half-foot. When depths were correlated, the gun was moved to the 11th shot depth, fired, and pulled to the next point. All 10 shots were fired in this manner. A small flow of gas was noted after perforating was completed.

### 6.5.3 Big Lime Breakdown and Ball Out

Because of the large distances between porous zones to be stimulated in the Big Lime, it was decided to breakdown each perforation to make sure it would take fluid during stimulation. The following procedure was used during the breakdown and ball out activities.

A pressure test was made on the surface pipe to 2,500 psi. Afterwards, the 4" gate valve was opened and water (40 bbls) was pumped into the pipe until it was full. Next, a sequence consisting of four bbls of acid being pumped followed by dropping of three balls until a total 42 balls were dropped. Once all 42 balls had been dropped, water, in place of acid, was pumped into the hole. During this operation, the formation was observed to break down at 1,720 psi.

Approximately one minute after all the balls (42) had been dropped, the pressure soared from 650 psi to 2,950 psi, indicating ball-out had occurred. Once ball-out was reached, the well was surged to remove the balls from the perforation holes. There were 18 bbls of acid in the pipe which was removed by circulating water through the pipe at 5 bbl/min. Once the acid was circulated out of the hole, tools were lowered into the hole to ensure that each ball had been dislodged from the perforation hole.

### 6.5.4 Big Lime Fracture Treatment

Using nitrogen gas and 4000 gallons of 15% hydrochloric acid, 12,000 gallons of 70-quality foam was generated and pumped at 15 bbl/min (630 gal/min) into the prepared perforations. Perf-balls were dropped to insure that all perforations were treated. Half way through the job, 6 perforation balls were dropped; then three quarters of the way through the job, 6 more perforation balls were dropped; and pumping was continued until all of the foamed acid had been displaced. Once this was accomplished, 70 gals. of water were pumped into the well to displace the 70-quality foam beyond the perforations.

The job went nearly as planned. At a rate of 16 bbl/min, 70-quality foam was pumped into the well. After all 12 perforation balls were dropped, the rate was dropped back to 14 bpm because the acid pump was running roughly. Near the end of the frac job, there was a little more trouble with the acid pumper but minutes later the foamed acid frac was complete and

we switched to pumping water. 70 bbls of water was pumped into the hole to displace the 70-quality foamed acid beyond the perforations. The ISIP and 15 min. SIP were recorded as 1,713 psi, and 1,613 psi, respectively. Figure 6.5.1 presents a pressure time plot for the stimulation.

### 6.5.5 Ravencliff Perforation

The Ravencliff formation was perforated in the same manner as the Big Lime. 20 perforations were made from 1,670 feet to 1,705 feet by measuring up from the pup joint. Note: the retrievable bridge plug was set at 1,730 feet. 100 gals of 15% acid was spotted into the hole to aid in cleaning out the perforations. Each of the 20 shots were made on target. A stronger flow of gas was noted after perforating the Ravencliff than noted after the Big Lime and was estimated at 20 mcfd.

### 6.5.6 Ravencliff Fracture Treatment

The planned stimulation for the Ravencliff was to pump 25 bbls of water at 10 bbl/min first, and then to increse the rate to 15 bbl/min to breakdown all perforations. This was then to be followed by 4,000 gallons of 75-quality foam as the pad stage.

Next, the following stages were to be pumped into the hole, sequentially:

Stage 2 4000 gals. 75-Q foam with 1 lb/gal 80/100 sand.
Stage 3 5500 gals. 75-Q foam with 2 lb/gal 80/100 sand.
Stage 4 1000 gals. 75-Q foam pad with 20/40 sand.
Stage 5 8000 gals. 75-Q foam with 1 lb/gal 20/40 sand.
Stage 6 8000 gals. 75-Q foam with 2 lb/gal 20/40 sand.
Stage 7 8400 gals. 75-Q foam with 2.5 lb/gal 20/40 sand.
Stage 8 4000 gals. 75-Q foam displacement

After pumping the job, the well was to be shut in for 15 minutes to monitor the pressure. The total estimated pumping time including breakdown was just over an hour.

As the frac job began, it was noticed that the digital rate meter was not functioning properly. Although the clean and dirty rate monitors were not functioning properly, the pressure and density monitors did work. The strip chart was watched to ascertain the dirty rate.

The lines were pressure-tested to 3200 psi with no leaks. To fill the hole, 12 bbls of water was pumped into it and breakdown was initiated. The formation broke at 1,350 psi bottom hole pressure (620 psi surface pressure). The planned frac program was followed closely and although the digital rate meter did not operate properly, the frac job was successfully completed. Foam quality ranged between 65 and 75. Figure 6.5.2 presents the pressure versus time plot for the frac job.

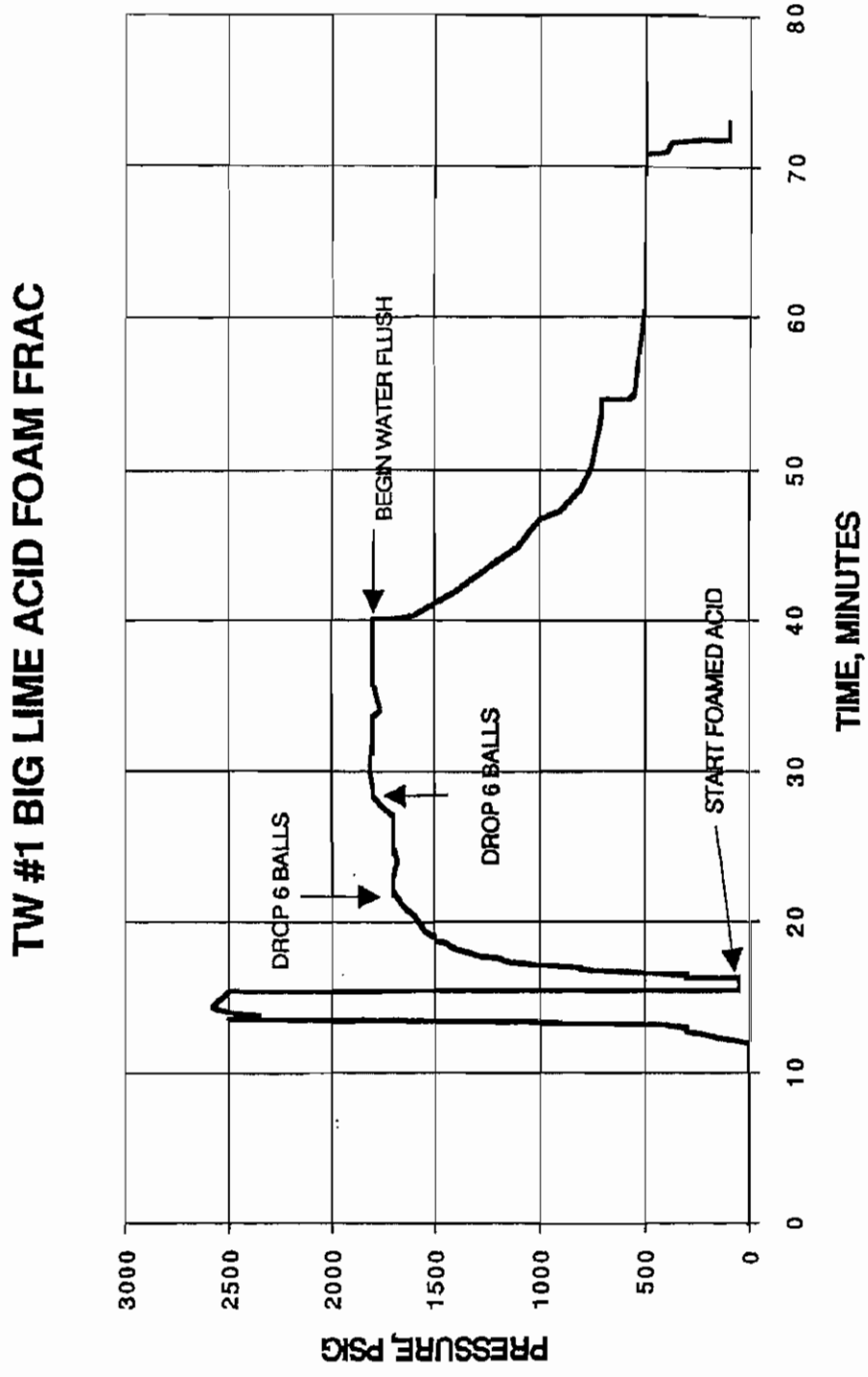



Figure 6.5.1 – Pressure versus Time Plot for Foamed-Acid Frac Treatment of the Big Lime Formation in TW-1

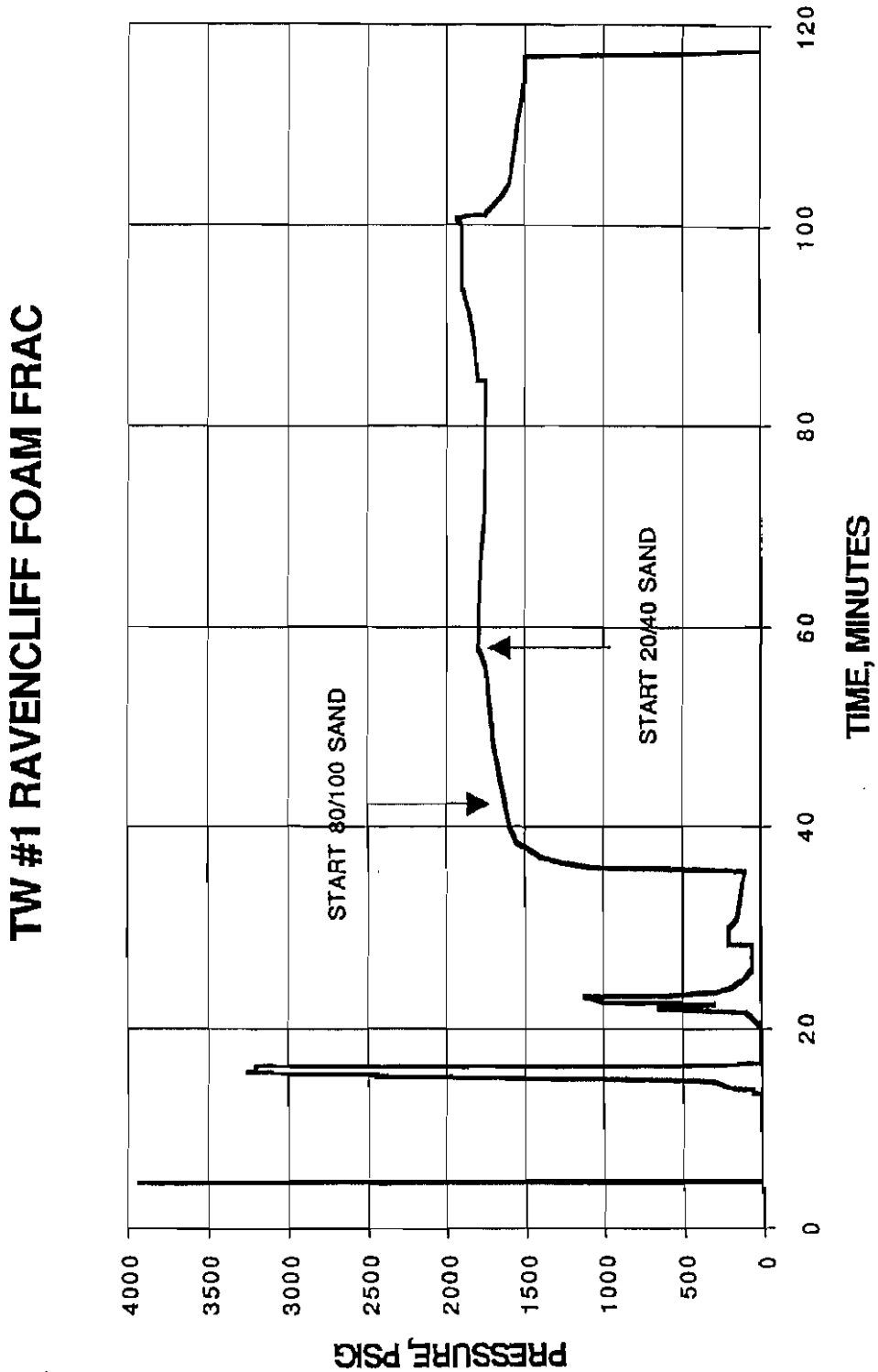



Figure 6.5.2 - Pressure versus Time Plot for the Foam-Frac Treatment of the Ravencliff Sandstone in TW-1

### 6.5.7 Coal Bed Stimulation Targets and Design

Upon the successful stimulation of the Big Lime and Ravencliff formations in TW-1, a temporary plug was set in the 4-1/2" casing to isolate these zones from the shallow coal seams to be stimulated. Approximately 1,200 feet of the 4-1/2" casing was temporarily removed from the well to allow access to the coal seams behind the 8-5/8" casing.

Four coal seams were encountered in the wellbore of the test well: the Sewell, Beckley, Pocahontas #4, and the Pocahontas #3 coals. These four coals are found at depths of 544, 791, 1,074, and 1,091 feet, respectively. In accordance with the screening criteria, the Sewell coal was determined to be too thin and shallow to be considered for stimulation and production. The remaining three were approved as suitable targets for stimulation operations based on mud log and geophysical log analysis.

Mr. Fred Skidmore, a consultant with recent successful experience in the area, was consulted concerning plans for stimulation. Frac designs which were considered included high-viscosity fluids with proppant, nitrogen-foam fluids with proppant, nitrogen with no proppant, and Mr. Skidmore's system using ungelled (low-viscosity) water with and without proppant in alternating stages.

Mr. Skidmore's design was selected and included the following key elements:

(1) Access to the formation by jetting slots in the casing.
(2) Conducting injectivity test in the coal to determine pumping rates.
(3) Use of clean untreated water as the transport fluid.
(4) An initial pad volume of 20% of total volume.
(5) Alternating equal volumes of sand laden fluid and pad (water only).
(6) Pump job at the highest rate possible to prevent screenout.

The stimulation planned for the Poca #3 and #4 coals (stimulated as a single zone) was to pump the job at 40 bbls/min starting with a 300-bbl pad of clean untreated water and to displace 15,000 lbs of 80-100 mesh sand followed by 40,000 lbs of 20-40 mesh sand using alternating stages of clean and sand-laden water. Flowback after the stimulation treatment was to be at a controlled rate to prevent production of sand back out of the formation. A similar design was proposed for the Beckley coal.

### 6.5.8 Design Execution

The stimulation of the Poca #3 and #4 coals was executed as designed. A special report on the stimulation operations is presented in Appendix 14.6.F.

#### 6.5.8.1 Formation Access

Access to the coal seams for stimulation was accomplished by abrading slots in the 8-5/8" casing with high-pressure sand-laden jets of water. A cement Bond Log with correlation Gamma Ray and Casing Collar Locator Log was run and correlated with the open-hole Gamma Ray log to determine the depths of the coal seams in relation to the 8-5/8" casing. The

slotting was started at the bottom of the interval and moved upward about 4 inches at a time upon the occurrence of a sharp drop in the injected water pressure, indicating the penetration of the casing and cement sheath. This processes was repeated until the intire selected interval was completed. Approximately three hours and forty-five minutes of high pressure (2500 psi) jetting was required to make two opposing 4-foot slots in the Pocahontas #3. The same process was repeated for the Pocahontas #4 coal.

6.5.8.2 Injectivity Testing

After slotting of the casing was completed, the well was cleaned up by backwashing down the 8-5/8" casing and back up the 2-3/8" tubing. This operation took about 90 bbls of water to complete at a depth of 1,100 feet. The injectivity test was pumped down the 8-5/8" casing. Starting with a rate of 0.25 bbls/min of water, pumping continued until the predetermined pressure limit (1800 psi) for the test was reached. Pressure falloff was watched as an indicator of permeability. After 15 minutes with no pressure decline, pumping was resumed. After an increase of only 50 psi pressure, the formation began to take water very slowly. The test continued by increasing water injection to the following rates: 0.5, 1, 2, 4, and 7.5 bpm.

The same injection test procedure was used on the Poca #4 coal. Top injection rate was approximately 7.8 bbls/min. This result indicated the Poca #4 coal was more permeable than the Poca #3 coal.

6.5.8.3 Stimulation Procedure

The Pocahontas coals were stimulated first. A retrievable bridge plug was set inside the 8-5/8" casing at a depth of 1,150 feet in preparation for the first stage of the operation. The casing opposite the coals was slotted by abrasive jetting and water was pumped slowly into the formation until breakdown occurred. The bridge plug was then moved up to a point just above the Poca #3 coal and the casing slotting process was repeated for the #4 coal. The Frac job was conducted the next day as planned with the exception that the designed maximum injection rate of 40 bpm could not be achieved (28 bpm was the highest rate obtained) so the job had to be scaled back accordingly. This resulted in less sand being injected than planned, but no screenout (sand-plugging) occurred. The well was flowed back slowly overnight and 350 bbls of frac water were recovered during this initial flowback period.

The retrievable bridge plug was then moved to a point above the Pocahontas coals at a depth of 850 feet, and the same process of slotting, injection testing, and fracturing was performed on the Beckley coal. The design rate of 40 bpm was achieved in this coal bed and the entire job was conducted as planned.

6.5.9 Results of Stimulation

6.5.9.1 Stimulation Fluid Recovery

After an initial flowback period which only lasted about 6 hours, the well had to be swabbed to remove the frac water. Approximately 350 bbls of water was produced back into the frac tanks during this initial flowback period. On the day following the frac job in the Poca #3 and

#4 coals, water recovery was halted so stimulation operations on the Beckley coal could be initiated.

After stimulation of the Beckley coal, the well was flowed back into the frac tanks to measure recovered volumes. The bridge plug was removed and all three coal seams were cleaned up together by swabbing through the 4-1/2" casing. During this initial clean-up period, 1,535 bbls of the 3,078 total bbls injected during testing and stimulation were recovered (Figure 6.5.3). This represented 49.85 percent of the water injected. The balance was left to be pumped out during production operations.

6.5.9.2 Gas Production

Minor gas production was noticed after the first day of swabbing. After more than 10 days of swabbing, a steady production of gas was noticed . The gas was measured several times and the rate recorded was 47,000 cubic feet per day. The gas was almost pure methane, and no odor could be detected by smelling the gas.

6.5.10 Analysis of Stimulation Operations

6.5.10.1 Pocahontas #3 and #4 Stimulation

The stimulation was conducted by pumping down the 4-1/2" casing while holding 1100 psi pressure on the annular space between the 8-5/8" and 4-1/2" casings. The formation had been fractured (pressure parted) during the injection test on the previous day. Top pressure for the job was set at 2500 psi. Analysis of the injectivity test indicated that ther could be difficulty in achieving design rates of 40 bpm and sand concentrations of 3 lbs/gal. This was indeed the case and the program had to be adjusted to accommodate the lower injection rates to prevent sand screenout of the job. Planned versus actual water volumes (slurry) injected are presented in Figure 6.5.4. The major volume change in stage #14 was necessary to prevent screenout when slurry concentration was increased from 1.5 lbs/gal to 2.0 lbs/gal sand (Figure 6.5.5). A summary by stage of the average values of casing pressure, injection rate, and slurry concentration is presented in Figure 6.5.6. Instantaneous shut-in pressure was 1193 psi, 15-minute pressure was 723 psi.

Modification of the design allowed successful completion of the stimulation. Seven thousand (7,950 lbs) pounds of 80/100 mesh sand was injected along with 30,050 pounds of 20/40 mesh sand for a total of 38,000 pounds of sand. Examination of the fluid being returned to the pit showed only traces of 80/100 mesh sand being produced.

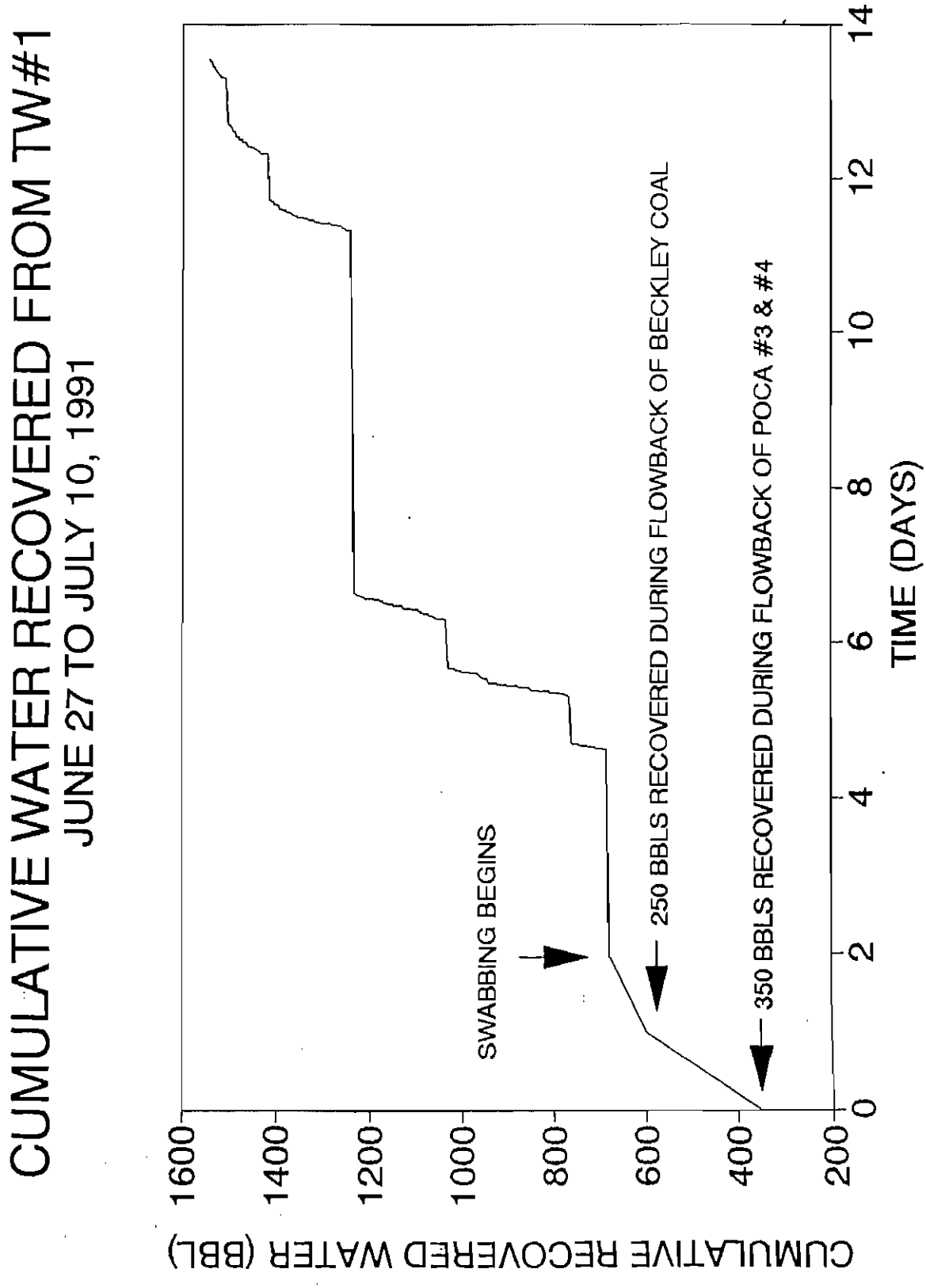



Figure 6.5.3 – Water Recovery After Stimulation of Coal Seams

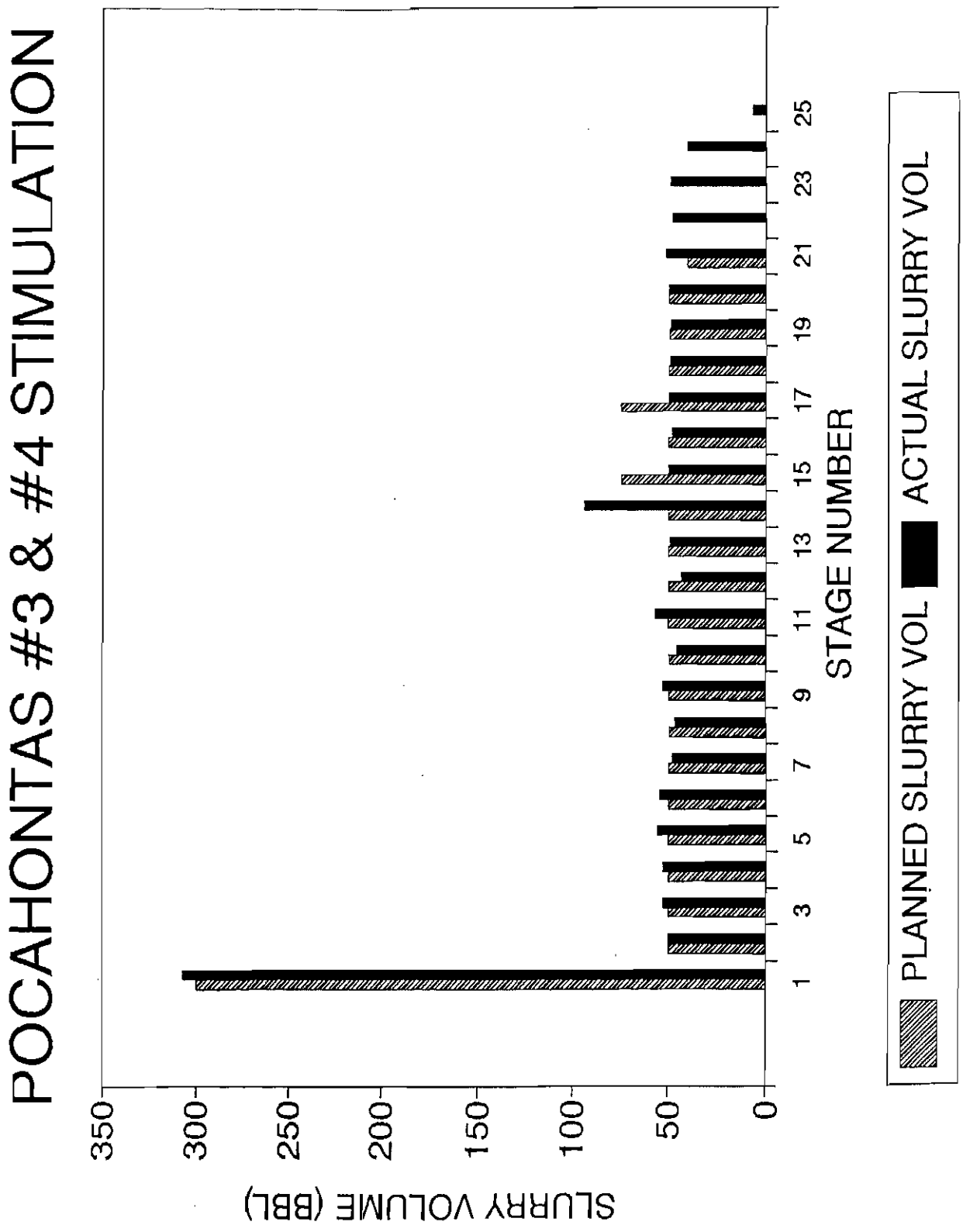



Figure 6.5.4. - Planned versus actual water volumes, Pocahontas #3 and#4 Stimulation

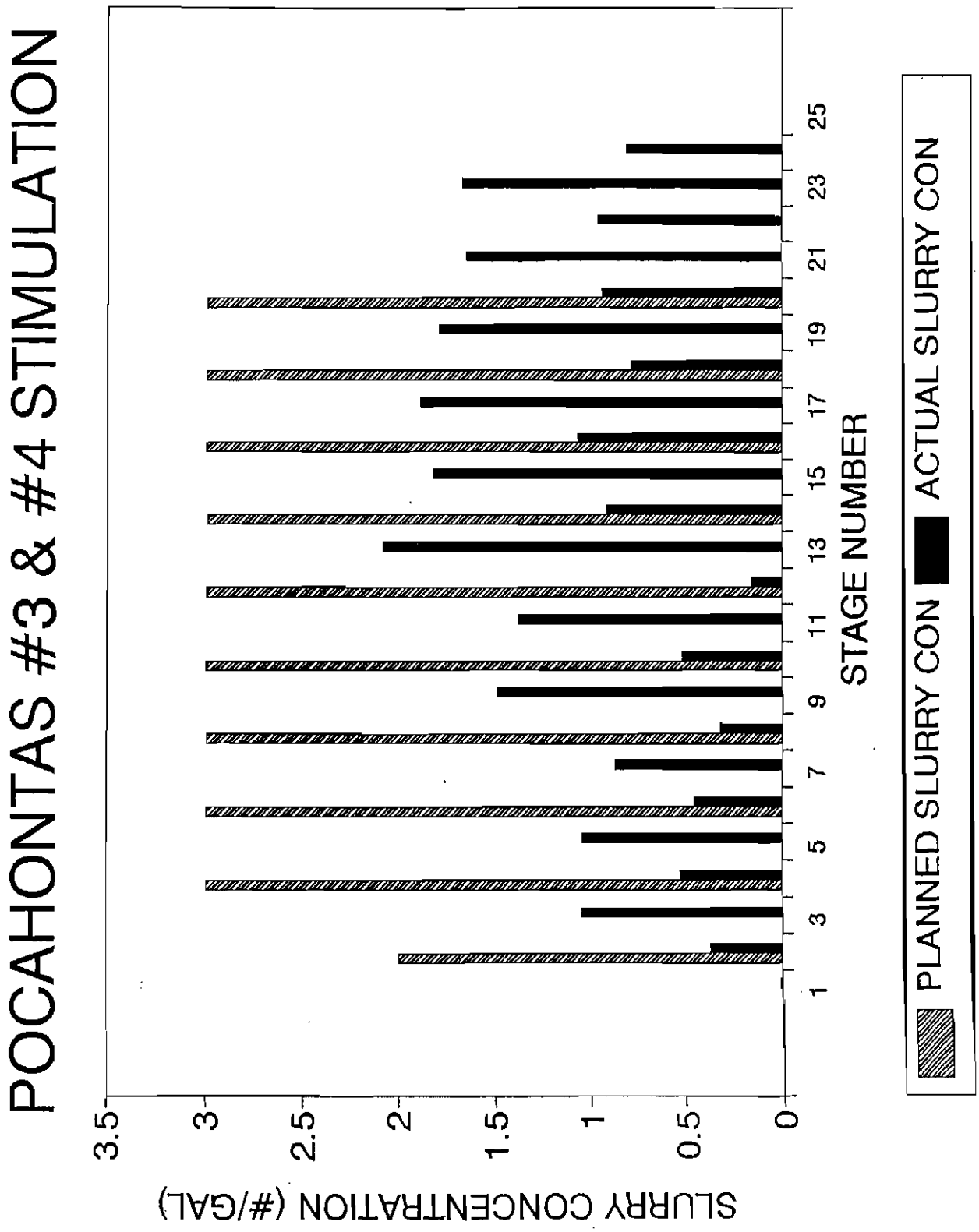



Figure 6.5.5 – Planned vs Actual Slurry Concentrations, Pocahontas #3 and #4 Frac Job

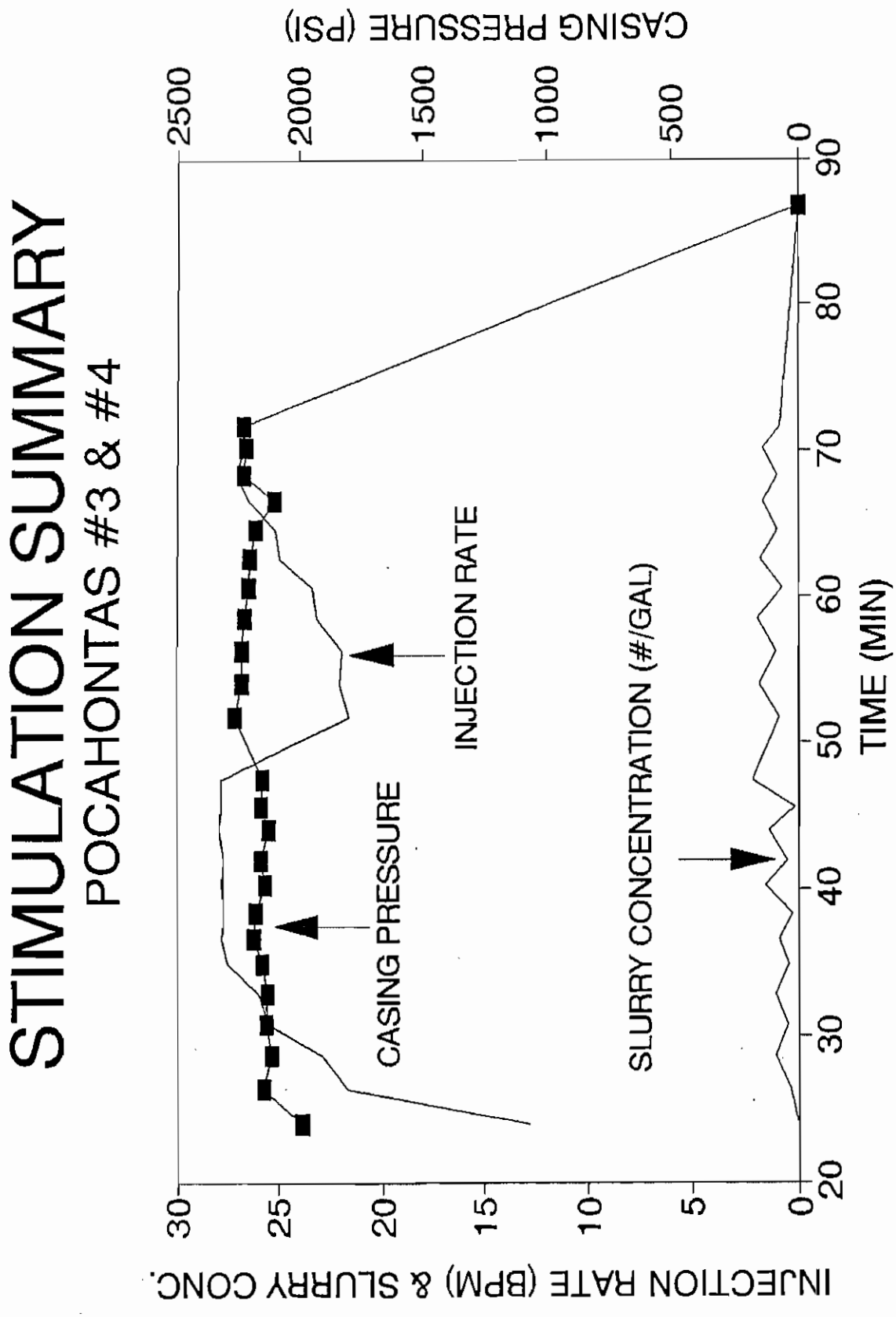



Figure 6.5.6 – Pressure, Rate, & Sand Concentration with Time, Pocahontas #3 and #4 Frac Job

6.5.10.2 Beckley Coal Stimulation

The stimulation of the Beckley Coal was performed in the same manner as with the Pocahontas coals, via the 4-1/2" casing. The Beckley seam treated at a much lower pressure than the Pocahontas coals. Top pressure encountered for this job was 1715 psi. The instantaneous shut-in pressure was 591 psi while the 15-minute pressure was 437 psi. Examination of Figure 6.5.7 shows that the actual frac job was executed as planned. There were some minor differences in slurry concentration (Figure 6.5.8) which was more a function of the equipment than any formation tendencies of the Beckley coal. A plot of the average values for casing pressure, injection rate, and slurry concentration is presented in Figure 6.5.9. In stage 11, it appears that a large fracture may have been encountered, lowering the fluid volume so rapidly that a screenout occurred. The pressure then built up until another fracture was opened (at 1715 psia) and the treating pressure followed the same pattern as it did in the earlier stages (1 through 10).

This stimulation was conducted almost in text book fashion. The screenout caused some concern, but coal seams have so many natural fracture paths that can be utilized that there is little threat to the success of the operation.

6.5.10.3 Analysis

Stimulations were very successful. Upon clean-out and recovery of 50 percent of the water injected, the well was making 47 mcfd. The only records of other stimulations completed in the area (about 7 miles away) was of a well whose top production was 37 mcfd at peak of production.

6.6 Summary

TW-1 was drilled, completed, and stimulated in accordance with the drilling plan. Coring operations on the Beckley Coal were not very successful because the coal was encountered much feet higher than projected from nearby wells and geologic data. Most of the coal was drilled through before the rig could be stopped. Coring of the Pocahontas coals was more successful. Coring operations are probably more cost-effective when smaller-diameter NX cores are taken from the surface down to and through the coal seams of interest.

Several gas shows were noted on the mud log of the well. These gas shows were used in conjunction with video logs and geophysical logs to select the zones to stimulate.

The Big Lime was perforated and fraced in five zones with a foamed-acid frac. The Ravencliff sand was perforated over a 35-foot interval and a 75-quality nitrogen foam frac conducted. The Big Lime had an initial open flow of 230 mcfd with a reservoir pressure of 280 psig. The Big Lime was producing 140 mcfd after flowing for 6 hours continuously. The Ravencliff sand had 85 psi pressure after a 67 hour pressure build-up test and open flow tested 81 mcfd. The Ravencliff was producing 63 mcfd after a 5-hour test.

The Pocahontas #3 and #4 coals were stimulated with 3,000 bbls of untreated water and 46,000 lbs of sand at 40 bbl/min. The Beckley coal was fraced in an identical manner with

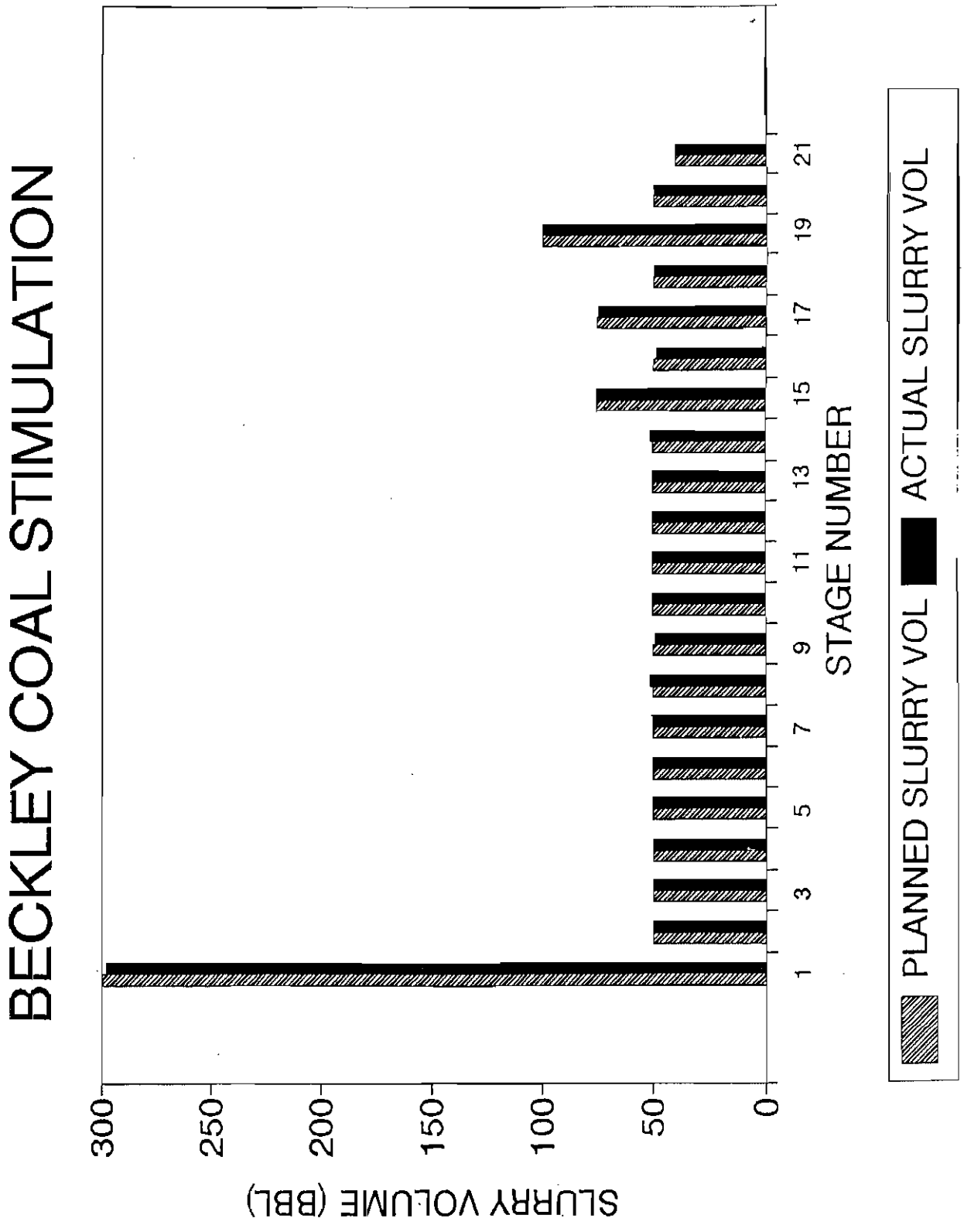



Figure 6.5.7. - Planned versus Actual Slurry Volumes, Beckley Coal Stimulation

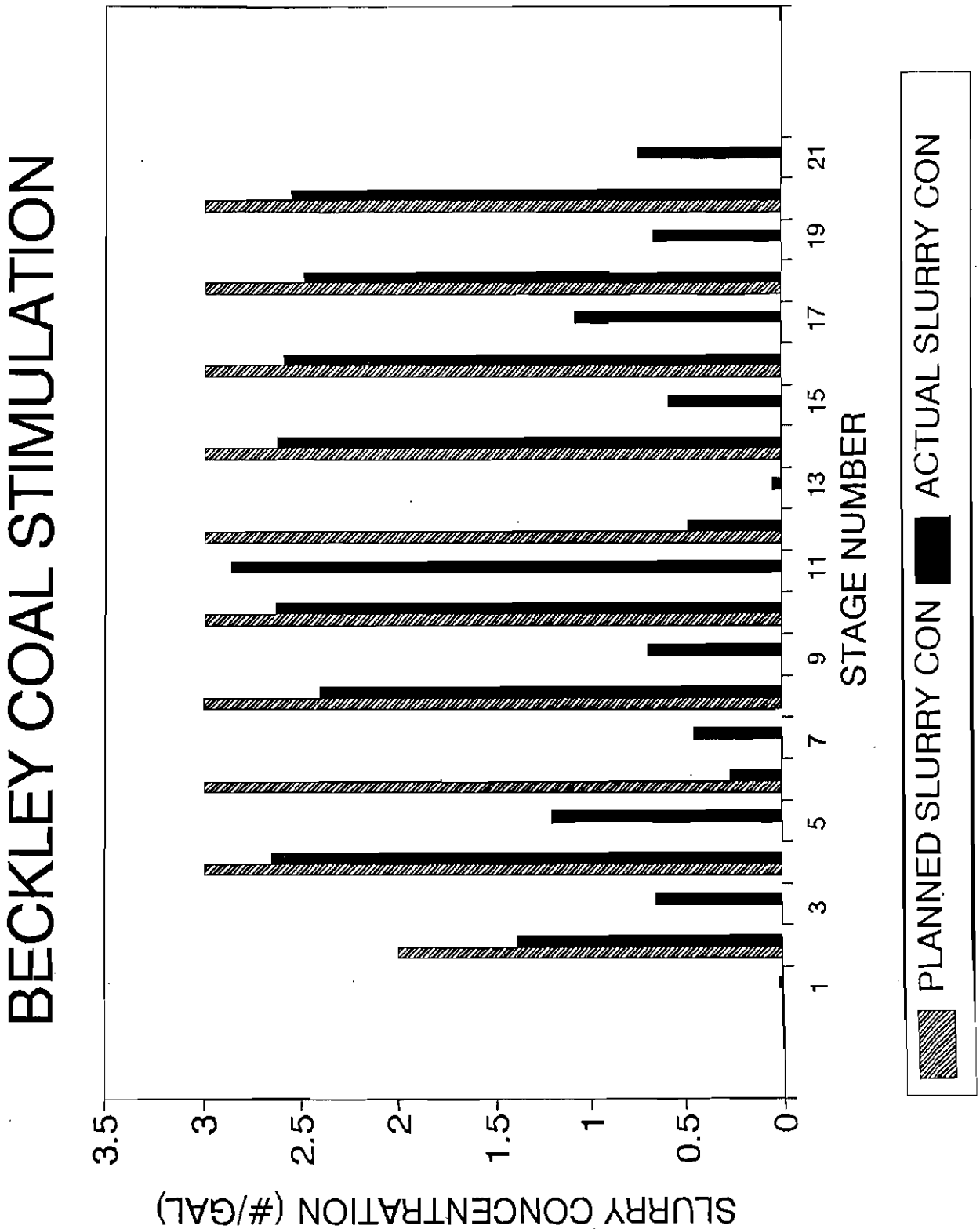



Figure 6.5.8. - Planned versus Actual Slurry Concentrations, Beckley Coal Stimulation

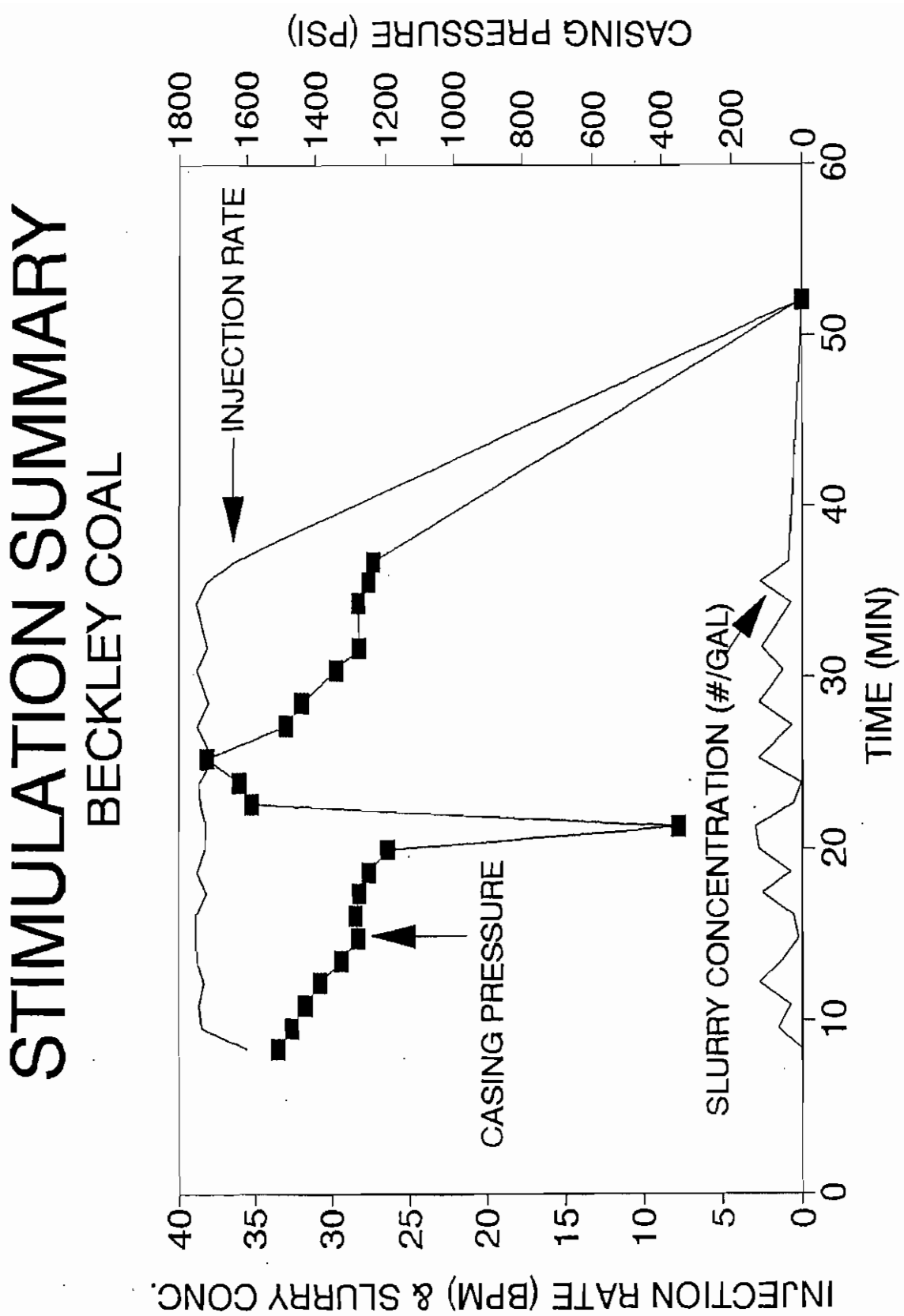



Figure 6.5.9 – Pressure, Rate, & Sand Concentration with Time, Beckley Coal Frac Job

1390 bbls of H2O and 70,000 lbs of sand. All three coals together produced 47 mcfd after 1,416 bbls of water had been produced or swabbed from the coals. A pump jack was installed on the well to pump water from the coalbed and allow the gas to flow. Early tests indicate 6 to 10 bbls water per day were likely to be produced while 40 to 50 mcfd of coalbed methane gas could be produced.

## 7.0 TEST WELL NO. 2 SUMMARY OF OPERATIONS

Test Well No. 2 (TW-2, API Permit No. 47-081-0924), located in Clear Fork District of Raleigh County, West Virginia, was spudded on November 12, 1991, after a seven-day location building effort and then drilled to a total depth of 3,248 feet.

Following the drilling operations, a set of open-hole geophysical well logs and video camera logs were run to determine and evaluate the potential productive zones. In addition, cased hole logs such as the Cement Bond Log (CBL), Casing Collar Log (CCL), and correlation Gamma Ray logs were run prior to perforating the casing or setting the bridge plugs.

After evaluating the well logs, selected target formations were treated using proved stimulation technologies.

### 7.1 Drilling Operations

The drilling operation on TW-2 was performed by American Energy Corporation Rig No. 5. The truck-mounted rig has a National 600 draw works, Caterpillar 3408-475 475-hp engine, 104-foot telescoping steel mast, and an air package consisting of three air compressors.

The well location, which was located in the crest of the ridge near the northwestern boundary of Southern Land's CF-8 tract, was cut and graded to form a drilling pad 210 feet long and 120 feet wide. The well road utilized an existing logging trail for approximately 300 feet, then climbed for 1,800 feet along the steep hillside reaching a surface well elevation of 2,224.4 feet

Drilling operations started at 7:30 PM on November 12, 1991, with the drilling of the rat hole and a 15" conductor hole. A thirty-foot 13-3/8" conductor casing was set and an 11" surface hole was drilled down to the Pocahontas #3 coal (see Daily Drilling Reports in Appendix 13.5). On November 15, 1991, the TD of the shallow hole was reached at a depth of 1460 feet. This included a 60-foot pocket so that water produced from the productive coalbeds could be collected and pumped out. The total depth of the 11" hole according to the logger was 1,460 feet (KB), which is 1,450 feet when corrected to ground level.

Prior to drilling below the coalbeds, open-hole geophysical well logs were run on the shallow section and the 8-5/8" casing was set and cemented in place.

Drilling of the deeper hole was initiated by drilling out the cement shoe with a 7-7/8" drill bit. A total of 1,788 feet of 7-7/8" hole was drilled in 43 hours at a rate of 41.6 feet per hour. Upon reaching a total depth of 3,248 feet, drilling was halted and the 7-7/8" open hole was logged and then cased with 4-1/2" pipe.

## 7.2 Logging Operations

Logging operations were conducted in three stages, shallow open-hole logging, deep hole logging, and cased hole logging.

Shallow hole logging was initiated following wellbore cleanup by circulating air for thirty minutes. The drillstring was tripped out of the hole and a video camera was used to inspect and evaluate the shallow borehole down to 1,460 feet. Several fractures and gas shows were noted and water was flowing into the wellbore in substantial amounts at 511 feet and 599.7 feet. The water level was detected at 950 feet the indicating a 510-foot water column. After completing the video borehole survey, the geophysical logs were run in two runs. The first run included the gamma ray, lithodensity, temperature, and epithermal neutron logs. The second run was to record the formation resistivity with a dual induction-lateral log.

Upon reaching TD of 3,248 feet at 7:00 am on November 18, 1991, the hole was cleaned and logged. A video camera survey and a set of geophysical open-hole well logs were run. The open-hole well logs included gamma ray, lithodensity, temperature, epithermal neutron, and dual induction.

After cementing operations were completed, the well was shut-in to let the cement set for several days. A cement bond, casing collar locator, and correlation gamma ray was run on the deep cased hole section prior to perforating the Big Lime and the Ravencliff.

## 7.3 Cementing Operations

Following the logging operations on the shallow section of TW-2, 1,409.5 feet of 32 #/ft, 8-5/8" casing was set and cemented to the surface using 450 sacks of class A cement with 3% CaCl2 and 0.25 lb Flake. The total slurry yield was 531 cubic feet at a yield of 1.18 cubic feet/sack. Two cement baskets were placed above the Beckley Coal to protect the Beckley seam from the pressure exerted by the cement column. In addition, a total of six centralizers were used when running the 8-5/8" casing.

After running 3,179 feet of 10.5 #/ft, 4-1/2" casing, the 7- 7/8" hole was cemented with 373 sacks of 50/50 POZ cement using 2% gel and 10 lbs. of salt. The cement shoe was set at 3137 feet and the 4-1/2" pipe was cemented to approximately 200 feet above the top of the Ravencliff formation which is located at a depth of 1,829 feet (GL). A total of 10 centralizers were placed at various points along the 4-1/2" casing with a Left-Right nipple (L-R) set on top of joint #43 to help retrieve the 4-1/2" casing from that point to the surface when stimulating the coal seams.

## 7.4 Stimulation Operations

Following the logging, casing, and cementing operations, BDM's geologists and engineers reviewed and analyzed the well logs to assess the potential productive formations for stimulation treatments. Based on all available data, BDM designed and executed the stimulation treatments for the Big Lime and Ravencliff formations.

### 7.4.1 Big Lime Treatment

The review of the geophysical well logs indicated that the lower section of the Big Lime had a high water saturation and therefore was potentially water-productive. On the other hand, the well logs indicated that the upper section of the Big Lime was a potentially gas productive zone. These two sections of the Big Lime were analogous to the Big Lime sections on TW-1 where the upper section was a more gas productive zone than the lower section, which was mainly water productive.

On January 23, 1992, the Big Lime was perforated and acidized. A total of sixteen perforations were placed in the Big Lime with one perforation per foot after spotting 500 gallons of 15% HCl.

A 3.125" select-fire gun was used to place the following perforations:

| Depth | No. of Shots |
|---|---|
| 2772.5'-2775.5' | 1 shot/ft = 4 shots |
| 2783.5'-2784.5' | 1 shot/ft = 2 shots |
| 2794.5'-2799.5' | 1 shot/ft = 6 shots |
| 3040.5'-3043.5' | 1 shot/ft = 4 shots |
| | Total = 16 shots |

Following the perforation of the Big Lime, a total of 500 gallons of 15% HCl was then pumped along with 30 perf-balls. The acid was displaced with 48.5 barrels of water and the well was then shut-in for the day.

The next morning on January 24, 1992, field activities were resumed. The fluid level was detected at 1,000 feet at 8:30 am. A total of 19.2 bbls of acid and water were swabbed using a workover rig, after which the well was flowed at a rate of 42 mcfd.

A 67-hour pressure build up test indicated a 500-psig reservoir pressure in the Big Lime compared to a 280-psig reservoir pressure in the Big Lime on TW-1.

Swabbing activities were resumed on Monday, January 27, 1992 to recover the remaining acid and water in place. A total of 11.5 bbls were swabbed during the day and an open flow measurement from the Big Lime indicated a production rate of 53.7 mcfd.

A drillable bridge plug was set above the Big Lime and below the Ravencliff to start the stimulation activities in the Ravencliff.

### 7.4.2 Ravencliff Treatment

After setting the 4-1/2" drillable bridge plug at 1,860 feet, the target zone of interest between 1829 to 1838 (GL) was spotted with 82 gallons of 15% HCl and perforated with 10 shots at a spacing of 1 shot per foot.

The following day, January 29, 1992, the frac company moved on location to pump a planned total of 25,000 gallons of 80-quality nitrogen foam and 40,000 lbs of sand (35,000 lbs of 20/40 mesh and 5,000 lbs of 80/100 mesh). A total of 372 mcf of nitrogen was pumped compressed to 634 scf/bbl. The total clean liquid volume pumped with the job was 142 bbls, including 10 bbls of water (as foam) used for flush. The maximum sand concentration was 3.0 lb/gallon and the overall pumping rate for the job was 20 bpm as designed. After testing the surface equipment at a pressure of 3800 psig, formation breakdown was recorded at 1900 psig. The average treating pressure was 2047 psig and the maximum treating pressure was 2170 psig. The Initial-Shut-In-Pressure (ISIP), 5-minute SIP, 10-minute SIP, and 15-minute SIP were recorded at 1850, 1630, 1610, and 1570 psig, respectively. Based on the 10-minute SIP of 1610 psig and the top perforations at 1,829 feet, the frac gradient was calculated to be 0.88. Figure 7.4.1 shows the complete pressure history of the Ravencliff frac job. As soon as the frac company rigged down their equipment and moved off location, a swabbing unit was moved on to start the post-frac cleanup operation.

## 8.0 TEST WELL NO. 3 SUMMARY OF OPERATIONS

Test Well No. 3 (TW-3, API Permit No. 47-081-0925), located in the Clear Fork District of Raleigh County, West Virginia, was spudded on October 29, 1991, and drilled to a total depth of 3,193 feet. Following the drilling operations, geophysical well logs and video camera logs were run in the hole to determine and evaluate the potential productive zones. The well was then cased and the productive horizons were treated using proven stimulation technologies.

### 8.1 Drilling Operations:

The drilling operation was performed by American Energy Corporation Rig No. 5. The truck-mounted rig had a National 600 draw works, a Caterpillar 3408-475 engine, a 104-foot telescoping steel mast, and an air package consisting of three Leroi 750-cfm air compressors with 475-hp Detroit diesel engines.

The TW#3 well location, located on the crest of a ridge near the northeastern corner of Southern Land's CF-8 tract and at a surface elevation of 2,220.6 feet, was cut and graded to form a drilling pad 150 feet long and 100 feet wide. The well utilized 1,625 feet of existing lease roads, with approximately 950 feet of additional road constructed along the crest of the hill.

Drilling operations were performed in two separate stages; the Shallow Hole drilling, from the surface to a depth of 1,396 feet; and the Deep Hole drilling, from 1,396 feet to a total depth of 3,193 feet.

Shallow hole drilling on TW-3 started at 3:00 PM on October 29, 1991, with the drilling of the rat hole and the 15" conductor hole in which a 30-foot 13 3/8" conductor pipe was set. An 11" hole, going through the Beckley and Pocahontas coal seams, was drilled to a depth of 1,396 feet in 58 hours (see Daily Drill Reports in Appendix 14.8.B). The Beckley coal seam

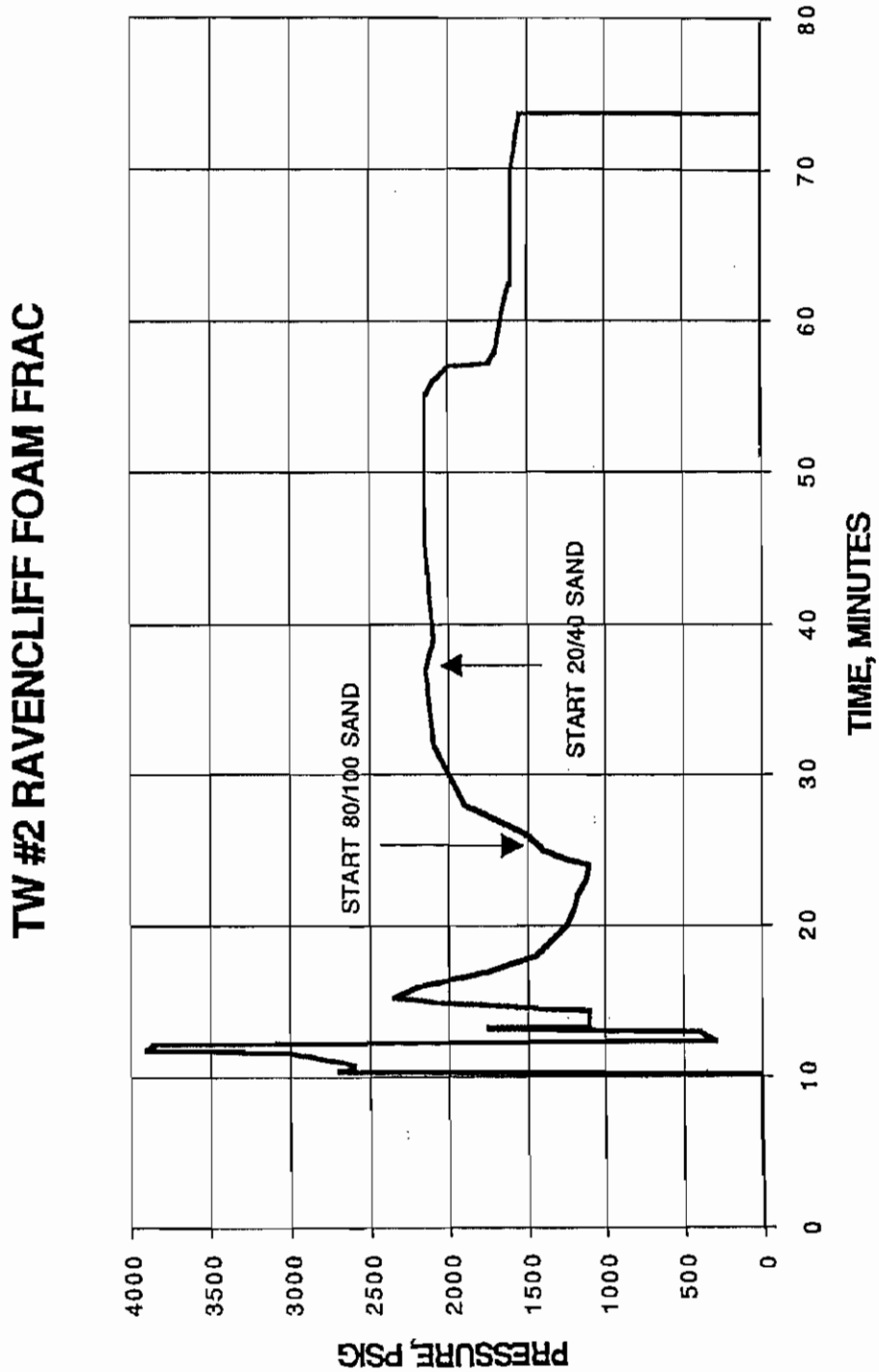



Figure 7.4.1 - Pressure History of the Ravencliff Frac Job

was located at 954 feet with the Pocahontas #4 and #3 located at 1,220 and 1,250 feet, respectively. A 142-foot pocket was drilled below Pocahontas #3 so that the water produced from the productive coalbeds could be collected, sampled and pumped out. The total drilled depth of the 11" hole was verified by the well logger to be 1,396 feet (KB).

Following the open-hole logging operations on the shallow section of TW-3 (details in section 8.2), 1,357.9 feet of 32#/ft, 8-5/8" casing was set and cemented to the surface. Six cementing baskets were run along the 8-5/8" casing; two baskets above the Beckley coal seam, two above the Pocahontas #3 coal seam, and two between the Beckley and the Pocahontas #4. A total of six centralizers were used when running the 8-5/8" casing in the hole. The cementing baskets main purpose was to act as a cushion above the coal seams to reduce the pressure exerted by the cement column above the coal seams.

Drilling the deep hole section of TW-3 was initiated on November 3, 1991, at 7:00 AM by drilling out the cement shoe with a 7-7/8" drill bit. Drilling of this section occurred without incident. The 1,797-foot section of hole, from 1,396 feet to 3,193 feet, was drilled in forty-six hours at an average penetration rate of 39 feet per hour.

Upon reaching the total depth of 3,193 feet, drilling was halted and the 7-7/8" hole was logged (See section 8.2). Following the logging operations, 3,158.9 feet of 10.5#/ft, 4-1/2" casing was run to the surface with ten centralizers placed at various points along the 4-1/2" casing. A left-right-threaded nipple and collar was placed at a depth of approximately 1,321.5 feet, immediately above joint #43, to allow retrieval of the 4-1/2" casing during the stimulation of the coal seams.

8.2 Logging Operations:

The TV Video camera Log and a suite of geophysical well logs, which included Gamma Ray, Caliper, Spectral Lithodensity, Sidewall Neutron, and Dual Induction were run in both sections of the hole; the shallow "coal seams" section and the deep "sandstones" section. In addition, the mud log was run simultaneously with the drilling operations. The data collected from the mud log were evaluated and correlated with the geophysical well log interpretations. Furthermore, the video camera logs indicated the zones of gas and water production which helped design the stimulation jobs for the different zones.

The video camera log showed water production at a depth of 1,286 feet in the shallow section. In addition, the video camera log revealed the intensity of the fractures in the deep section of the well, which assisted BDM engineers in designing the cement job on the 4-/2" casing.

8.3 Cementing Operations:

One-thousand, three-hundred, fifty-seven, and 9/10 feet (1,357.9') of 32#/foot, 8-5/8" casing was cemented in place all the way to the surface using 289 sacks of Class A cement with 2% $CaCl_2$. Circulation was achieved with 80 bbls of water prior to the start of the cement job. The total slurry yield was estimated to be 341 cubic feet at a yield rate of 1.18 cubic feet/sack.

After running 3,158 feet of 4-1/2" casing, the 7-7/8" hole was cemented from 3,115 feet to

1,592 feet using 340 sacks of 50/50 POZ cement with 2% gel and 10% salt. The cement top was approximately 200 feet above the Ravencliff formation. The cement job was designed in this manner in order to support the casing and to contain stimulation fluids in case the Ravencliff was stimulated.

## 8.4 Stimulation Operations:

After reviewing the hydrocarbon mud log, the geophysical well logs, and the video camera log, the potential productive zones were selected for stimulation. The stimulation treatments were designed after reviewing the different stimulation methods on the nearby wells and the improvements in productivity due to these stimulations. Service companies were approached and consulted for their expertise on the stimulation methods used in the area of interest for the different selected targets. BDM then designed and supervised the execution of three stimulation treatments on the Ravencliff sandstone, on a gas-bearing fracture above the Ravencliff and on the Pocahontas #3 and #4 coal seams.

### 8.4.1 Ravencliff Treatment

Starting with the stimulation of the Ravencliff, on January 28, 1992, a 4-1/2" drillable bridge plug was set at a depth of 1,830 feet. The Ravencliff was then perforated at a depth between 1,790 and 1,803 feet with 10 shots under 1.5 bbls of 15% HCl. The perforations were placed at the following depths:

| Depth | No. of Shots |
|---|---|
| 1790'-1795' | 1 shot/ft = 6 shots |
| 1801'-1803' | 1 shot/ft = 3 shots |
| 1804' | 1 shot/ft = 1 shot |
| | Total = 10 shots |

On January 30, 1992, at 7:00 AM, Nowsco was set up and ready to frac the Ravencliff formation. A total of 500 gallons of 15% HCl were pumped into the Ravencliff ahead of the frac job. The stimulation treatment was designed to pump 25,000 gallons of 80-quality nitrogen foam and 40,000 lbs of sand (35,000 lbs of 20/40 mesh sand and 5,000 lbs of 80/100 mesh). Prior to pumping the job, the surface equipment was pressure tested at 3900 psig. The Ravencliff breakdown pressure was recorded at 1750 psig. As shown in Figure 8.4.1, the maximum treating pressure was 2470 psig with an overall average treating pressure of 2326 psig. The 40,000 pounds of sand were pumped to a maximum concentration of 3.0 lb/gallon of foam using a total nitrogen volume of 359,760 scf and 119 bbls of "clean" water, equating to approximately 600 bbls of foam.

Immediately following the treatment of the Ravencliff, the instantaneous shut-in pressure (ISIP) was recorded at 2020 psig. The 5-, 10-, and 15-minute shut-In pressures (SIP) were recorded at 1740, 1720, and 1690 psig, respectively.

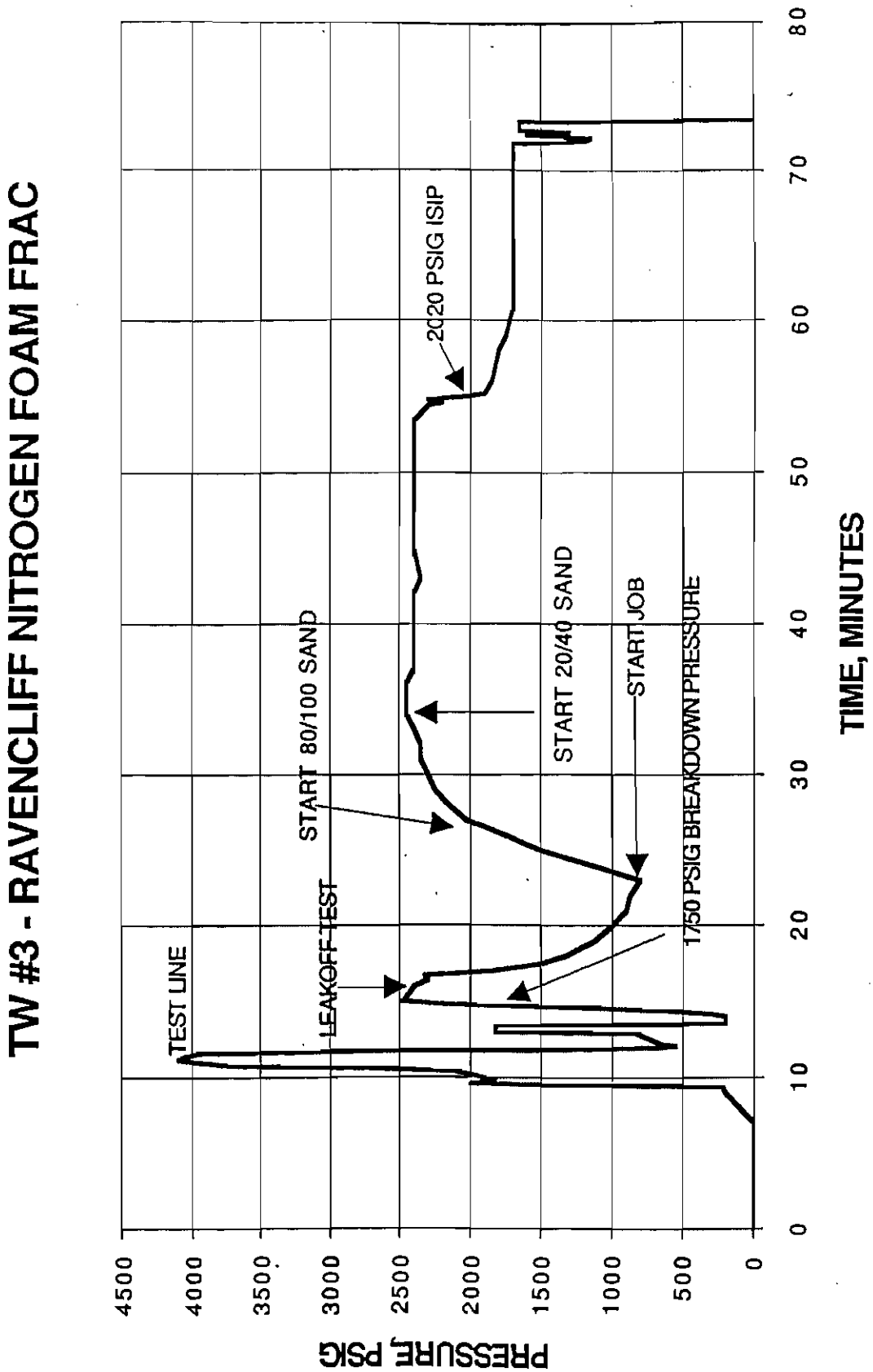



Figure 8.4.1 - Treating Pressures for the Ravencliff Sandstone in TW-3

### 8.4.2 Treatment of Gas Bearing Fracture Zone

The geophysical well logs and the mud log indicated natural gas production potential from a fracture zone at a depth between 1,594 and 1,600 feet. On February 7, 1992, a 4-1/2" drillable bridge plug was set at a depth of 1,630 feet, above the Ravencliff formation to isolate it from the gas bearing target for to be stimulated. Prior to setting the bridge plug, the pressure in the Ravencliff was recorded at 80 psig with a fluid column of 1,000 feet.

Fifty-five gallons of 15% HCl were spotted opposite of the gas bearing zone and the remainder of the hole was filled with water. A total of 10 shots initial holes were shot between 1,594 and 1,600 feet. The zone was then tested for gas production and found to be dry. Another attempt was made, placing a second set of nine perforations in the target zone. The results were identical to the first attempt. It was then decided to breakdown the formation by pumping water. Little or no water could be injected, even though the well was pressurized to 1990 psig. The gas bearing formation was again tested for natural gas production and showed no indication of any gas flow. At this point, it was decided that gas production could not be restored to the formation in question. The water was then swabbed to a depth of 1,630 feet so that the drillable plug could be drilled out.

### 8.4.3 Stimulation of Pocahontas Coal Seams

Following the attempt to treat the gas bearing fracture, Halliburton Logging Services Company moved on location on February 10, 1992, to set up and perforate the Pocahontas #3 and #4 coal seams.

An 8-5/8" retrievable bridge plug was set at a depth of 1,271.5 feet, below the Pocahontas #3 and #4 coal seams. Prior to setting the 8-5/8" bridge plug, the 4-1/2" casing was backed-off from a depth of 1,322 feet (L-R nipple was located at this point) to the surface and laid down on the ground. At this point, the Pocahontas #3 and #4 were accessed through the 8-5/8" casing, and a 2-3/8" tubing string was run in the hole where 250 gallons of 15% HCl acid was spotted at the perforation locations. The Pocahontas #3 and #4 coals were perforated at the following depths:

| | | | |
|---|---|---|---|
| 1244 | - | 1245 | 8 Shots |
| 1221.5 | - | 1222.5 | 4 Shots |
| 1213 | - | 1216 | 24 Shots |

A total of five perf-gun runs were made to place all the above perforations.

Following the perforation job, the retrievable packer was run on the 4-1/2" casing to a depth of 1,263 feet (KB). The perfs were washed using 67 bbls of water pumped down the 4-1/2" casing at a rate of 8 bbls per minute (BPM). The retrievable packer was then set at 1,176 feet in preparation for stimulation job.

On February 11, 1992, the water and the acid, which had been spotted on the previous day during the perforation and wash job, were swabbed from the coal through the 4-1/2" casing. A total of 750 gallons of 15% HCL with 50 perf-balls were then pumped down the 4-1/2" casing

to breakdown the formations in preparation for the frac job. An ISIP of 920 psig (surface) was recorded indicating a frac-gradient of 1.2 psi/ft. The retrievable packer was moved up and down the hole across the perfs, in order to free up any perf-balls remaining in the perfs and to insure that the spotted acid had contacted the perfs.

Following this activity, the water and acid were swabbed through the 4-1/2" casing to clean the Pocahontas seams for the frac job.

The Service company rigged up the frac equipment and proceeded to test the surface lines and equipment at a pressure of 4300 psig. The Pocahontas #3 and #4 coal seams were treated as one stage with 80-quality nitrogen foam at a rate of 15 BPM using 100 sacks of 80/100 mesh sand and 530 sacks of 20/40 mesh sand. The total volume of nitrogen pumped into the coal seams was 546,360 scf with 247 bbls of water, equivalent to approximately 40,000 gallons of foam. The treatment job was pumped to a maximum sand concentration of 3.0 lbs of sand per gallon of foam.

The initial treating pressure was recorded at 2294 psig with an average treating pressure of 1985 psig. At the end of the job, the ISIP value, the 5-, 10- and 15-minute SIP values were recorded at 1636, 1455, 1400, and 1322 psig respectively. Based on the 1400-psi (10 minute SIP) value, the fracture gradient following the treatment was approximately 1.26 psi per foot. Figure 8.4.2 presents a pressure versus time plot of the frac job.

Following the frac job, TW-3 was shut in for two hours prior to the flowback process. The well flowed back gradually at low rates through a series of small chokes before it was opened to flow through the 1/2" choke after pressure had clearly fallen below fracture closure pressure.

The next day, on February 12, 1992, the 4-1/2" casing was pulled, the retrievable packer was retrieved, and the 2-3/8" tubing was run into the hole to retrieve the 8 5/8" bridge plug set at 1271.5 feet. The 4-1/2" casing was then run in the hole and set immediately above the left-right nipple with a 7" swage at the bottom joint to insure the integrity of the left-right nipple if the 4-1/2" casing were to be accidentally run too deep. At this point the well was ready for swabbing the frac fluids from the Pocahontas #3 and #4 coal seams. Fluid recovery is discussed in Section 10.2.

## 9.0 PIPELINE CONSTRUCTION

Transportation and sale of produced gas was a key part of the final activities of phase II operations. A complete pipeline gathering system connecting all three of the test wells had to be designed and constructed. After the design was completed, request for bids to construct the pipeline had to be obtained and a subcontract let for the construction. After construction was completed the pipeline had to be pressure tested and then purged before it was ready to deliver gas to market. It was necessary to complete the pipeline before the production test could be conducted.

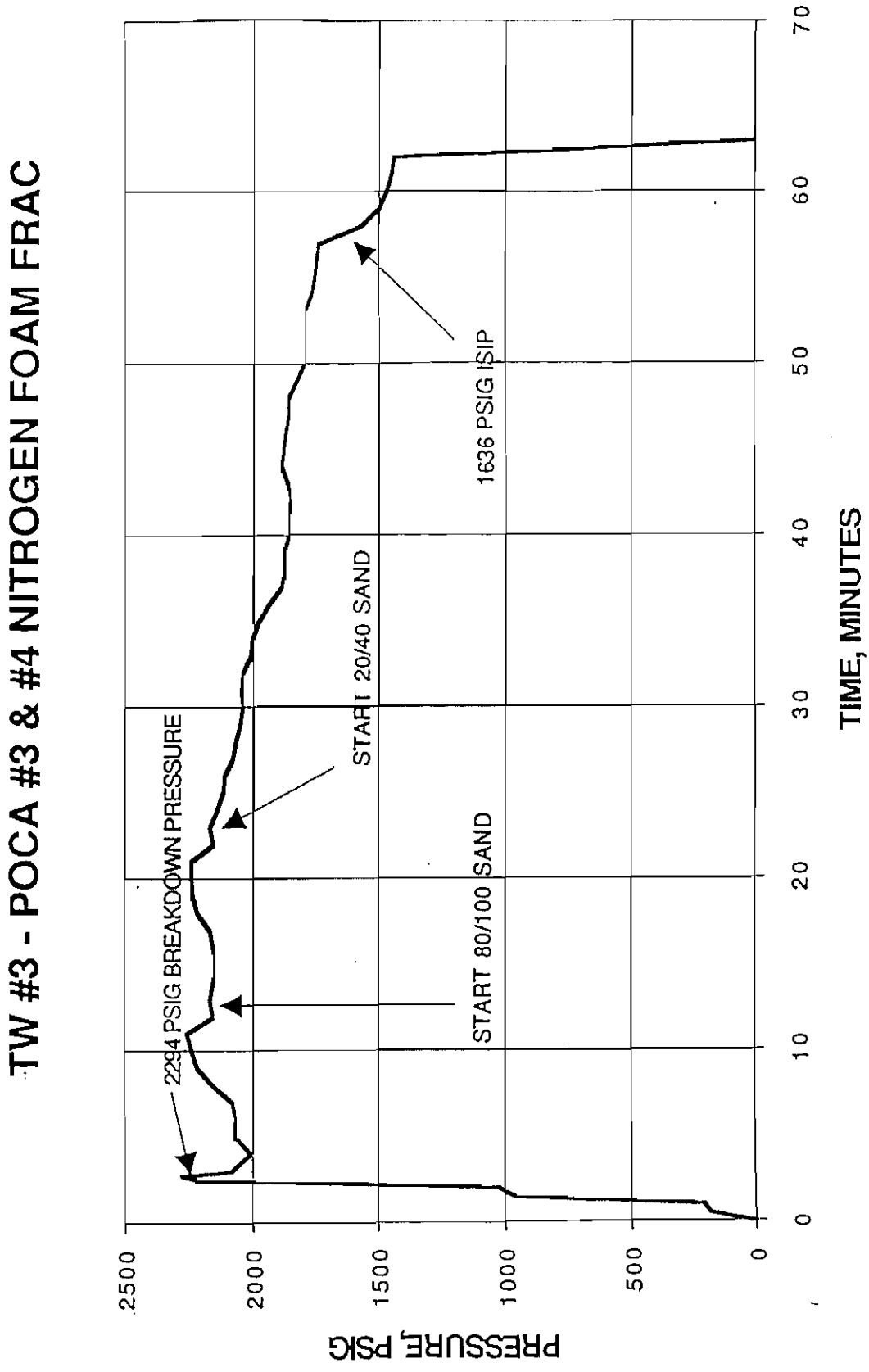



Figure 8.4.2 Pressure versus Time Chart for Treatment of the Coal Seams in TW-3

## 9.1 Pipeline Design

The initial aspect of the design was to review the reservoir pressure and projected production to determine volumes and pressure specifications for the gathering system. Our initial projections were that each would produce 75 to 100 mcfd, and that top pressure for the line would be 200 psig. A 2" diameter plastic line was selected as the most economical to construct.

The next task was to review the location of the leases and chart a course connecting the wells while remaining on the leased premises of Southern Land. An initial pipeline course was laid out considering the terrain and lease boundaries and this was sent to Southern Land for review and concurrence. Mr. Don Pauley, Vice-President of Southern Land reviewed the proposed location and recommended a shift in the pipeline on the Harper Creek side to make sure we were on Clear Fork Lease #8. The course was revised as indicated by Mr. Pauley and the course then chained, staked, and flagged by a surveyor.

The chained and flagged distances and a copy of the map were included in the specification package included in the request for proposal. (see Appendix 14.9).

The pipeline was designed to have close access to shut off valves and drips from main access roads and at intersections of the lines. Drips were located at low points along with shut-off valves. Shut-off valves and check valves were also placed at the point of intersection of the three pipelines so that any combination of 1 or 2 wells could produce while one or more were shut in for repair or workover. (Design point 2 in Appendix 14.9).

The wellhead-plumbing design for the dual completion is presented in Appendix 14.9. A pump to remove water from the coalbeds, a drip, and meter are the primary components of the coalbed methane production system which produces from the 8-5/8" casing. The deep Big Lime gas is produced from the 4-1/2" casing, via 2-3/8" tubing, and passes through a separator to knock out water before passing through a meter and check valve into the pipeline.

## 9.2 Pipeline Construction

Construction of the pipeline, which was approximately 14,000 feet long, was started in February, 1992 and completed in June, 1992. Three of the four road crossings were constructed without incident by pipe ramming. The fourth crossing at the Master Meter location encountered rock and had to be completed with a backhoe.

After the pipeline was completed, it was purged of air and pressure tested. A small leak was detected on the Sandlick Creek side where a bulldozer had created a leak by pressing a rock into the line. The leak was quickly repaired and pressure testing was completed in one day.

Where the pipeline construction could be viewed from the road, the disturbed soil was graded and grass was sown to reclaim the disturbed areas.

## 10.0 PRODUCTION TESTING

During cleanup operations on all three wells, it was observed that all were swabbing water at rates of approximately 2 to 5 bbls/hour which would produce 40+ bbls of saltwater a day, making the wells uneconomical. Therefore, a more-accurate water-influx rate test was designed and conducted on all three wells prior to making a decision about commercial viability. The results of this test showed water to be a potential problem in all three wells; therefore, a 30-day production test was designed to evaluate the water production over a longer period of time. The following sections present the results of these tests.

### 10.1 Water Influx Rate Testing

Plans were made to test each producing zone by employing a retrievable bridge plug and a casing packer on 2-3/8" tubing. The bridge plug was set below the perforations, and the tubing and packer were set above each set of perforations to test the water and gas production from that zone only.

A service rig was moved on location at TW-1 on February 24, 1992, and water-influx testing was initiated on the lowermost set of perforations in the lower part of the Big Lime formation. Successively shallower sets of perforations were tested by resetting the bridge plug and packer. The tests were very successful and it was determined that, of the 3 bbls of water per hour typically swabbed from the well, almost all of it was coming from the two lowermost set of perforations in the Big Lime. The Ravencliff in TW-1 was found not to be producing any water at all, but was making 253 mcfd of gas open-flow. A permanent bridge plug was placed above the lower perfs and water influx rate was slowed from 3 bbl/hr to 1.5 bbls/day, a 48-fold reduction.

TW-2 was tested for water by testing each of the perforations in the Big Lime and Ravencliff. A bridge plug was set at 2,805 feet and a packer was set at 2,789 feet.. The perforations in the Big Lime were tested by swabbing the water. Initially a total of 10 bbls were recovered and the Big Lime was producing at a rate of 1 bbl of water per hour with an open flow potential of 23 mcfd.

The bridge plug packer tubing assembly was moved upward to test the Ravencliff for water production. Results of this test indicated a water production of 5 bbls per hour and an open flow gas rate of 55 mcfd. These results indicated that the Ravencliff was not economical due to the high water production (120 bbls/day) and the cost of pumping, storing, and transporting the water. Based on these results a decision was made to isolate the Ravencliff by setting packers above the Big Lime and produce the Big Lime through the 2-3/8" tubing.

Water influx rate tests were then conducted on TW-3. A service rig was moved on location on March 2, 1992, to test the perforations in the Ravencliff, the lone producing horizon in TW-3. The swab results indicated that the zone was producing at a sustained rate of 8 bbls of water per hour. The high water production rate and the low gas production from the Ravencliff suggested the need to abandon the zone. A pump was set on TW-3 to produce the Poca #3 and #4 coal seams.

## 10.2 Thirty-Day Test

A 30-day production test, initiated on July 30, 1992, was conducteed on the three wells, but was delayed for TW-1 pending Columbia Transmission Company's testing of the gas composition from the coal zones. Columbia was concerned with the Oxygen content of the gas because the Beckley coal seam had been mined within 1,200 feet of the well location. On August 17, 1992, Columbia agreed to allow TW-1 to be produced, based on satisfactory test results.

TW-1 was tested for the last 13 days of the 30 day test period and the average daily production from all four zones (Big Lime, Ravencliff, Poca #3 and #4 coal zones, and the Beckley coal) was measured at 26.4 mcfd. As shown in Figure 10.2.1, most of the gas production was from the Big Lime and Ravencliff. Water from the coal zone was pumped at a rate of 5 bbls/day and was accompanied by a gas production of 1 mcfd. The well did not produce for four days during a period when the pipeline was shut in. Initial coalbed methane production at such a low rate was difficult to understand, since tests after stimulation produced an open flow rate of 47 mcfd. Again referring to Figure 10.2.1, water was pumped from the coal seams at a rate of 5 - 18 bbls/day, but without any increase in the production of methane. However, the nine-day duration of the test was apparently not long enough to establish methane production from TW-1 well. A longer test was needed on this well before any projections could be attempted.

TW-2 was completed in the Big Lime and Ravencliff and was mainly producing from the Big Lime at an average rate of 12 mcfd as shown in Figure 10.2.2.

The Ravencliff sand which produced too much water to be commercial still produced two to five mcf when opened up to produce every other day. This gas could be produced without producing any water.

Water would be produced from the Big Lime and would initially have to be disposed of about every 2 - 3 months upon accumulation of 75 to 80 bbls, or enough for a full truck load.

TW-3 was completed to the Ravencliff and the Poca #3 and #4 coal zones. During the 30-day test, the orifice meters indicated that most of the gas production was coming from the coal zones at a average rate of 8 mcfd when the coal zones were pumped at an average water production rate of 4 bbls per day. As seen on Figure 10.2.3, very little coalbed gas was produced when the well was not pumped. This was not unexpected and gas production was expected to gradually increase with time to a peak in 9 to 12 months, or longer, as the coals continued to dewater.

Figure 10.2.4 is a table of the results of the 30-day production test which includes both the gas and water production recorded from each well. The master meter production data were also recorded, and indicated an average daily production of 45 mcfd, from the three wells combined (Figure 10.2.5).

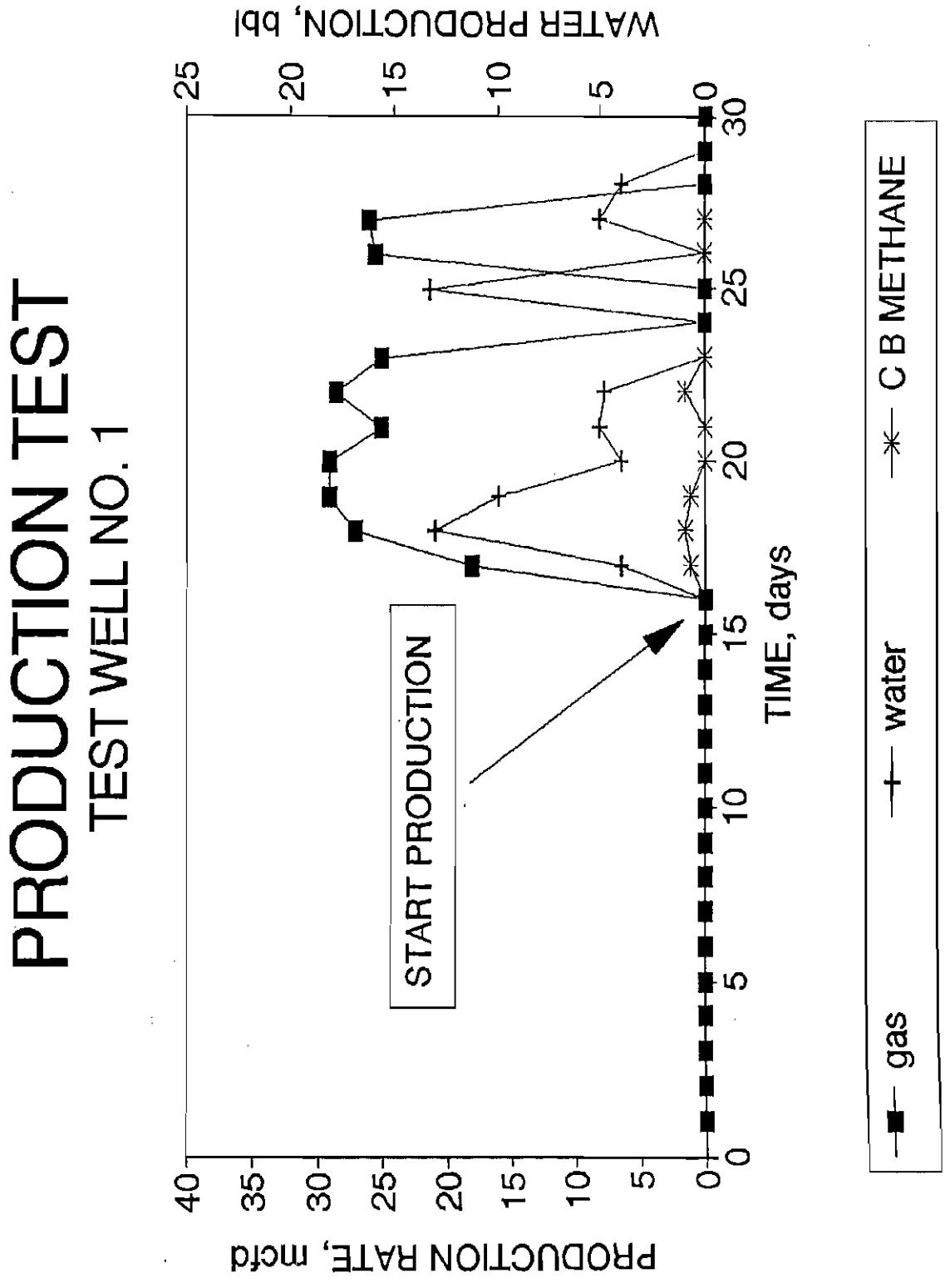



Figure 10.2.1 - Production Test Results for TW-1

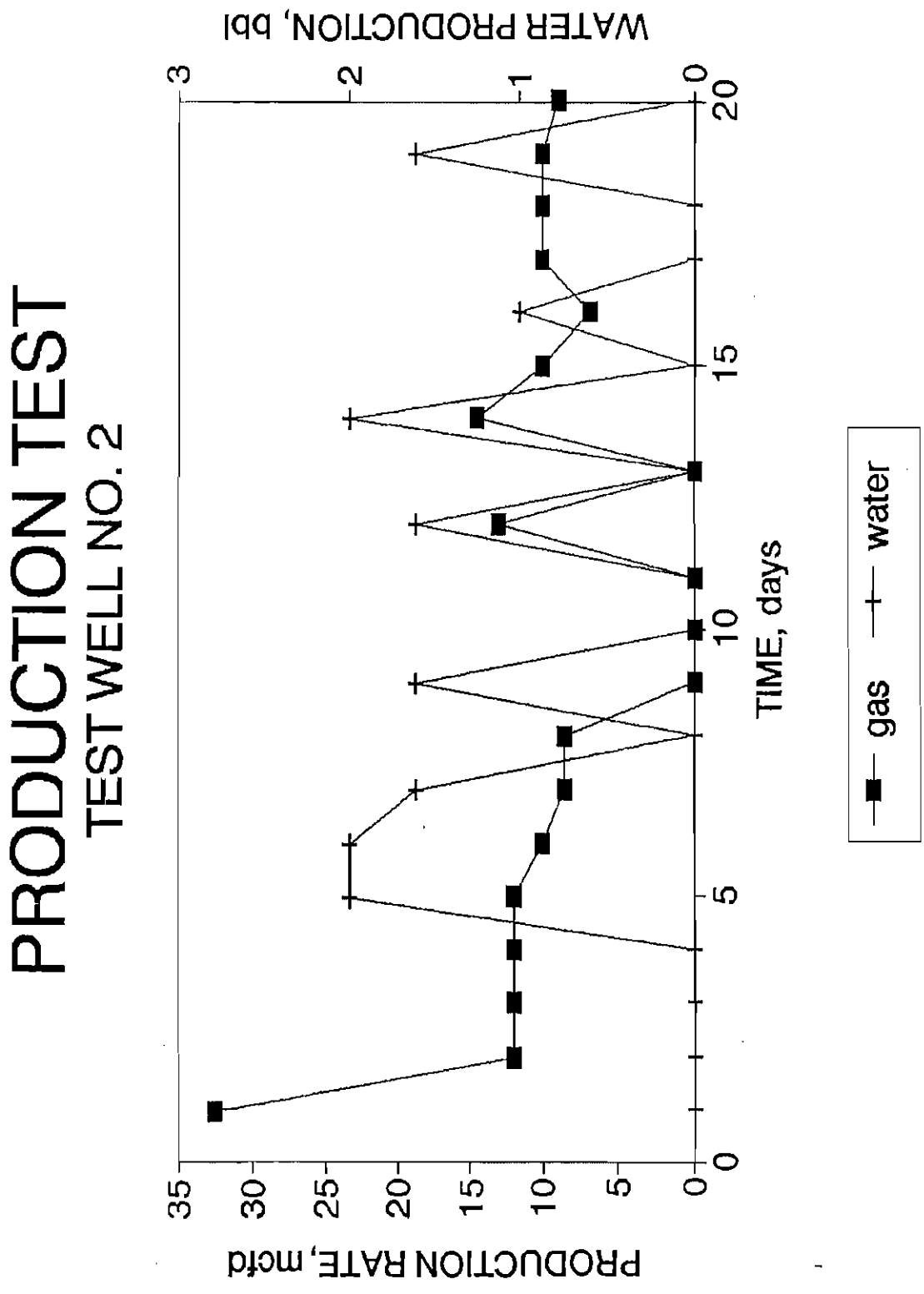



Figure 10.2.2 - Production Test Results for TW-2

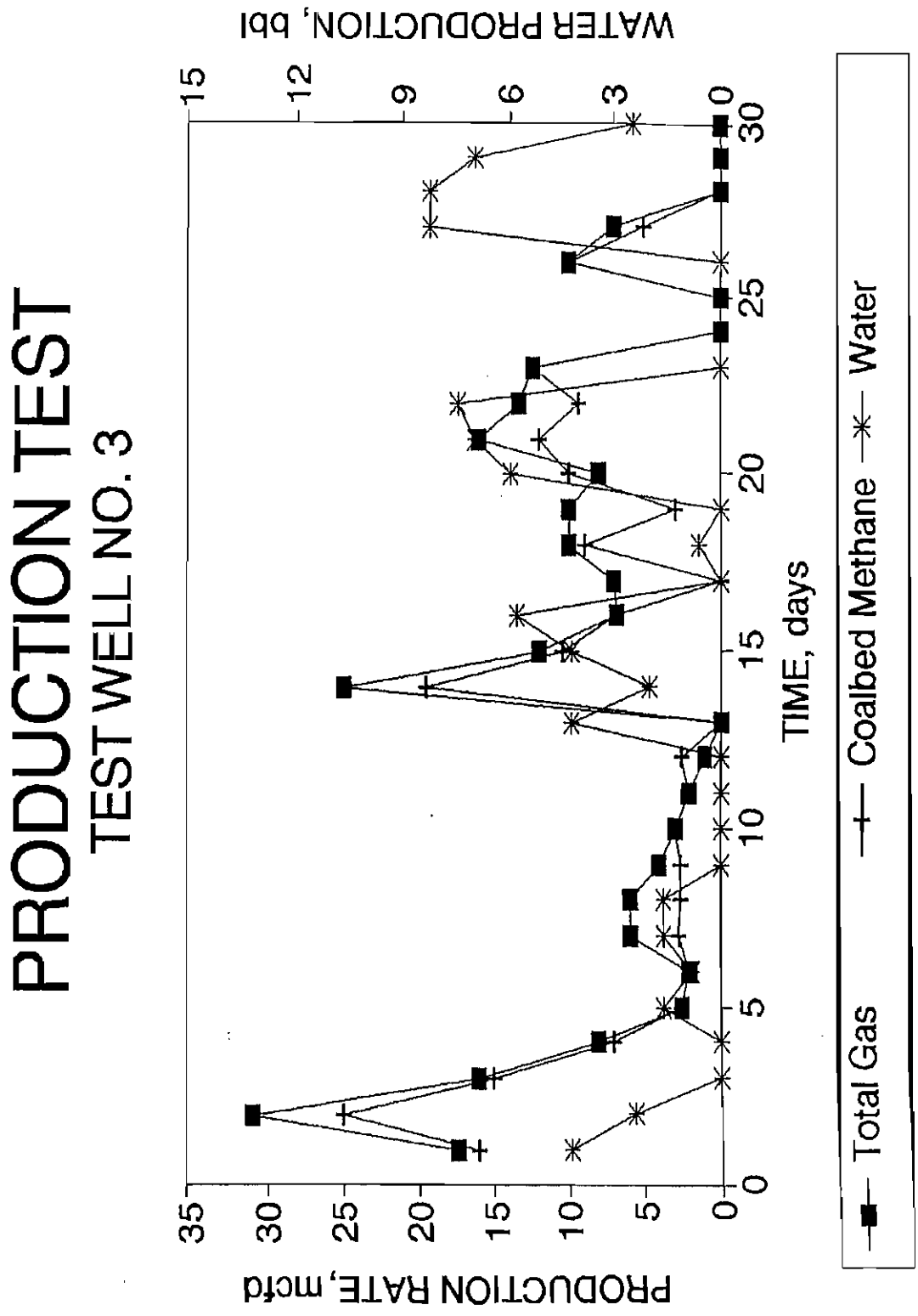



Figure 10.2.3 - Production Test Results for TW-3

Table 10.1 MULTISTRATA PROJECT

30-DAY PRODUCTION TEST DATA

| | TOTAL GAS PRODUCTION , MCFPD | | | | METHANE PRODUCTION, MCFD | | WATER PRODUCTION, BBLS | | |
|---|---|---|---|---|---|---|---|---|---|
| TIME, DAYS | TW#1 | TW#2 | TW#3 | MS METER | TW#1 | TW#3 | TW#1 | TW#2 | TW#3 |
| 1 | 0.0 | 32.5 | 17.5 | 50.0 | 0.0 | 16.0 | 0.0 | 0.0 | 4.2 |
| 2 | 0.0 | 11.5 | 25.0 | 45.0 | 0.0 | 25.0 | 0.0 | 0.0 | 2.4 |
| 3 | 0.0 | 12.0 | 16.0 | 28.0 | 0.0 | 15.0 | 0.0 | 0.0 | 0.0 |
| 4 | 0.0 | 12.0 | 8.0 | 20.0 | 0.0 | 7.0 | 0.0 | 0.0 | 0.0 |
| 5 | 0.0 | 8.7 | 2.6 | 15.0 | 0.0 | 2.6 | 0.0 | 2.0 | 1.6 |
| 6 | 0.0 | 10.0 | 2.0 | 12.0 | 0.0 | 2.0 | 0.0 | 2.0 | 0.8 |
| 7 | 0.0 | 8.2 | 2.8 | 14.5 | 0.0 | 2.7 | 0.0 | 1.6 | 1.6 |
| 8 | 0.0 | 0.0 | 2.7 | 12.0 | 0.0 | 2.6 | 0.0 | 0.0 | 1.6 |
| 9 | 0.0 | 14.4 | 2.6 | 16.7 | 0.0 | 2.6 | 0.0 | 1.6 | 0.0 |
| 10 | 0.0 | 0.0 | 3.0 | 13.5 | 0.0 | 3.0 | 0.0 | 0.0 | 0.0 |
| 11 | 0.0 | 0.0 | 2.0 | 13.0 | 0.0 | 2.0 | 0.0 | 0.0 | 0.0 |
| 12 | 0.0 | 10.0 | 2.6 | 14.8 | 0.0 | 2.5 | 0.0 | 1.6 | 0.0 |
| 13 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 3.9 |
| 14 | 0.0 | 19.0 | 22.0 | 38.0 | 0.0 | 19.5 | 0.0 | 2.0 | 4.2 |
| 15 | 0.0 | 10.0 | 11.0 | 20.0 | 0.0 | 10.5 | 0.0 | 0.0 | 5.8 |
| 16 | 0.0 | 6.8 | 8.0 | 16.5 | 0.0 | 6.8 | 0.0 | 1.0 | 0.0 |
| 17 | 0.0 | 0.0 | 0.0 | 33.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 18 | 27.0 | 10.0 | 10.0 | 48.0 | 0.0 | 9.0 | 0.0 | 0.0 | 0.0 |
| 19 | 29.0 | 10.0 | 3.0 | 42.5 | 0.0 | 3.0 | 13.3 | 1.6 | 0.6 |
| 20 | 29.0 | 7.0 | 10.0 | 47.0 | 0.0 | 10.0 | 10.0 | 0.0 | 1.7 |
| 21 | 24.0 | 10.0 | 13.0 | 44.0 | 1.0 | 12.0 | 4.2 | 1.7 | 5.8 |
| 22 | 27.0 | 9.4 | 10.0 | 47.0 | 1.5 | 9.4 | 5.0 | 0.0 | 7.5 |
| 23 | 24.0 | 9.5 | 13.0 | 52.5 | 1.0 | 12.5 | 4.0 | 0.0 | 0.0 |
| 24 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 25 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 26 | 25.5 | 15.3 | 10.0 | 50.0 | 0.0 | 10.0 | 13.3 | 1.6 | 0.0 |
| 27 | 26.0 | 10.0 | 7.0 | 45.0 | 0.0 | 5.0 | 0.0 | 0.0 | 8.3 |
| 28 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 5.0 | 0.0 | 8.3 |
| 29 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 4.0 | 0.0 | 7.0 |
| 30 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 2.5 |
| | | | | | | | | | |
| TOTAL | 211.5 | 236.3 | 203.8 | 738.0 | 3.5 | 190.7 | 58.8 | 16.7 | 67.8 |
| AVERAGE | 26.4 | 11.8 | 8.9 | 30.8 | 1.2 | 8.3 | 7.4 | 1.7 | 4.0 |

Figure 10.2.4 - Tabulation of Daily Production from 30-day Test for All Three Wells

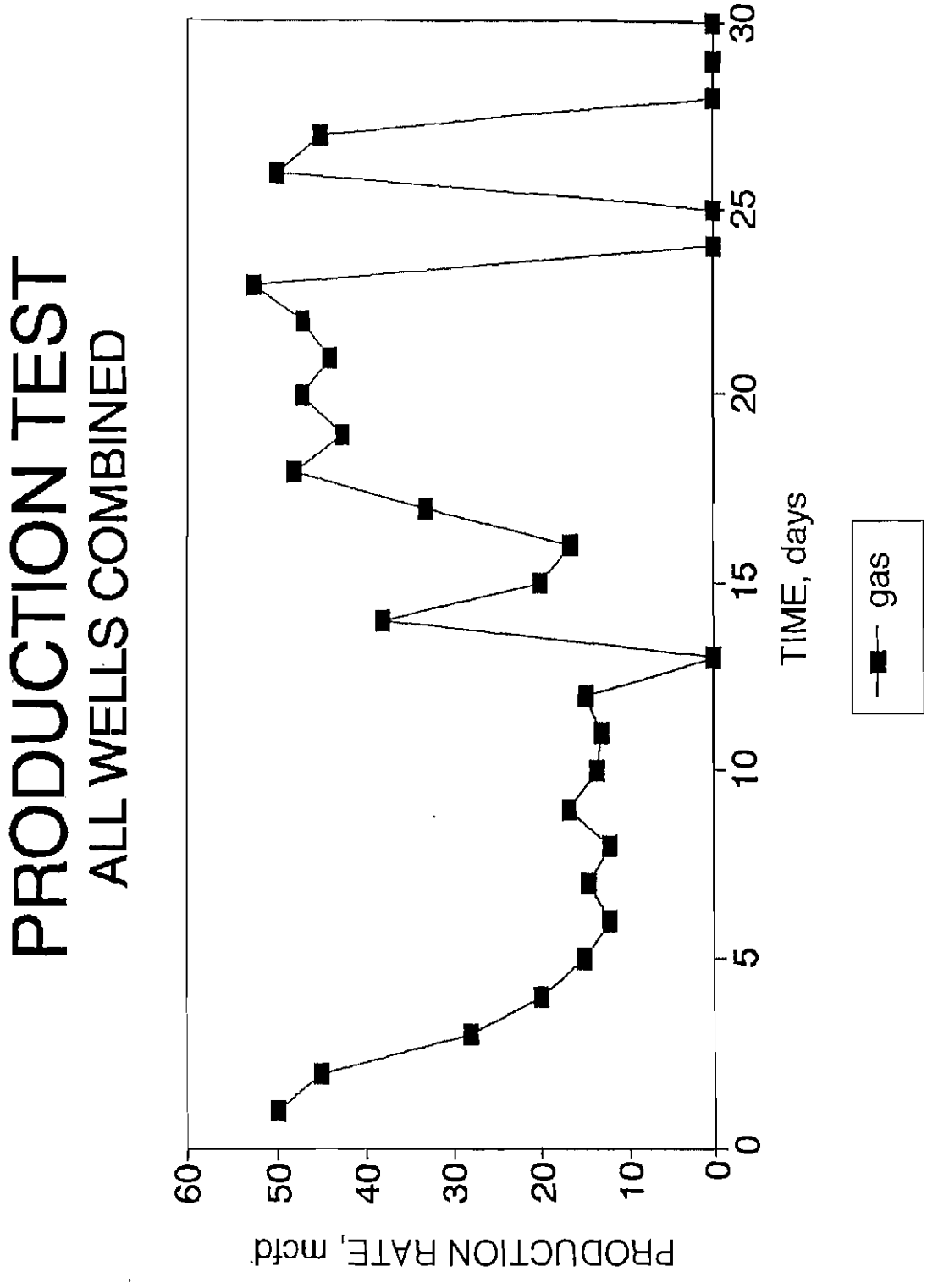



Figure 10.2.5 – Thirty-Day Production Test Results Showing Total Gas Production for All Three Wells Combined

The results of the 30-day test indicated the wells to be marginally commercial under the existing depressed gas market conditions. The results also suggested the potential for increasing gas production by periodically swabbing water from the 2-3/8" tubing in TW-1 and by installing a plunger lift system to remove water from the Big Lime in TW-2. Coalbed methane production was projected to increase with continued pumping of water from TW-1 and TW-3.

## 11.0 SUMMARY AND CONCLUSIONS

### 11.1 Analysis of Phase II Operations

The lineament, geochemistry, resistivity and seismic surveys gave enlightening, but not definitive, information for the siting of the test wells.

The seismic line demonstrated that a Basement fault did cut through the study area at the anticipated location, but, since only one line could be shot within the budget, it was impossible to confirm the fault orientation.

The lineament studies showed a number of prominent trends, but the major lineaments did not cut near any of the superior wells in the area. In this area, the best wells seemed to fall in the area between the major lineaments.

The resistivity survey generally verified the lineament studies. Anomalies were found at most of the points where the survey lines crossed the projected lineaments. Neither the lineament or resistivity surveys provided information that would aid in outlining the Basement block that was so important in controlling the coal or Big Lime depositional environments.

The geochemistry survey provided interesting data on oil in the survey area. Natural gas indicators cropped up almost everywhere, as they often do in regions of extensive well drilling and coal mining, with numerous pipelines and methane seeping from mine-disturbed areas. The oil indications on the hill crests showed that this portion of southern West Virginia was probably a good oil country, although the production potential has been destroyed by erosion.

In summary, for the company with limited exploration funds, a lineament study would be a low-cost operation. This should be followed by detailed geologic studies of the area. Finally, multiple seismic lines will confirm the presence and orientation of any Basement features that are influencing or controlling production.

The results of the drilling operations were compatible with anticipated results. Based on the optimization map, Location Number 1 (TW-1) was barely within an optimized target area with maximum permeability. Because the area had already been drilled a few years before and there were no undrilled leases available in the central part of the area, locating the well on the edge of the high permeability zone in an area where thick coals were anticipated was a logical choice. Reservoir pressure was about 50% of the original reservoir pressure which translates into a reduction of 75 to 85% in gas deliverability compared to original reservoir conditions. In other words, to compare TW-1 to a well drilled on the same site when the field was first

developed, one would have to multiply TW-1's production by a factor of 4 to 6. TW-1, therefore, would have delivered about 150 mcfd from the Big Lime and Ravencliff formations alone under original reservoir conditions. TW-1 was clearly an excellent location.

TW-2 and TW-3 were drilled in an area characterized by two of the three critical components. Those present were resource and reservoir, missing was the structure element. As originally mapped and projected, there was an indication of Big Lime structure being 50 feet above regional structure trend, which should have been structurally favorable. The faulting in the area had a greater impact than projected and the Big Lime was only about 10 feet above regional trend in TW-2 and 10 feet below regional trend in TW-3. TW-2 produced 11 mcfd from the Big Lime hampered by minor water production and TW-3 was not completed in the Big Lime at all because it appeared to be exceptionally wet. TW-3 well logs showed poor reservoir conditions and high water saturations in the porous zones of both the Big Lime and the Ravencliff sandstone. The upper fourteen feet of the Ravencliff sand was stimulated because of its higher gas saturation, but the zone produces 40+ bbls of water per day along with the non-commercial volumes of gas.

Only the coals appeared to have significant potential in TW-3, but would probably not be commercial by themselves. Once drilled, however, production from the coals is warranted on the basis of meeting and exceeding operating costs. Coalbed methane production also has a typically low rate of decline, often actually increasing during the early months of production.

The permeability of the Pocahontas #3 and #4 coals in TW-3 appears to range from about 0.1 to 3 md. These low permeabilities extend the period for dewatering of the coal seams longer than most commercially-produced coalbeds. The Pocahontas # 3 and #4 coals in TW-3 were projected to peak at a production rate of up to 30 or 40 mcfd after as much as three years of gradual dewatering. Initial stabilized production from the well was about 10 mcfd when the water was actively being pumped. Water production was projected to decline from its initial rate of approximately eight bbls/day.

The coalbeds in TW-1 should produce similar volumes to TW-3, but production is complicated by the comingling of the Beckley and Pocahontas production. The reservoir pressure in the Pocahontas #3 and #4 coals is substantially higher than the pressure in the Beckley coal seam (150+ compared to perhaps 60 psig for the Beckley seam). The Beckley coal appears to have better permeability (3 to 10 md) than the Pocahontas # 3 and #4 coals, and should produce its fluids, both water and gas, at rates comparable to those of the deeper Pocahontas seams. The net result of the comingling of the production from the coals may be that water from the Beckley seam floods the deeper Pocahontas seams, shutting off gas production, especially during times when the pump is not functioning. At other times, when the gathering line pressures rise (e. g., when the compressor is down), gas may produce from the deeper Pocahontas seams and be stored in the Beckley seam. This could be beneficial if water production from the Beckley is inhibited by the increased gas saturation. Another benefit could be higher (temporary) production rates as gas flows out of storage in the Beckley seam when gathering line pressures decline. These "benefits" of crossflow between seams is only valid, however, as long as the gas can be fully recovered from the Beckley seam, and there is no guarantee of this.

## 11.2 Conclusions

The validation of the exploration methodology was successful. TW-1 drilled in the optimized gas production area produces gas from five separate horizons, the Big Lime, Ravencliff sandstone, the Pocahontas #3 and #4 and the Beckley coal seams. TW-2 and TW-3 were located in less optimized areas with lower productive capacity and their lower overall productivity reflect the validity of the projections.

The exploration methodology could be easily used as a tool for development drilling in a newly-discovered area, or even in an older area such as found in the Eccles quadrangle.

## 11.3 Recommendations

A more complete study should be conducted on the same or a similar area with verification based on drilling at least five to ten wells to provide statistical confidence. Additional wells would also provide better insight and statistical confidence on multi-strata completion methods.

At the end of Phase II, it was recommended that the wells be placed on production, gas and water production monitored and recorded for each well in each individually-produced zone, and economic analyses be conducted only after stable production from all producing units could be achieved.

# 12.0 REFERENCES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4. Wrightstone, G.R., 1984. Ravencliff Becomes Exploration Target; Northeast Oil Reporter, V.4, No. 9, pp. 33-41.

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# 14.0 APPENDICES

ADDENDUM

AN OVERVIEW OF THE PRODUCTION TEST PERIOD 10/1/92 TO 6/31/98

Compiled by Ron Brunk, The College of West Virginia, 9/8/98

## 13.0 Addendum to the Multi-Strata Final Report

The purpose of this addendum is to document the field operations, gas production, and observations for the period following the original exploration research, development and validation phases of the project. Sections 13.1 through 13.4 address each of the test wells, TW-1 through TW4 respectively, and provide a chronological description of events, actions, and associated rationale impacting each of the wells. Also included in these sections are key data such as formation depths, pump setting depths, pump schedules, and general operating conditions to help the reader understand the rationale for various procedures, as well as the observed natural gas and methane production results. Section 13.5 discusses the observations on the addition of a compressor to further reduce gathering line pressure. Section 13.6 addresses the most significant factors affecting gas and methane production

## 13.1 TEST WELL 1

### 13.1.1 Background Information

Test Well No. 1 (TW-1, API Permit No. 47-081-912) was initially placed on production into the pipeline on October 1, 1992, and began producing from all target zones. The two deeper zones, the Big Lime limestone (2650 - 2898 feet) and the Ravencliff Sandstone (1660 - 1700 feet), are produced through a single meter and have produced an average of 40.6 mcf (thousand cubic feet) per day over the test period reviewed in this report. The two coals, the Beckley seam (801 - 806 feet) and the Pocahontas #3 (1083 - 1087 feet), are produced through a separate single meter and have produced an average of 5 mcf per day. Figures 13.1.1, 13.1.2, and 13.1.3 depict monthly gas production for TW-1.

By viewing the history of TW-1 (Figures 13.1.4 and 13.1.5), several important observations can be made. As demonstrated in other regions, coal gas production can be directly linked to coal water production. The months with the highest coal gas production were generally those when the pump system was operating at peak efficiency. Conversely, when the pump system was not operational (which was quite often), gas production dropped to its lowest levels.

Coal seam water production on this well has gone through several stages. Initially, a pump jack was used from October 1992 through July 1993. A progressive cavity pump was used (while the pump jack remained on site inactive) from August 1993 through September 1994. The damaged PC pump was removed and the pump jack placed back in operation in October 1994 and has continued to this date. Figure 13.1.4 shows that the highest level of methane gas production, accompanied by better-than-average water production, was achieved from October 1994 through June 1995 (after returning to use of the pump jack). Production tailed

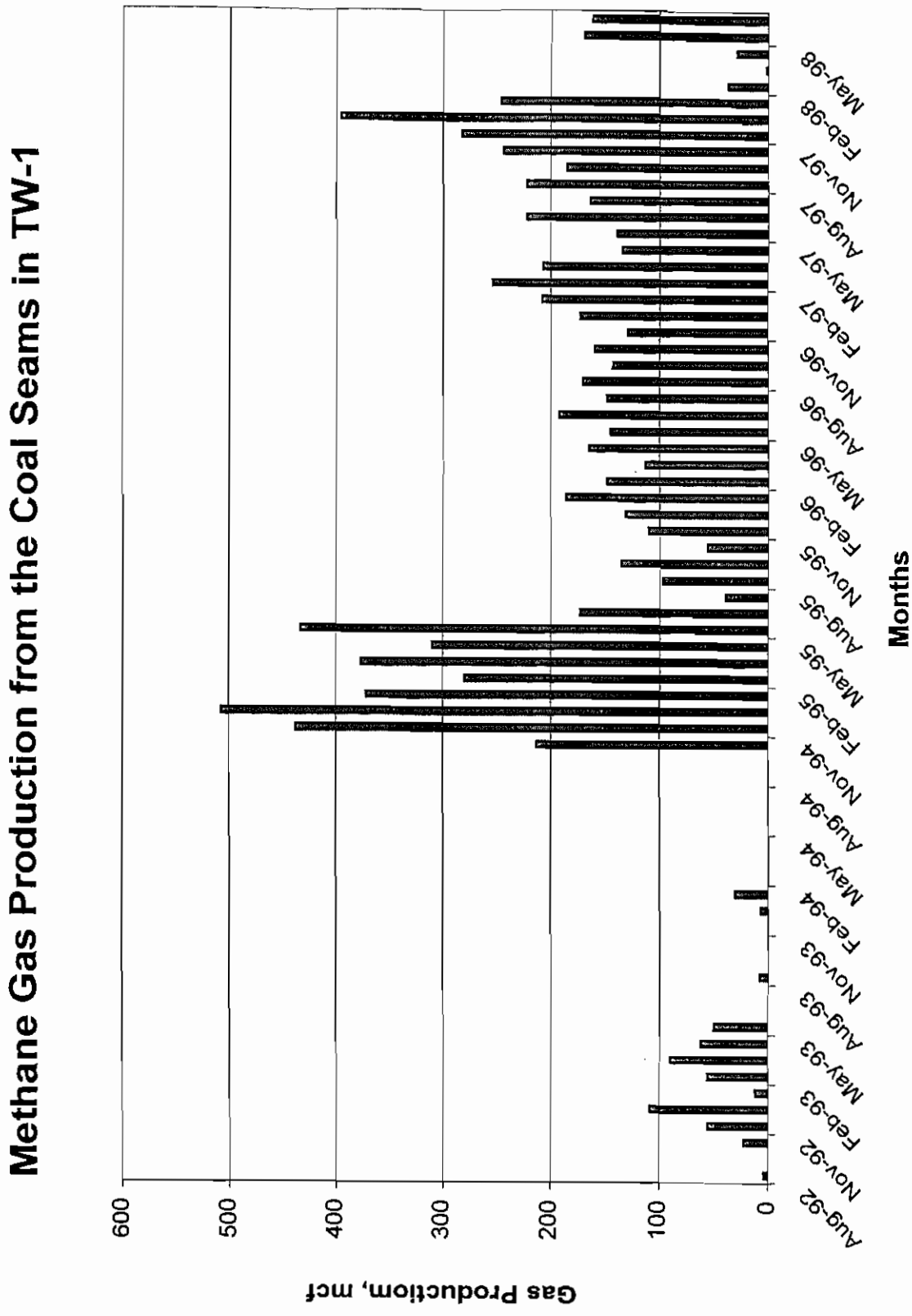



Figure 13.1.1 –Monthly Methane Gas Production for TW-1.

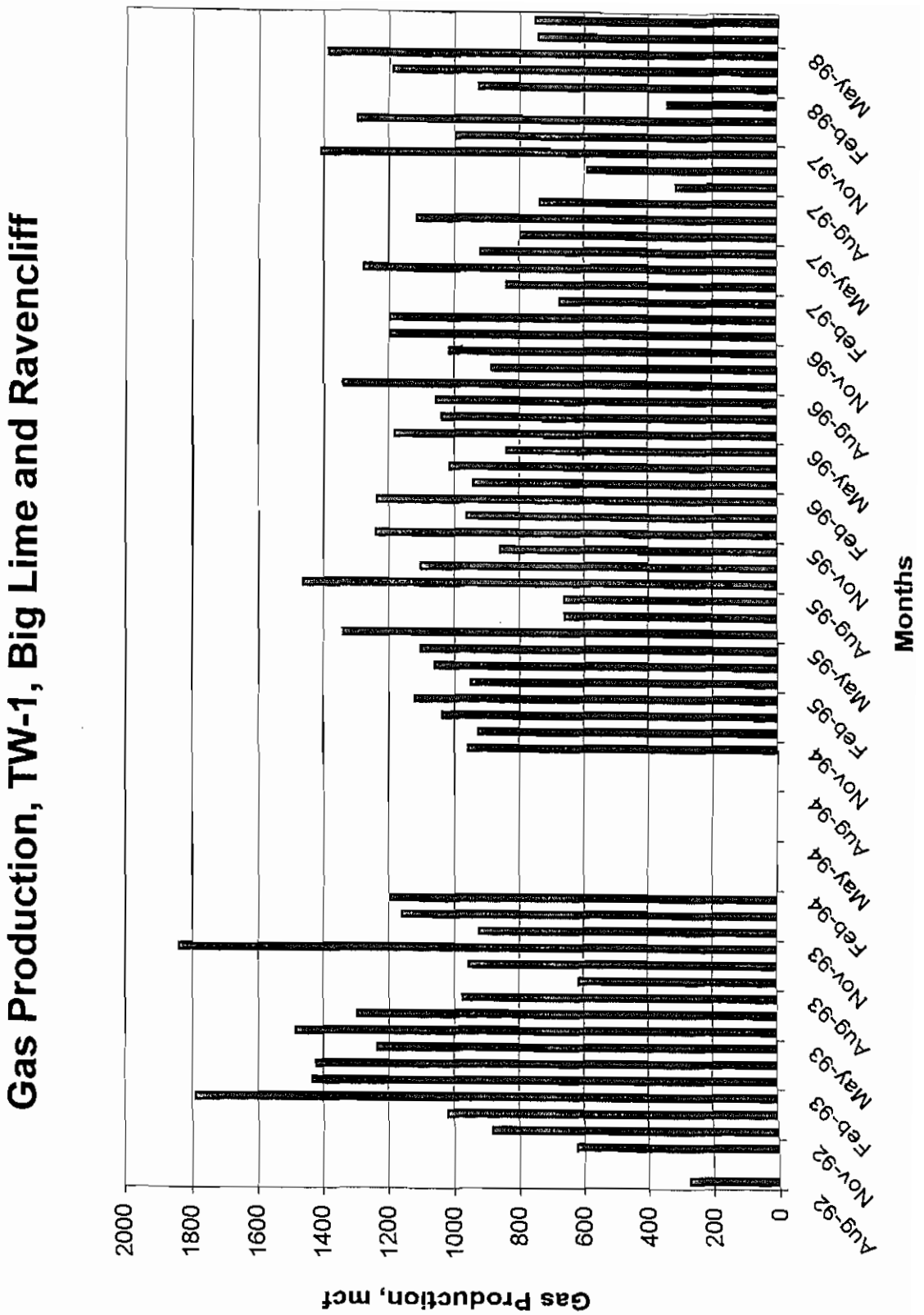



Figure 13.1.2 –Monthly Big Lime / Ravencliff Gas Production for TW-1.

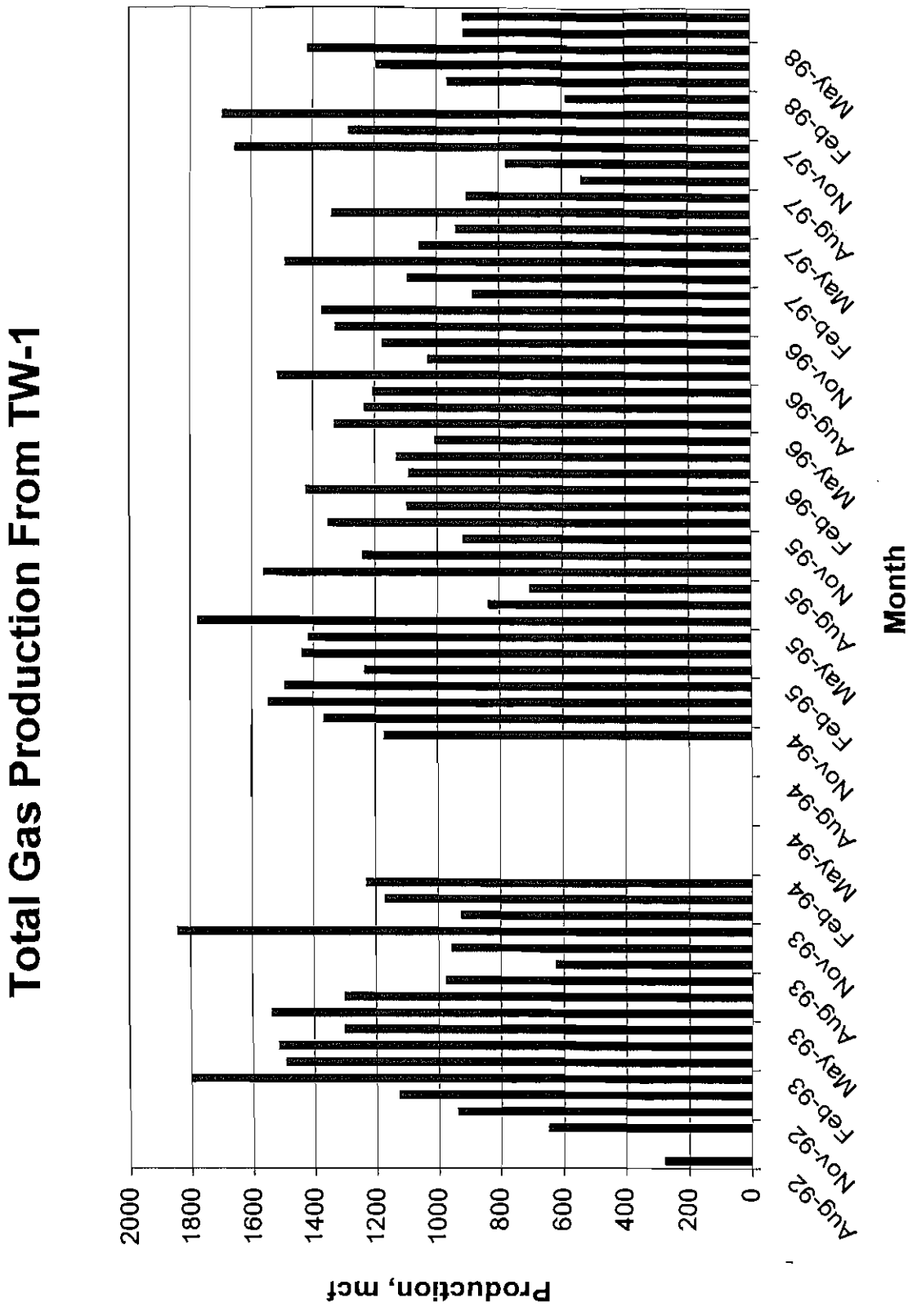
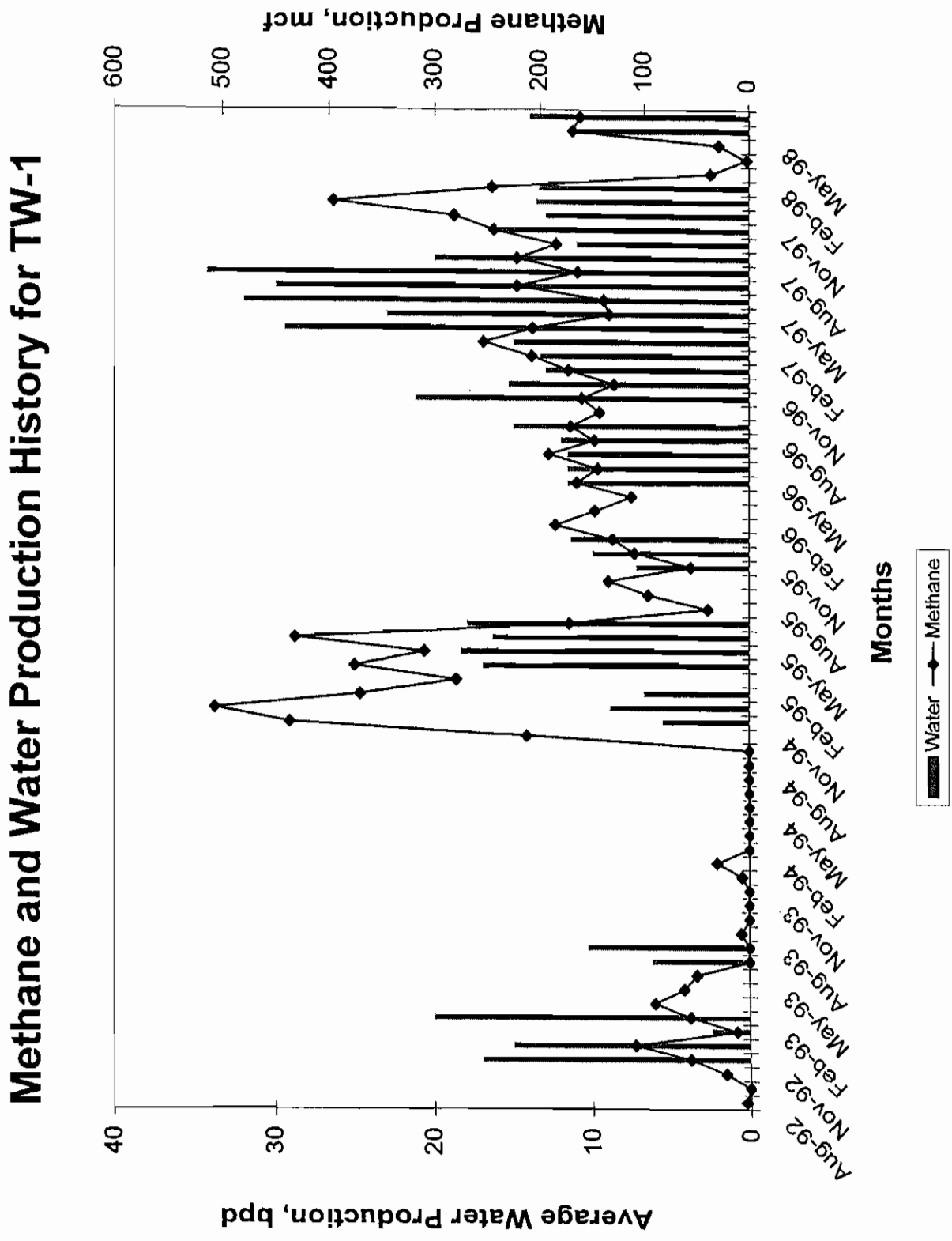



Figure 13.1.3 –Monthly Total Gas Production for TW-1.




Figures 13.1.4 – Methane and Water Production History for TW-1.

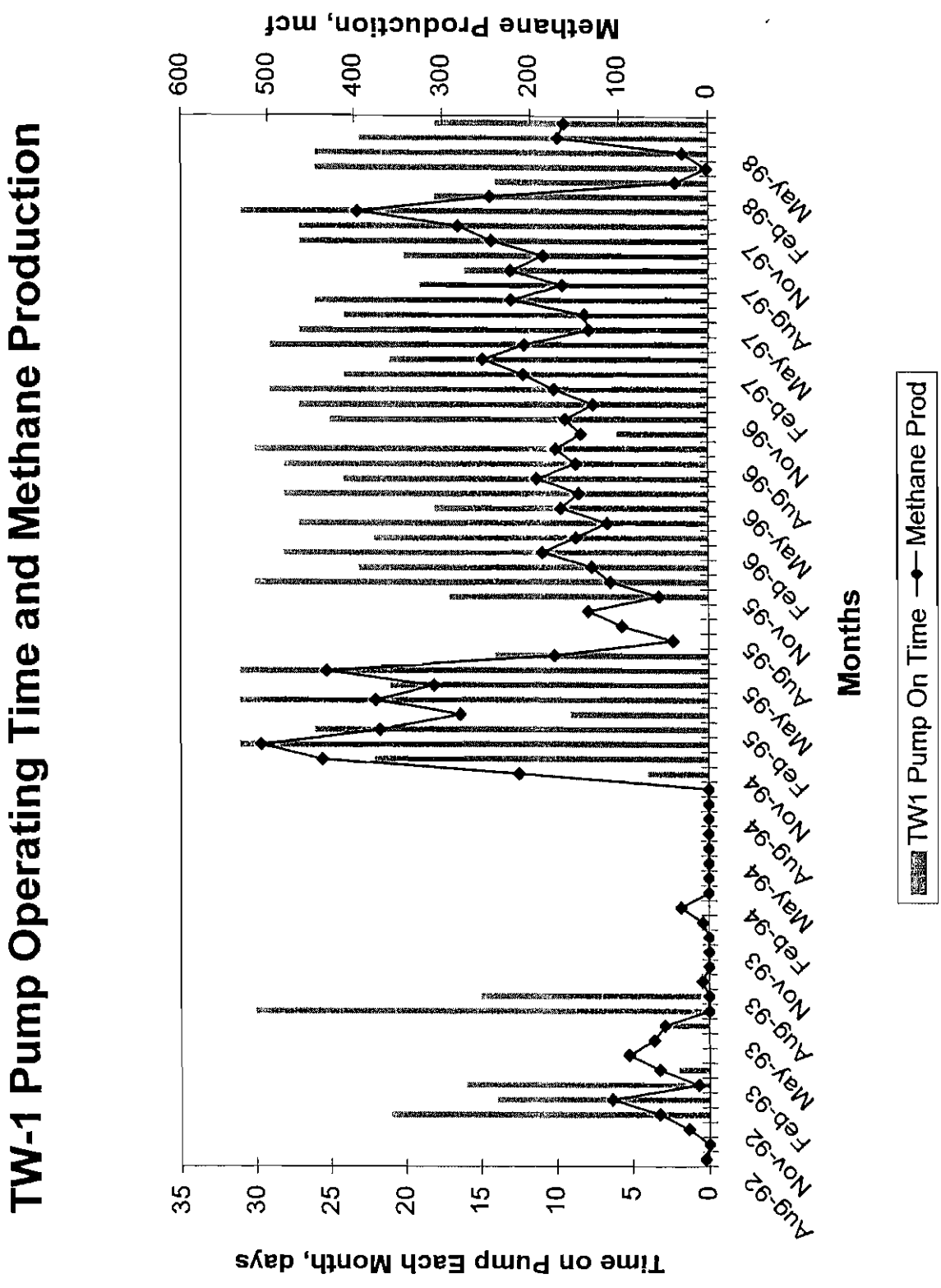



Figure 13.1.5 –Pump Operating Time and Methane Production History for TW-1.

off immediately after that, primarily due to hardware problems. Methane gas production has gradually increased since the low point in August of 1995, until winter weather and mechanical problems were encountered in January and February of 1998.

The progressive cavity pump simply seemed too sensitive to the conditions encountered in our setting. Since our wells, and probably our region, do not have high water production rates, the progressive cavity pump was very prone, which damaged the PC pump rotor and stator.

The fluid produced from the coal zones is fresh water and is typically collected in a 100 bbl tank for measurement. When the tank is full, the water is then dispersed to the ground. During times when transfer lines are frozen, the pumped water is dispersed directly to the ground without measurement. Over 18,000 measured barrels of water have been produced from the coals over the life of the well. When swabbing and direct land application periods are also factored in, the actual amount is probably closer to 20,000 barrels.

The brine produced from the deeper zones, primarily the Big Lime, is discarded when the well tender blows the well into the air. This is done approximately 2 to 4 times per month and brings a minimal amount of fluid. These zones continue to be strong producers by utilizing this method.

### 13.1.2 Coal Water Pumping System and Associated Problems

Dewatering activities on this well have encompassed an extremely wide range of hardware and methodologies. For the first five months of production, the coals were dewatered using a typical oil field pump and jack powered by a small Briggs & Stratton gasoline motor. Dewatering with this non-automated system was not effective and resulted in little gas production, averaging 2 mcf per day for the five-month period. The remote location coupled with the need for regular attendance of this system resulted in inconsistent dewatering and unacceptable gas production levels. The remote location made winter operations difficult, so system modifications were deferred until spring. With the arrival of more favorable weather conditions in the spring of 1993, a plan to automate the well site was implemented. This process involved three major tasks:

> placement of necessary electrical equipment,
> installation of power lines, and
> power drop/transformer placement by the local electric company.

The hardware for the task included the original Jensen Model #25 Pump Jack, a 5 horsepower, 1200 rpm single-phase electric motor, a 5 horsepower pump panel, a Semiens magnetic starter with 24-hour timer (with 15-minute increments), and pump-off controls. Downhole, the 2-3/8 inch tubing remained set just below the deeper coal zone, the Pocahontas #3. Power line installation included a 100-amp service mounted on a 6x6x20-foot treated pole at the base of the hill, 3500 feet of #2 triplex wire with hangers and insulators, and a 100-amp weather-proof switch mounted on a 6x6x20-foot pole on the well site. The power line was run up the access road from tree to tree.

As evidenced by the zero gas production levels from the coals shown in Figure 13.1.4, there were a number of problems with dewatering the coals on this well. Adverse weather conditions caused significant delays, both in installation of the electrical hardware and in operation of the pumping system. A variety of operational, hardware and design problems were also encountered, not the least of which was the local power company's heavy work load which led to several weeks lag time in obtaining a service drop. Another notable problem was the excessive voltage drop in the line from the base of the hill to the well site which was eventually remedied by installing an additional transformer in the line. The end result of these and other problems again can be clearly seen in Figure 13.1.5, which shows the monthly operating time for the pump on TW-1. The pumping system was operational only 21 of 151 days from January 1, 1993 through May 31, 1993, or about 14% of the time during this early phase of operations.

The coalbed dewatering process itself was found to be susceptible to a number of problems: hardware malfunctions, adverse weather conditions, vandalism, and imposed shut-in periods (imposed by Columbia Gas or other links in the transport/delivery system). Hardware problems were the primary cause of approximately 60% of the 554 pump system down days (see Figure 13.1.6). Adverse weather resulted in about 20% of downtime, imposed shut-in periods about 15%, and vandalism accounted for the remaining 5%.

Since there are so many components involved in the dewatering system, there are many possibilities for breakdown. From the power service drop at the base of the hill to the pump downhole, there are many links in what equates to a 5000-foot chain. Electrical problems have been a continuous problem throughout the life of the well. Often, wind, ice, or vandals damaged the power line running up the hill. Several motors were damaged or ruined as a result of starter breakdown, panel box problems, or voltage drop. Extreme cold often caused lines and valves to freeze, a problem exacerbated by the fresh water produced by the coal seams.
Coal fines and other solids repeatedly damaged parts of the pumping system downhole.

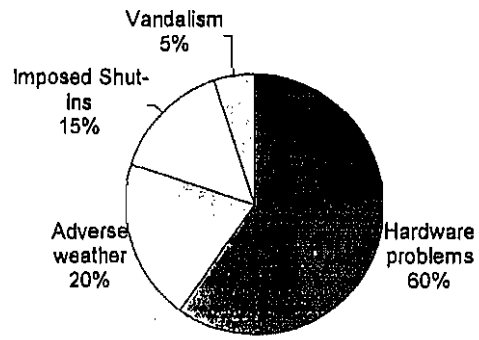


Figure 13.1.6 - Most Pump Downtime Caused by Hardware Problems

During the first three years of the project, these and other problems combined to keep the dewatering system on this well non-operational 554 out of 910 possible pumping days. This means that the pump system was operating as planned less than 40 percent of the time at best. With imposed shut in days factored into the mix, the actual operational pump time was closer to 30 percent.

### 13.1.3 Workover Activities: July - August 1993

Workover activities were conducted on TW-1 from July 19 through July 28, 1993; and August 20 through August 28, 1993. Daily field reports for this workover are included in Appendix 14.6. There were two major objectives of this workover related to TW-1: (1) to install a progressive cavity pump for dewatering the coals and (2) to do a small acid job to clean up the Big Lime formation.

The 2-3/8 inch and 1-1/2 inch strings were pulled, tallied and inspected. All zones were swabbed independently with poor water recovery on each run, and each zone was producing less than three barrels of water per day.

The standard bottom-hole pump was pulled and replaced with a progressive cavity (PC) pump. This was due largely to the many problems encountered and the poor response of the coals to the pump jack and bottom-hole pump. Since the PC pump on Test Well 3 seemed to be performing well during this same time period, it was deemed suitable to install an identical PC pump on TW-1. A drip tube was added for better water/gas separation.
Atmospheric flow tests during this workover period showed 30 mcf per day from the coals, an average 60 mcf per day from the Ravencliff Sandstone, and about 40 mcf per day from the Big Lime formation.

A small acid job utilizing 800 gallons of 15% HCL was performed on the Big Lime formation to clean out the perforations and fractures created by the original frac job. The zone went on vacuum for a few days and then slowly began to recover. Production faltered initially but returned to near-previous levels within a few weeks. The net result of the acid job appeared to be the creation of a near-wellbore water-block, which inhibited production until the block was cleared. Reference Appendix 14.6 for additional details.

### 13.1.4 Workover Activities: October 1994

Numerous workover activities were conducted from September 26 through October 19, 1994. This workover followed a long shut-in period from January 27, 1994, through September 30, 1994. This extended shut-in period came as a result of a legal dispute with Ramco Gas Company, into whose system these Project wells delivered their production. The primary thrust of the workover was the installation of a compressor on the entire well system. The activities specific to TW-1 will be described in this section.

A workover rig was moved on site October 5, 1994. The annulus was opened on the coal zone (8-5/8 x 4-1/2 inch) and the coals blown down. The 5/8" sucker rods and the pump rotor were pulled first. Then the 1-1/2 inch tubing and pump stator were pulled and all downhole parts were inspected. The fluid level on the coal zone was at 600 feet from the surface. This was based on evident wetness on the 21st joint on the 1-1/2" tubing.

Looseness of the rotor inside the stator on the progressive cavity pump indicated strong wear. A large accumulation of solids/coal fines/sludge was found in the pump sections and in

surface flowlines. Based on these findings, the Project Team discussed various options for continued dewatering of the coals.

A decision was made to remove the damaged PC pump and return to using the pump jack. There were several reasons for this decision. First, the progressive cavity pump had not improved production or performed well in the field. Second, hardware-related problems were persistent with the PC pump. Finally, the cost to repair the PC pump would be about the same as costs to reinstall and initiate pump jack operation.

The following day the 1-inch tubing from the Ravencliff and Big Lime zones was pulled. The 4-inch tools were used to measure in to 2870 feet and to plug back from total depth inside the 4-1/2 inch casing. The 4-inch swab tools and lubricator were prepared and the open flow was gauged with a manometer before swabbing, indicating 32/10 inches of water through a 2-inch opening or 239 mcfd from the combined Ravencliff/Big Lime zones.

The 4-1/2 inch swab was run and recovered 100 feet (65 gallon or 1.5 bbl) of fluid. After a half-hour, swab was run again recovering 40 feet (25 gallon or 0.5 bbl) of fluid. After waiting another half-hour, the open flow gauged 280 mcf per day. The 1-inch tubing (2783.25 feet, 56 joints) was then run back in hole open-ended. One joint of the tubing was found plugged with pipe scale.

The following day, October 7, 1994, the shut-in 1-inch tubing pressure was 90 psi. The 4-1/2" casing shut-in pressure was also at 90 psi. The tubing was opened and blown for 10 minutes. The shut-in tubing and casing pressure stabilized at 90 psig. The coals were then swabbed through the 1-1/2" tubing for four hours. The coals were then vented to atmosphere for 30 minutes. An open flow rate was gauged at 90/10 (inches of water) through a 1-inch opening, or 100 mcf per day. Swabbing was then resumed and total water recovered from the coals for the day was 670 gallons or 16 barrels. There was very little water on the last pull of the swab.

Final TW-1 workover activities were conducted the morning of October 10, 1994. The 1-1/2 inch x 1-1/4 inch x 8-foot insert pump was inserted on 5/8-inch rods. The pump was seated in the seating nipple at 1219.7 feet. The pumping T-fitting and stuffing box were prepared and the pump jack was readied for operation. After two hours, open flow on the coals was 75 mcf per day. Initial shut-in pressures were 85 psi on the Big Lime and Ravencliff, and 40 psi on the coals. All final surface activities were completed and the well was turned back in line.

Two weeks after the workover activities described in this section and with the installation of compression on the system, TW-1 was producing at quite acceptable levels. The deep zones were making 46 mcfd, with 70 psi back pressure. The coals were making 7 mcfd, fully open with no back pressure ( 6 psi line pressure).

Approximately three weeks after this workover, TW-1 was still producing well compared to pre-workover records. The deep zones were making 42 mcfd, with 55 psi of back pressure. The coals were making 18.5 mcfd, fully opened, against 10 psi line pressure.

### 13.1.6 Gas Production Summary

Gas production from the deep zones, the conventional gas producing formations, has ranged from a monthly low of 273 mcf to a high of 1840 mcf. The low occurred in August 1992, the start-up month for the project's production phase. The high came in October 1993. The average monthly production from the deep zones was 1081 mcf.

The low in monthly gas production from the coals was zero, which occurred, in 5 separate months when the pump system was not operational. The high was 507 mcf in December 1994. Production from the coals over the life of the well has averaged 132 mcf per month, including the shut-in months.

Combining the zones yields a total monthly average of 1031 mcf per month for TW-1. For the period covered by this report, August 1992 through June 1998, TW-1 has produced 73,209,000 cubic feet of gas. Almost 64 million has come from the deep zones, and more than 9 million from the coals.

## 13.2 TEST WELL 2

### 13.2.1 Summary

Test Well No. 2 (TW-2, API Permit No. 47-081-924) was officially turned in line October 1, 1992, and began producing from the Big Lime limestone (2772 - 3044 feet) and the Ravencliff Sandstone (1829 - 1838 feet). The two are metered together and have produced an average of just over 8 mcf per day over its life to the date of this report. Figure 13.2.1 depicts the monthly gas production for TW-2.

This well has the potential to produce from the deep zones in quantities similar to TW-1; however, water production is much greater and therefore drowns out much of the gas production. The cost of fully producing, hauling and disposing of the brine would not be economical as it was projected at 80 barrels per day. Currently only a small amount of brine is produced daily into the storage tank and brine hauling and disposal is performed only twice per year.

The coals were intended target zones on this well but were not completed due to a cementing problem during drilling activities. As a result, this is a typical conventional gas well whose production history has been quite similar to many others in southern West Virginia. The possibility of doing remedial work to allow for coal zone completion in this well was discussed. It was determined however, that the cost would run nearly $100,000 -- equivalent to drilling an offset coalbed well on the same site. Action on the offset well was not undertaken until 1995 and will be discussed later in this report. The TW-2 well site, unlike TW-1 and TW-3, is not automated.

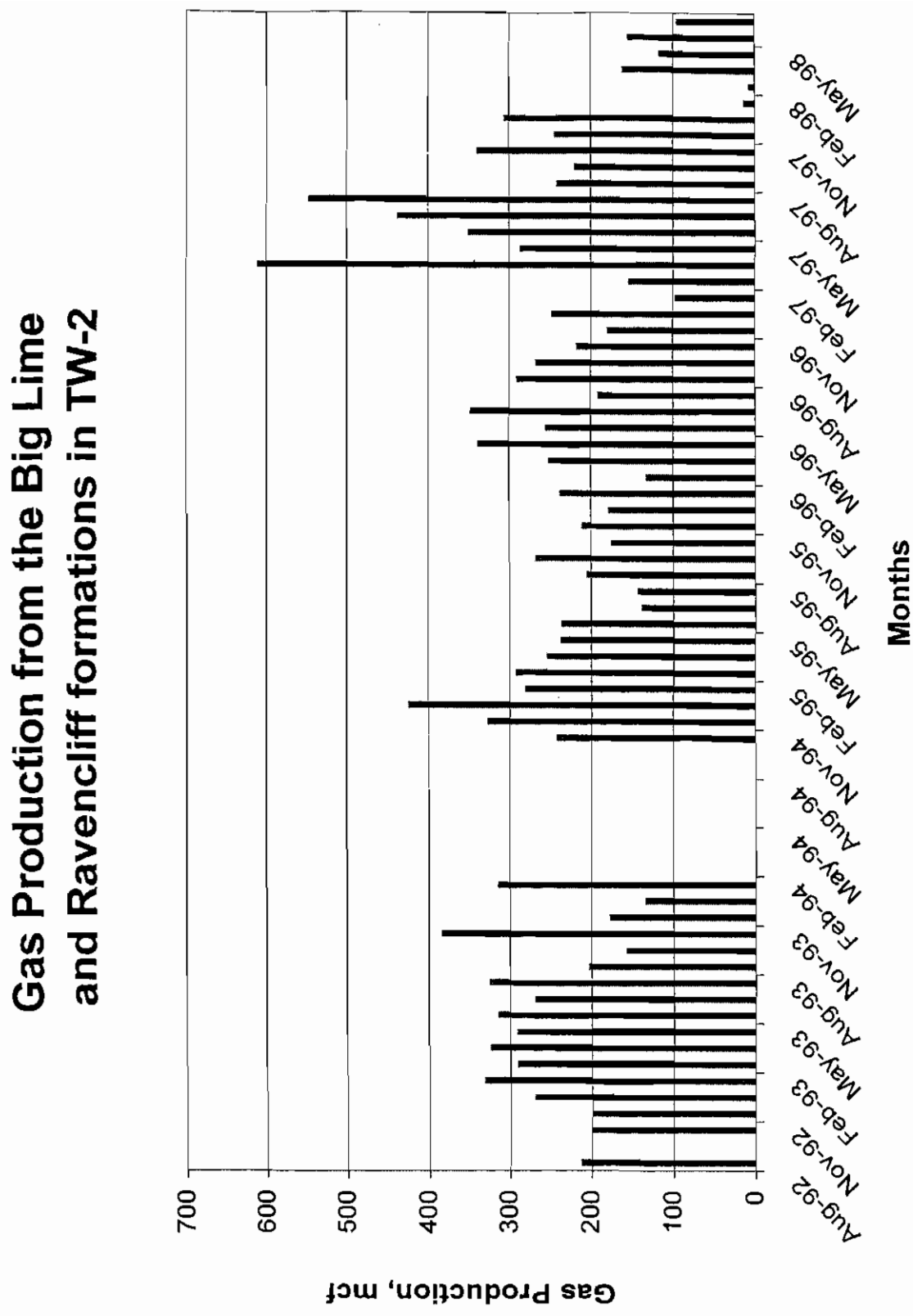



Figure 13.2.1 - Monthly gas production for TW-2.

### 13.2.2 Gas Production Summary

Gas production from TW-2 has been small but extremely steady. Records show that TW-2 has produced 15,400,000 cubic feet of gas from August 1992 through June 1998. Average daily production has been 8.2 mcf per day.

## 13.3 TEST WELL 3

### 13.3.1 Summary

Test Well No. 3 ( TW-3, API Permit No. 47-081-925) was officially turned in line October 1, 1992, and began producing from the Ravencliff Sandstone (1790 - 1804 feet) and the Pocahontas #3 coal seam strings (1213 - 1245 feet). The two were metered separately. The Ravencliff had poor initial shows during drilling and completion activities, and has had a poor production history. Several workover activities were conducted on this zone and will be discussed later in this section. The coals have performed very well, producing an average of just slightly less than 10 mcf per day over the test period reviewed in this report. Figures 13.3.1, 13.3.2, and 13.3.3 depict monthly gas production for TW-3.

There has been some academic dispute about the coal seams encountered in this well. There were two strands of coal found between 1213 and 1245 feet. Some felt that these were the Poca #3 and the Poca #4 seams. Others declared that it was the Poca #3 with a small rider split off the main seam. The issue has not been resolved but suffice to say, these coals that have been the prime producers in this well.

### 13.3.2 Coal Water Pumping System

As with TW-1, dewatering activities on this well have encompassed a wide range of hardware and methodologies. For the first five months of production (October 1992 - February 1993), the coals were dewatered using a PC pump powered by a small gasoline motor. Dewatering with this hardware was much more effective with this well than with TW-1. Of course, as evidenced by comparing the gas production histories of TW-1 and TW-3, this well has consistently outperformed TW-1 regarding coal gas production.

In the spring of 1993, a plan to automate the well site was implemented concurrent with the automation of TW-1. The two automation plans were actually nearly identical. This process involved three major tasks: placement of necessary electrical equipment, installation of power lines, and power drop/transformer placement by the local electric company.

The hardware for the task included a progressive cavity pump (model 35, stage 9, premium elastomer), a 3-horsepower, 1800-rpm single-phase electric motor, a 3-horsepower pump panel, a Semiens magnetic starter with 24-hour timer (with 15-minute increments), and pump-off controls. Power line installation included a 100-amp service mounted on a 6x6x20-foot treated pole at the base of the hill, 2900 feet of #2 triplex with hangers and insulators, and a

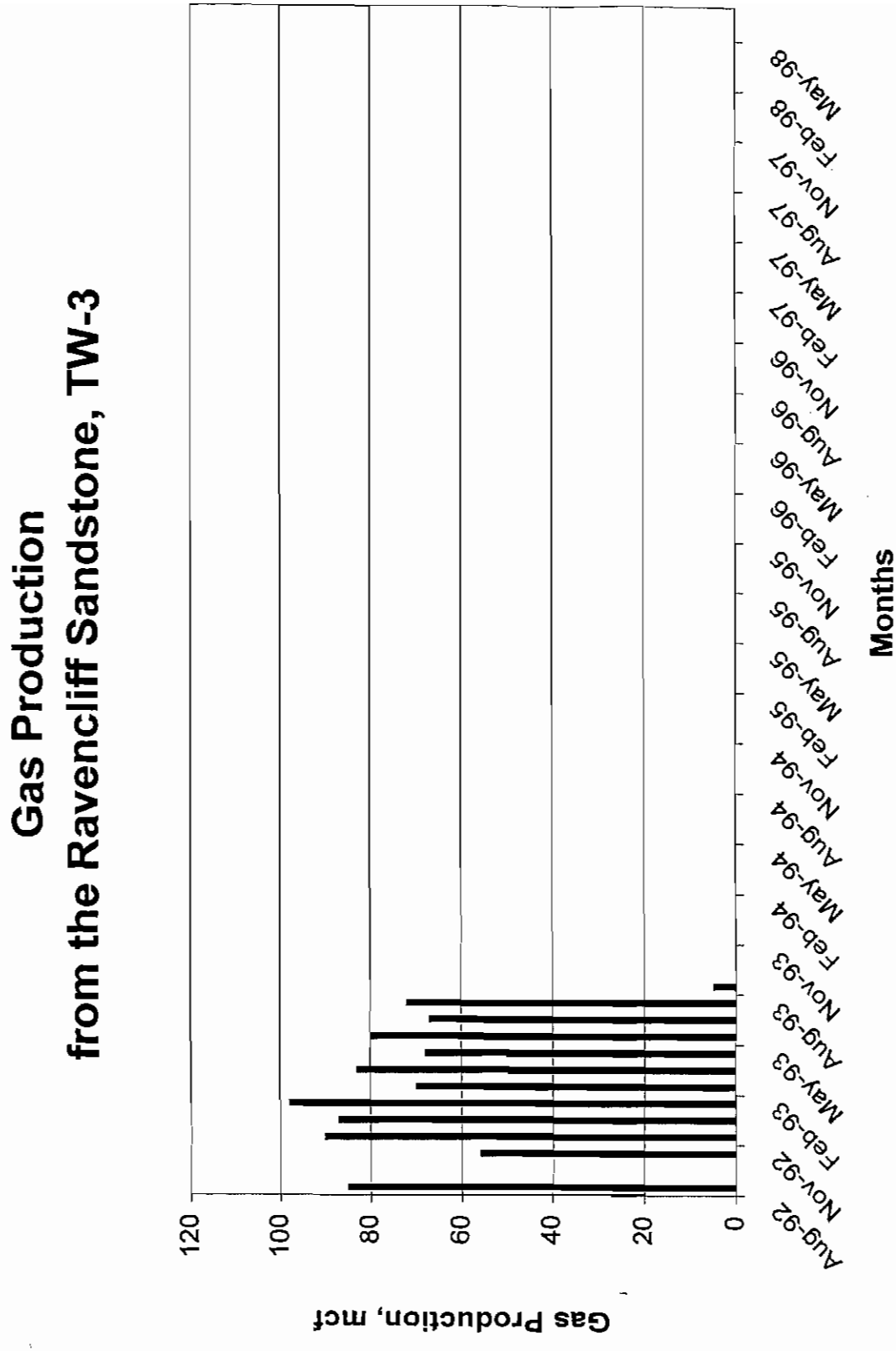



Figure 13.3.1 - Monthly Gas Production from the Ravencliff Sandstone in TW-3

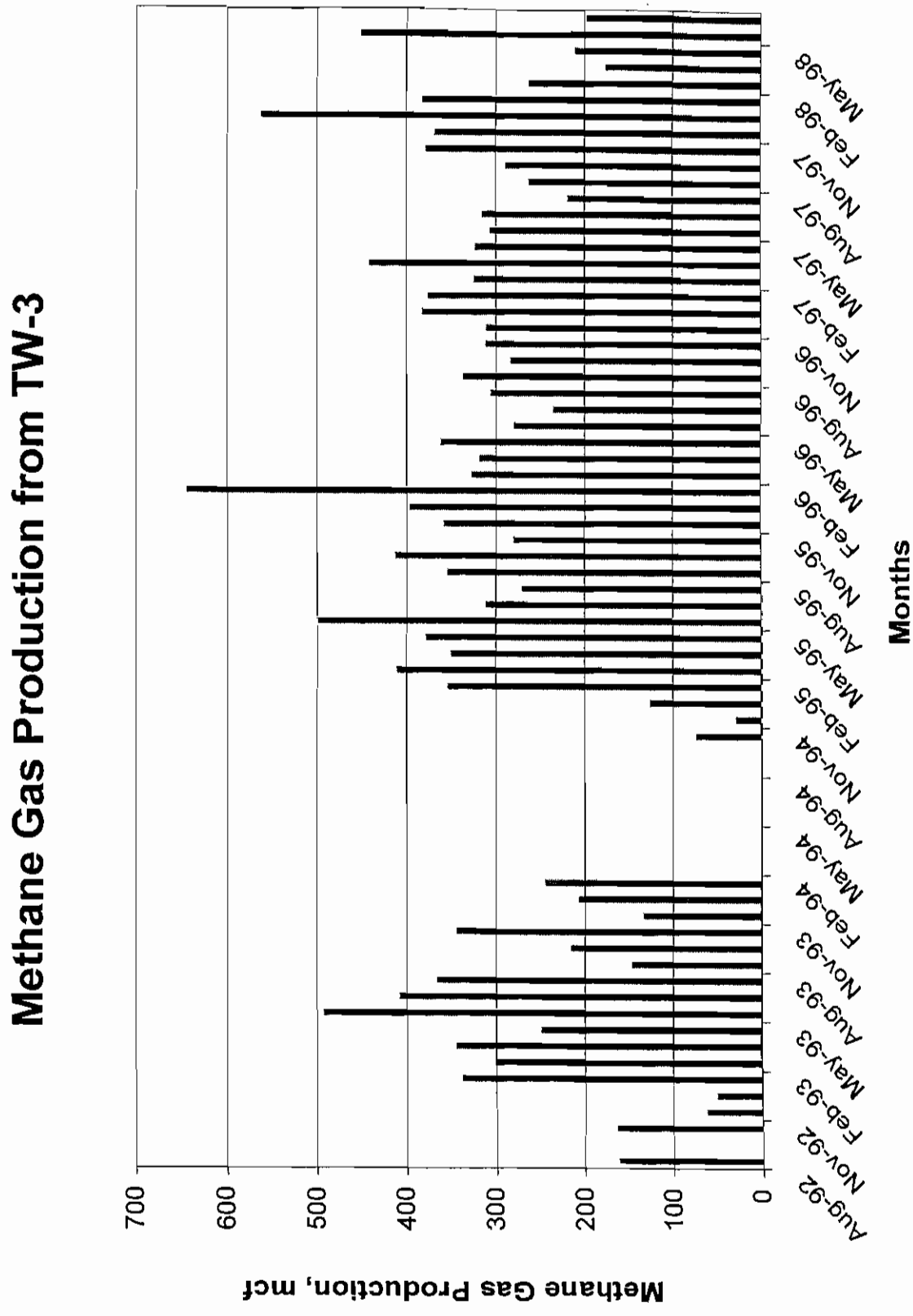



Figure 13.3.2 - Monthly Coalbed Methane Gas Production from TW-3

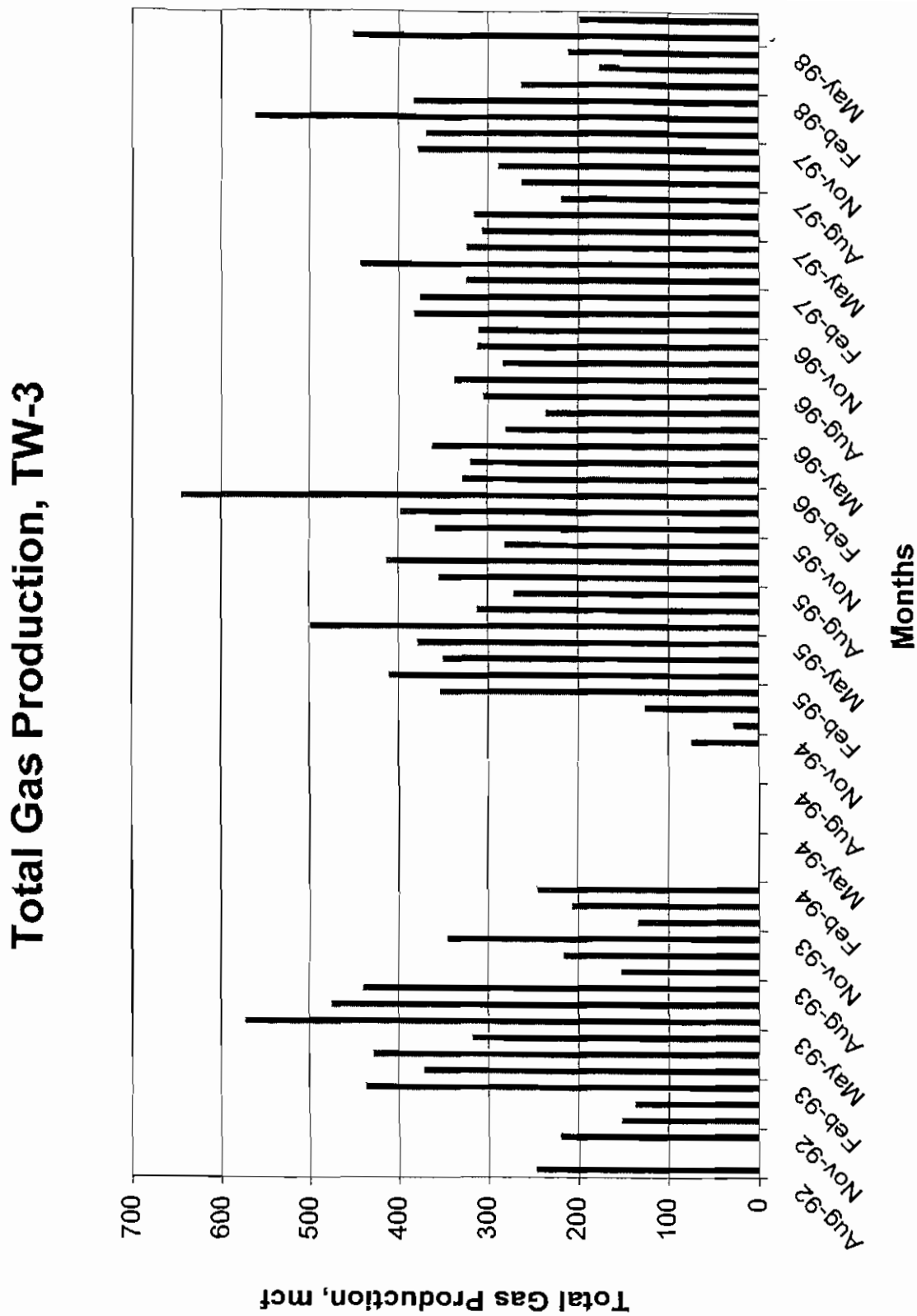



Figure 13.3.3 - Total Monthly Gas Production from TW-3

100 amp weather proof switch mounted on 6x6x20-foot pole on the well site. The power line was run up the access road from tree to tree.

### 13.3.3 Water/Brine Production Summary

There were numerous roadblocks to effective dewatering, just as with TW-1. Adverse weather conditions caused significant delays both in installation of the electrical hardware and in operation of the pumping system. Vandalism has been a much more persistent problem on TW-3 than on TW-1. There have been several instances of damaged or ruined motors and panel boxes, cut power lines, and broken power poles. In spite of these difficulties, TW-3 has remained a fairly consistent coalbed methane producer (see Figure 13.3.2).

As with TW-1, the progressive cavity pump originally installed on this well in March, 1993, was beset by the danger of having a small amount of fluid to pump combined with particles and solids downhole. As a result, the PC pump was twice damaged in the first year and required replacement.

When TW-3 was reworked in November, 1994, a new main breaker, control box, and meter base had to be installed as the former ones had been ruined by vandals. Also at this time, a decision was made to switch this well from the progressive cavity pumping technology to a standard bottom hole pump jack. This work was completed in December 1994. In March, 1995, the control box and wiring to the motor were stolen. In an attempt to counter this vandalism, the replacement box was mounted directly on the unit and wired underground to the overhead service point at the edge of the location. This provided thieves and vandals fewer access points to the equipment, and at least would force them to work a little harder to do their damage. The unit has operated virtually trouble free since that time.

The current surface equipment includes a pump jack, a 3-horsepower, 1750-rpm single-phase motor, and control box with 24-hour/15-min incremental timer. A description of the motor settings/components include unit speed of 11 rpm, gear box ratio of 34:1, motor sheave 3.75-inch, and gear box sheave of 20 inches.

Downhole the well is equipped with 2-3/8 inch tubing set at 1359.58 feet, with the pump intake at 1323.55 feet. The producing coals are located at about 1220 to 1250 feet. This affords a suitable rat hole or working space for the pumping process. The pumping schedule has been adjusted widely over the life of the well, just as with TW-1, in an effort to achieve optimum dewatering and gas production. Obviously, the pump jacks now placed on TW-1 and TW-3 allow much greater flexibility in pumping schedules and rates since the danger of catastrophic consequence is eliminated. A typical pump schedule for TW-3 is to pump at a cycle of 1 hour on and 3 hours off, around the clock.

The last fluid levels taken by shooting echometer test showed the working fluid level at 37 joints from the surface, or at a depth of 1185 feet. This places the maximum fluid level only 138 feet above the pump intake and provides for effective pumping efforts.

In looking at the history of the pumping system on TW-3, the performance of the pumping

system has been far superior to that on TW-1. The pumping system was operational about 620 days out of 910 possible days from November 1992 through December 1995. Therefore dewatering on TW-3 was being effectively performed about 68% of the time, compared with 39% on TW-1. After factoring in imposed shut in days, the actual operational pump time was closer to 63%, compared with 31% on TW-1. As of June 1998, these percentages have improved to 70% and 32% respectively

As with TW-1, the fluid produced from the coal zones is fresh water and is typically collected in a 100 bbl tank for measurement. When the tank is full, the water is then dispersed to the ground. Considering approximately 1337 actual pumping days with an average of 5.1 bbls per day, this yields 6800 barrels of water produced from the coals over the life of the well. When swabbing and direct land application periods are also factored in, the actual amount is probably closer to 7000 barrels.

### 13.3.4 Workover Activities: July - August 1993

There were two main objectives for this workover of TW-3: (1)plugging off the Ravencliff Sandstone formation, and (2) adjusting the placement of the progressive cavity pump downhole. Workover field activities were conducted July 29 - 30, and August 16 - 22, 1993.

Fluid levels for each zone were determined prior to working over the well. An echometer shot on the Ravencliff zone indicated fluid level appeared to be at 1452 feet, or about 338 feet above the top of the Ravencliff. The echometer showed fluid level on the coals at 798 feet, or 415 feet above the Poca #3 coal. The crew then rigged up. pulled, and inspected the tubing strings, pump assembly, rods, and tallied all parts downhole. A good deal of wear was found on collars and threads, resulting in difficulty with collars locking when running the 1-1/2 inch tubing back in the hole. The Ravencliff was swabbed with six runs and 15-3/4 barrels were recovered. Swabbing the coals brought very little water, 1-1/2 barrels in 3 runs. The coals had been vented to the atmosphere the day before and were producing at rate of 16.5 mcf per day before swabbing. After the first run, gas increased to 23 mcf; after second run, gas increased to 35.5 mcf; and after the third run to 39.5 mcf.

It was discovered during this period that two joints of 1-1/2" had been left out of the hole at some point in the past, presumably during completion activities. As a result, the pump intake previously had been landed just above the perforations at the Poca coal seam. This may have been the cause of many of the gas interference and pump-off problems experienced during the first year of the production test period. To correct this problem, the pump was set 60 feet below the Poca coal to provide additional rat hole for better dewatering.

Attention then was focused on the Ravencliff Sandstone. This formation had proved to be uneconomical with gas production of 2 mcf and brine production of 15 barrels per day. All plans and paperwork had been completed to plug the zone off, but a
second experimental option was selected -- to open the hole up completely rather than plug off the deep zone.

The tubing and rods were were pulled out of the hole, and the 4-1/2 inch casing was cut at

1413 feet and removed from the hole. This would allow the water from the coal seam to simply fall downhole and enter the Ravencliff. Preliminary calculations indicated that the Ravencliff formation would accept the coal water, thereby eliminating the need to pump, produce and dispose of the coal water on the surface. Gas production, however, began to decline steadily in the months following this effort.

Daily field reports for this workover can be found in Appendix 14.8

### 13.3.5 Workover Activities: October 1994

Numerous field activities were conducted from September 26 through October 19, 1994. This workover of TW-3 followed a long shut-in period from January 27, 1994, through September 30, 1994. This extended shut-in period came as a result of a legal dispute with Ramco Gas Company, into whose system these Project wells delivered their production. The primary thrust of the workover was the installation of a compressor on the entire well system. The activities specific to TW-3 related to plugging of the Ravencliff zone (as followup to the August 1993 workover described above).

A service rig moved on site October 11, 1994, and pulled the 1-1/2 inch string, the 2-3/8 inch string, the 5/8-inch rods, and the pump unit out of the hole. Shut in pressure was 180 psig before work commenced. The wireline service set a bridge plug at 1600 feet in the 4-1/2" casing by locating collars at 1579' and 1622'. Top of the cement was located at 1540 feet. The pump was reset at 1322 feet.

The tubing was run back in the hole in the following manner:

| | |
|---|---|
| 1 -- 1-1/2" O.D. mud anchor | 33.05 |
| 1 -- 1-1/2" O.D. perforated joint | 1.20 |
| 1 -- 1-1/2" Seating nipple | 1.30 |
| 1 -- 1-1/2" O.D. pup joint | 4.00 |
| 1 -- 1-1/2" O.D. PC pump | 3.20 |
| 41 -- 2-3/8" joints O.D. EUE tubing | 1322.00 |
| Bottom of Tubing | 1364.75 |

A 1-1/2 inch standing valve was installed in the seating nipple below the pump as the tubing was run. Fifty-two 5/8-inch rods were run with the pump rotor, seating the pump and drive unit before the rig was released.

### 13.3.6 Workover Activities: December 1994

This workover was a followup to the activities conducted in October as discussed in the previous section. The purpose was to pull the progressive cavity pump and install a standard bottom hole pump jack on Test Well 3. In so doing, both TW-1 and TW-3 would be

dewatered using pump jacks.

Rigs and crews arrived on location December 27, 1994, and pulled the 5/8-inch rods and PC pump rotor. They then pulled 1365 feet of 2-3/8 inch EUE tubing and the PC pump stator. The 2-3/8 inch tubing was returned back in the hole as follows:

| | |
|---|---|
| Tail pipe | 32.20 ft |
| Perforated joint | 3.00 |
| Seating nipple | 0.80 |
| 41 joints | 1314.35 |
| Pup joint | 10.20 |
| TOTAL | 1359.55 ft |

The following day the shut in casing pressure was 20 psi. The well was swabbed through the 2-3/8 inch tubing for 2 hours recovering 12 barrels of water. Casing pressure increased to 80 psi. Then the 2-inch x 1.25-inch x 8-ft. bottom hole pump was run downhole with a 1-inch x 10 feet gas anchor. Total rod length was 1310 feet. The pump was seated in the tubing and the rod string was raised 18 inches.

On the surface, the gravel pad was leveled for the pumping unit foundation. The unit was then set on timbers, aligned with wellhead and leveled. The beam counter weights and 3 horsepower motor were put in place and the service rig was released. Shut-in casing pressure was measured at 125 psi prior to placing the well on production. Well pumping was then initiated and the gas was turned in line. The well pumped to fill the tubing in 65 minutes, and then produced 1.7 barrels in the following hour. The well was then placed on automatic with a cycle of 45 minutes on and 4 hours off. Initial flow rate from the coals was 35 mcf per day rate with 17 psi line pressure.

Over the next few weeks, the pump schedule and rate were continually modified to see how it would affect gas production. Since the 45 minutes on / 4 hours off cycle saw gas production drop to 5 mcf per day after a few days, the pump time on was gradually increased. By January 18, 1995, gas production was holding at 12 mcf per day rate with the pump set to a cycle of 5 hours on and 7 hours off.

### 13.3.7 Gas Production Summary

Gas production from the Ravencliff Sandstone was poor from the very beginning, totalling only 775.5 mcf from August 1992 until the zone was abandoned in August 1993. The coals, however, have demonstrated a consistent level of production throughout the production test period.

Not surprisingly, the monthly lows in coal gas production correspond to the months when the pump system was not operating. According to chart integration records, the highest gas production months occurred in January 1996 (645 mcf), May 1995 (499 mcf), and May 1993

(493 mcf). The lowest monthly total was 29 mcf in November 1994, one of the months when the pump system was malfunctioning. The average monthly production from the coals over the life of the well has averaged 276.5, more than double the TW-1 coals (130.5 mcf).

Viewing the production in daily terms, the coals have averaged 10.0 mcf per day. This is determined by dividing the total coal gas produced (18,806 mcf) by the number of days in the production test period (1,887). This does not include the shut-in period resulting from legal dispute from January 27 to September 30, 1994.

## 13.4 TEST WELL 4

### 13.4.1 Drilling Activities

Site prep work for Test Well No. 4 (TW4, API Permit No. 47-081-1000) was initiated May 22 and completed May 31, 1995. The rig and casing were moved on site June 4 and the well was spudded June 5, 1995. Casing consisted of 13-3/8", 8-5/8", and 4-1/2". Total depth of 1545 feet was reached on June 9, 1995. About 15 feet of Pocahontas #3 coal was encountered that looked promising for gas production. Density and gamma logs were run and the well was shut in pending implementation of the stimulation plan.

Following analysis of well logs, three coals were identified for stimulation: (1) unnamed coal (possibly Sewell) at 1351 feet; (2) Poca #3 coal at 1255 feet; and (3) Beckley coal at 994.5 feet. Based on these findings, a three-stage foam/sand fracturing program was designed.

### 13.4.2 Stimulation Activities

A service rig was moved on location August 7, 1995, and cement bond and correlation logs were run inside the production casing. In preparation for stage #1, the 4-1/2 inch casing was perforated from 1351 to 1352.5 feet with 9 holes. Breakdown of the zone was accomplished with 300 gallons of 15% HCL and nitrogen at a pressure of 3491 psig. The zone was fractured with 1500 lbs. of 20/40 sand in 110 barrels of foamed water. Average pump rate was 11 bpm at an average treating pressure of 3305 psig.

The casing for stage #2 was perforated at 1255.5 to 1257.5 feet (15 holes), 1265 to 1265.5 feet (3 holes), and 1284.5 to 1285.5 feet (6 holes). A frac baffle was set at 1290 feet by wireline. The zones were broken down with 500 gallons of acid at 3300 psig, and foam fractured with 5000 lbs. of 80/100 sand and 25,500 lbs. of 20/40 sand in 213 barrels of foamed water. The average rate was 19.2 bpm and the average treating pressure was 2082 psig.

The casing was perforated for stage #3 from 993.5 to 999 feet with 33 holes. When the perforating gun was fired, the gun and collar locator were lost downhole and operations suspended temporarily. The lost gun was recovered by a fishing tool on August 9, 1995. Sand fillup was measured at 1000 feet, and the well was opened to the pit and flowed for two hours to remove the sand. The zone then broke down at 3242 psig with 500 gallons of acid, and was foam fraced with 8900 lbs. of 80/100 sand and 3100 lbs. of 20/40 sand. The average rate was

20 bpm and the average pressure was 2824 psig. The well was left to flow through the 2" line overnight.

The Stage #1 coal was thin and did not respond well to stimulation. Indications were that this zone would not contribute to the well's productivity. The Stage #2 coal responded well to stimulation and should be the prime producing zone for this well. Stage #3 was more than five feet thick but was difficult to frac due to high treatment pressures.

The well was swabbed through the 4-1/2" casing on August 14, 1995, and 10 barrels were recovered in three hours. 2-3/8" tubing was run with bottom at 1348.28 feet and a seating nipple at 1313.98 feet. The well was swabbed through the tubing and shut in. A rod type bottom hole pump and sucker rods were run into the hole on August 15, 1995. A 100-barrel storage tank was placed on location and pumping was initiated.

The pump jack was operated throughout August and September using an 8 hp gasoline powered engine until the site could be automated. Water production initially averaged 3 - 4 barrels per day and gas production 2 mcf per day. The water continued to slowly increase while the gas dropped to 0.

### 13.4.3 Site Automation

Efforts continued through the remainder of 1995 and through January 1996 to electrify Test Well 4, but were met with a variety of barriers. First there were difficulties finding qualified electricians to perform the work. The electrician who had repaired the system on TW-1 in mid-1995 was unable to continue working on the Project due to other obligations.

Then the most insurmountable obstacle proved to be the severe winter weather. High snowfall amounts and continued extreme cold prohibited automation of the site. A day or two of work clearing the right of way had to be pieced together over a period of weeks and months. Finally, in early February, 1996, the electrician's work was finished and the power company completed the service drop.

The electrical work was similar to that on TW-1 and TW-3. A treated power pole was set with a 100-amp outdoor switch box wired to a power company meter base. A thirty-foot right-of-way was cleared up the hillside to set 10 poles and hang wire. About 2000 feet of #2 triplex was used with the line buried once it reached the edge of the site.

The well had remained shut-in for most of the four-month waiting period, and by the time the electrical pumping system was activated on February 7, 1996, the well seemed to have lost its promise. Since automation, water production has steadily increased while gas production has rarely registered above zero. Water production through February and March 1996 has been about 3.3 barrels per pump hour, or generally in the range of 70 to 80 barrels per 24 hour period.

A number of things have been tried including (1) alternating pumping schedules and rates; (2) varying the motor speed; and (3) pinching back and blowing the well zone. None of these

attempts to "tweak" the well have been successful. It seems that the zone has flooded out, perhaps now pulling water from the old works of the abandoned New Beckley Mine. The only recourse might be to isolate the two coals, the Beckley and the Poca #3, and confirm if the majority of the water is coming from only one zone. If so, that zone could be sealed off and gas production could perhaps be resumed from the other coal.

## 13.5 COMPRESSOR

### 13.5.1 Compressor Description

As a vital part of the experimental research aspect of this Project, a decision was made to install compression on the entire well system. The purpose was to observe the effect of compression on these wells. Since atmospheric flow tests showed that the coals in each well were basically capable of producing 35 mcf per day, it seemed logical that some acceptable percentage of that number might be achieved by installing compression and pulling the pipeline gathering system down to near-0 psi.

A willing partner was found in Peake Operating Company who was willing to allow the College to install a compressor and tie directly into their gathering line. The compressor site was conveniently located at the base of the hill at the TW-1 site.

A Dearing Model 390 Gas Compressor was selected with two-stages, two-cylinders, air cooling, pressure lubrication of the power frame, a low compressor oil pressure shutdown switch, suction unloading valves, a v-belt drive assembly with OSHA approved guard, and a discharge pulsation bottle.

The engine was a Ford 140 CID natural gas power unit, water cooled, with metal enclosure side panels, radiator, 12 VDC electric starting and charging system, throttle, clutch PTO, Murphy safety switches for low oil pressure and high water temp, fuel bottle, fuel gas regulator, battery and muffler. The unit was rated 29 hp @ 1800 rpm.

The control panel included load/unload operation controls, an Asco solenoid valve, and Allen-Bradley pressure switches for suction and discharge pressure control. Also included was a Murphy control panel, two OPL-FC suction and discharge pressure Switchgauges, one 5T timer, and seven Tattletales.

### 13.5.2 Compressor Installation

Once the negotiations were complete for access to and use of a site for the compressor, installation began on September 29, 1994. Work continued over the next few days including cutting into the existing Peake gathering line and installing a 2-inch T and valves at the tie-in point. Then 800 feet of 2-inch plastic pipe was laid to the compressor site. Peake's portion of the tap process was also completed and all parties were prepared for the tap on October 3, 1994.

The following day, October 4, 1994, the compressor was delivered, set in place and leveled on gravel pad. The Project Team connected the 2-inch suction and discharge lines, a 2-inch bypass line, and a 1-inch connection on the suction line for low pressure fuel provision.

On October 5, 1994, the orifice sales meter was then transferred from its old location (at the Ramco tap point) to the new compressor site near Peake Well #703. The discharge line was then tied in to the meter inlet, and the meter outlet was tied to Peake's tap line. The next few days consisted of workovers on the three wells and other miscellaneous preparatory tasks.

On October 10, 1994, the final check was conducted of all compressor components and fluid levels. The compressor was started at 2 pm, and at 5:30 pm readings showed 5 psig suction, 40 psig discharge pressure, and 75 mcf per day gas production rate at the main sales meter.

On October 11, 1994, readings showed 4 psig suction pressure, 45 psig discharge pressure, and 62 mcf per day rate. The system was then shut down to re-level the compressor and repair pipeline leaks. The rubber discharge hose had to be replaced with a steel pipe. Over the next few days, an eight-foot-tall chain-link fence enclosure was placed around the compressor.

The first month of compressor operation involved routine maintenance (oil and filter changes, etc) and adjustment of the pressure settings and motor speeds. It was necessary to massage the system to find the optimum settings for the discharge and suction pressures in conjunction with the rpm setting of the motor. Improper balance between these items causes excessive vibration of the unit and spiking on the well charts.

Experiments with the motor speed were conducted by varying the rpm settings from 1050 to 1300. It has been found that the system performs best at 1175 - 1200 rpm. Suction pressure should typically be set at 1 - 3 psi, with discharge near 40 psi. Suction pressure of 1 psi at the compressor usually translates to about 6 to 7 psi in the field at each well site. Therefore, with this arrangement and the physical distances involved, it is not possible to achieve true atmospheric pressure at the wellhead. The coals are feeding against 6 to 7 psi rather than zero psi.

### 13.5.3 Effects of Compression

By assessing the production amounts shown in Figure 13.5.1, it seems that the effect of compression on coal gas production has been minimal. No doubt it has helped production, but not as much as had been anticipated. It seems clear that coal gas production in the Project wells is much more a product of effective dewatering than of compression. A compressor is, however, a necessity in this and other situations to allow tapping into existing, local gathering systems.

The compressor also becomes a critical point of the well system; all the wells behind it depend on its continued performance. Problems with the compressor may mean a shut-down of production from the wells, winter weather being a prime cause of such a scenario, as the compressor has a number of components that can fall victim to adverse weather.

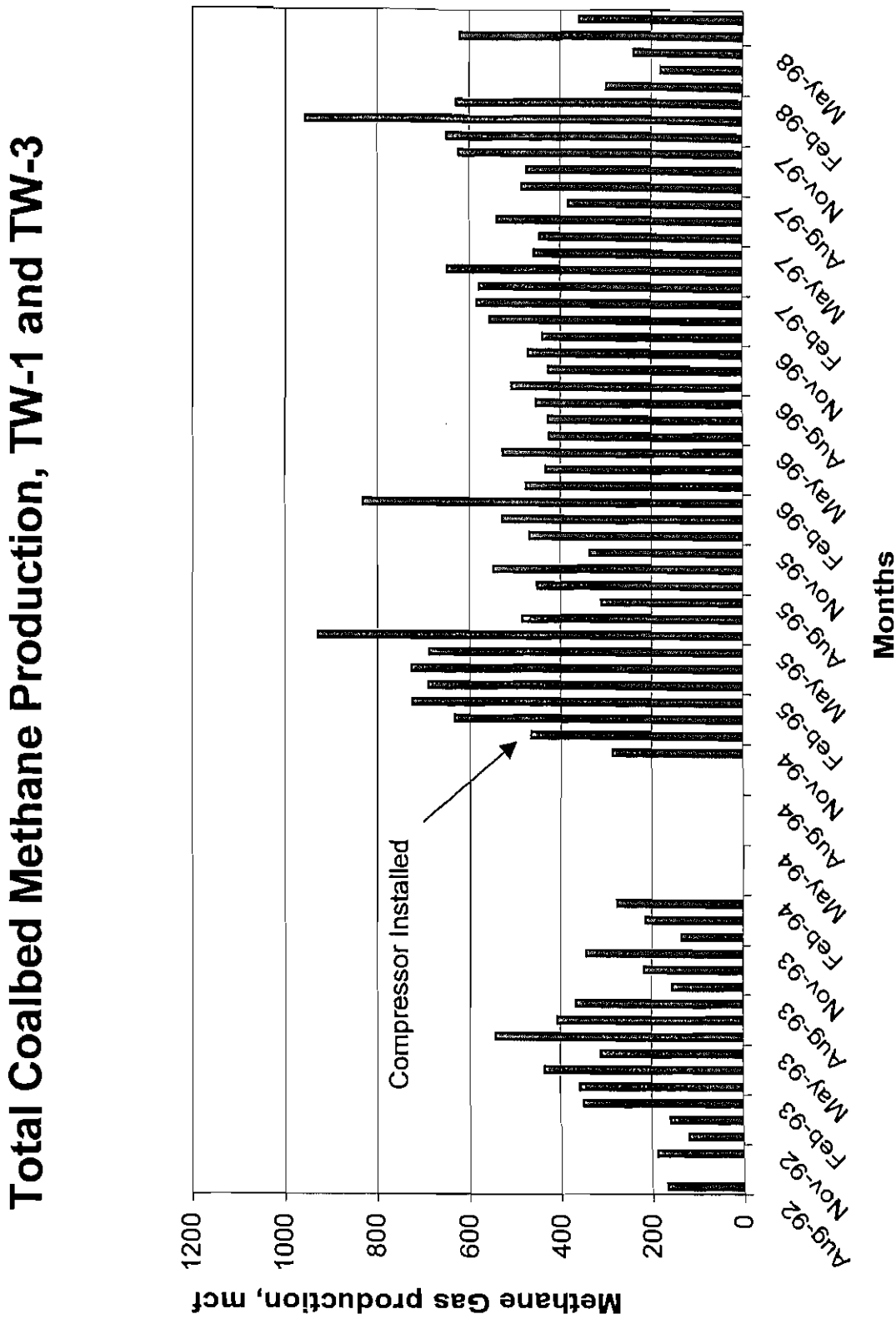



Figure 13.5.1 – Coalbed Methane Gas Production from TW-1 and TW-3

## 13.6 FACTORS AFFECTING GAS AND METHANE PRODUCTION

As in the case of virtually every oil or gas well in existence, there are three main categories of factors which control production at the Multi-Strata Project site: Reservoir conditions, mechanical production systems, and operating practices. Gas production from the multi-strata project is further complicated by the fact that each of the four different reservoirs (Big Lime, Ravencliff, Pocahontas Coals, and Beckley Coal) are significantly different, have different mechanical requirements, and require different operating practices.

### 13.6.1 RESERVOIR CONDITIONS

Clearly, the best reservoir(s) in the project area, based on gas production, are found in the Big Lime formation. The Big Lime, being deeper and generally higher in pressure than the other three reservoir types, contains more gas and is better able to deliver the gas to the pipeline. Big Lime wells, when properly located on structural highs, have very good reservoir properties.

The Ravencliff sandstone reservoirs were found to vary in quality, were also dependent upon structure for gas accumulation, and were more dependent upon depositional environment than structure for their permeability and porosity. A significant gas-producing formation in the project area, the Ravencliff was definitely worthy of consideration as a potential contributor to the multi-strata development program. In TW-1, the Ravencliff provided a significant amount of gas, but its actual contribution could not be accurately determined because its production was co-mingled with that of the Big Lime.

The coal seams, although relatively shallow and low-pressured, contributed significantly to the total gas production. Of the 109 million cubic feet of gas produced during this study period, some 29 million cubic feet was coalbed methane. This is about 26 percent of the total. During the latter months of the study period, the coal bed methane contribution has risen to about 31 percent. This increase in percentage is probably due to a combination of factors including automation of the pumping systems, dewatering of the coal seams, lower line pressures (compression) and overall-improved operations. The Pocahontas coal seams are clearly the better gas producers, but the Beckley seam has better reservoir characteristics, except for high water saturation and (possibly) a low methane content in the vicinity of the project. The low-gas, high-water productions observed for the Beckley seam is probably due to the project's proximity to a recently active mine. Methane production from the Beckley at locations away from the mining operation would likely be similar to that from the Pocahontas seams, at least in the early stages of production.

### 13.6.2 MECHANICAL PRODUCTION SYSTEMS

Each of reservoir types require different mechanical assistance for production. The Big Lime requires the least assistance; for example, a foamed-acid treatment in selected zones coupled with a string of tubing in the wellbore to make it easier to remove produced water, proved to be adequate for TW-1. Plunger lift equipment installed at TW-2 had marginal success in increasing production from the Big Lime.

The coal seams also required stimulation by hydraulic-fracturing, as well as pumping systems for water removal. Pumping systems were required because the methane gas was stored in the coal by adsorption. The gas could not be produced until enough water was removed to lower the coal seam pressure to a value substantially below the adsorption equilibrium pressure. Additionally, the coal seam water saturation had to be reduced, with corresponding increase in methane gas saturation, for the gas to flow into the wellbore.

Obviously, water removal and the mechanical systems facilitating removal are critical to successful methane production. Figure 13.6.1 shows the average TW-3 methane production rate in relation to water production rate, and appears to indicate that an optimum rate of water production exists at about 3 to 5 bpd; however, this is not a true picture of the situation. The higher water production rates (8 to 20 bpd), with somewhat lower gas rates, is indicative of a relatively high water saturation in the coal seam. This is a condition that exists early in the life of a well and must be altered by pumping the well at its maximum rate. While pumping is absolutely essential in this situation, fluid production is dominated by the reservoir condition. The lower water production rates (0 to 4 b pd) reflect one or a combination of two possible scenarios: Either extensive pump downtime during a given month has caused the average rate to be low, or the water saturation has fallen to a level where the coal seam is simply incapable of producing water at a high rate. Once the latter condition is reached, then both gas production and water production are direct functions of effective pump time as shown by the graph in Figure 13.6.2. Both factors, pump time and reservoir conditions, simultaneously impact methane production, but direct control can be exercised only on pump time

### 13.6.3 OPERATING PRACTICES

Operating practices include all field activities as well as engineering design and/or policy decisions which impact the field activities. Initial design decisions were weighted toward simplifying field operations so that most local oilfield personnel could operate the wells with a minimum of familiarization or training. There were no automation nor complex control systems; virtually every operation required implementation by a field hand. One possible exception of the simplicity rule, was the installation of a progressive-cavity, positive-displacement pump (PC Pump) in TW-3. This type of pump was commonly used for oil and gas production and for coal-dewatering in other areas, but it was not common to the industry in this area. The selection of the PC pump proved to be a mistake in that it was critical that the pump schedule be timed to pump as much water as possible without pumping it dry. This was necessary to avoid overheating and destroying the pump. The requirement proved to be too difficult in the face of declining and sometimes erratic water production rates. The eventual solution was to switch to conventional oil field pump jacks which were more familiar to local workers and which were less sensitive to being pumped dry.

Later in the project, the pumping systems were automated by installing electrical power at the sites and adding electric motors with timers so that more precise and regular pump schedules could be maintained. This proved to be generally beneficial, but not without problems. More

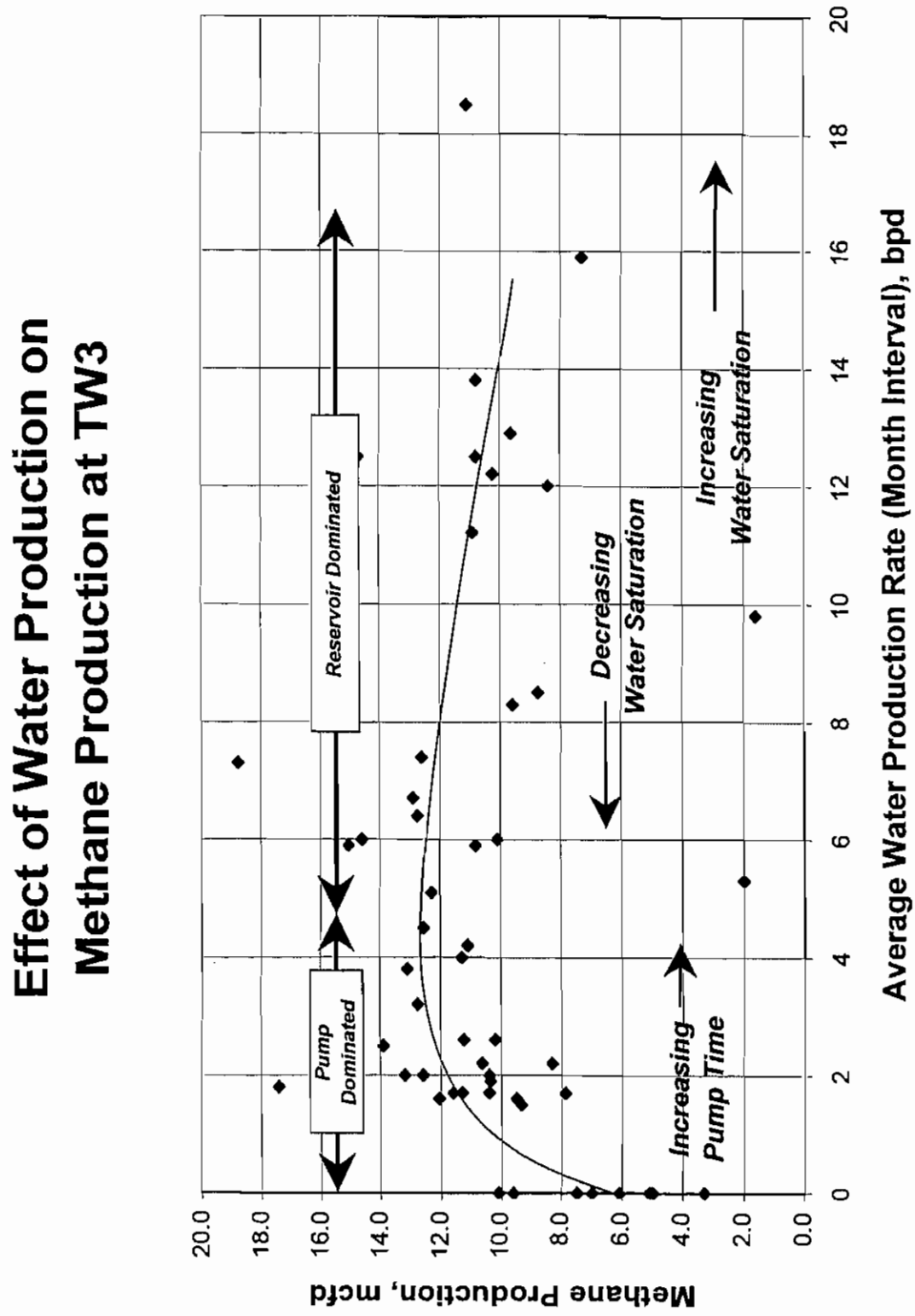



Figure 13.6.1 – Comparison of Average Methane Production Rates with Average Water Production Rates in TW-3

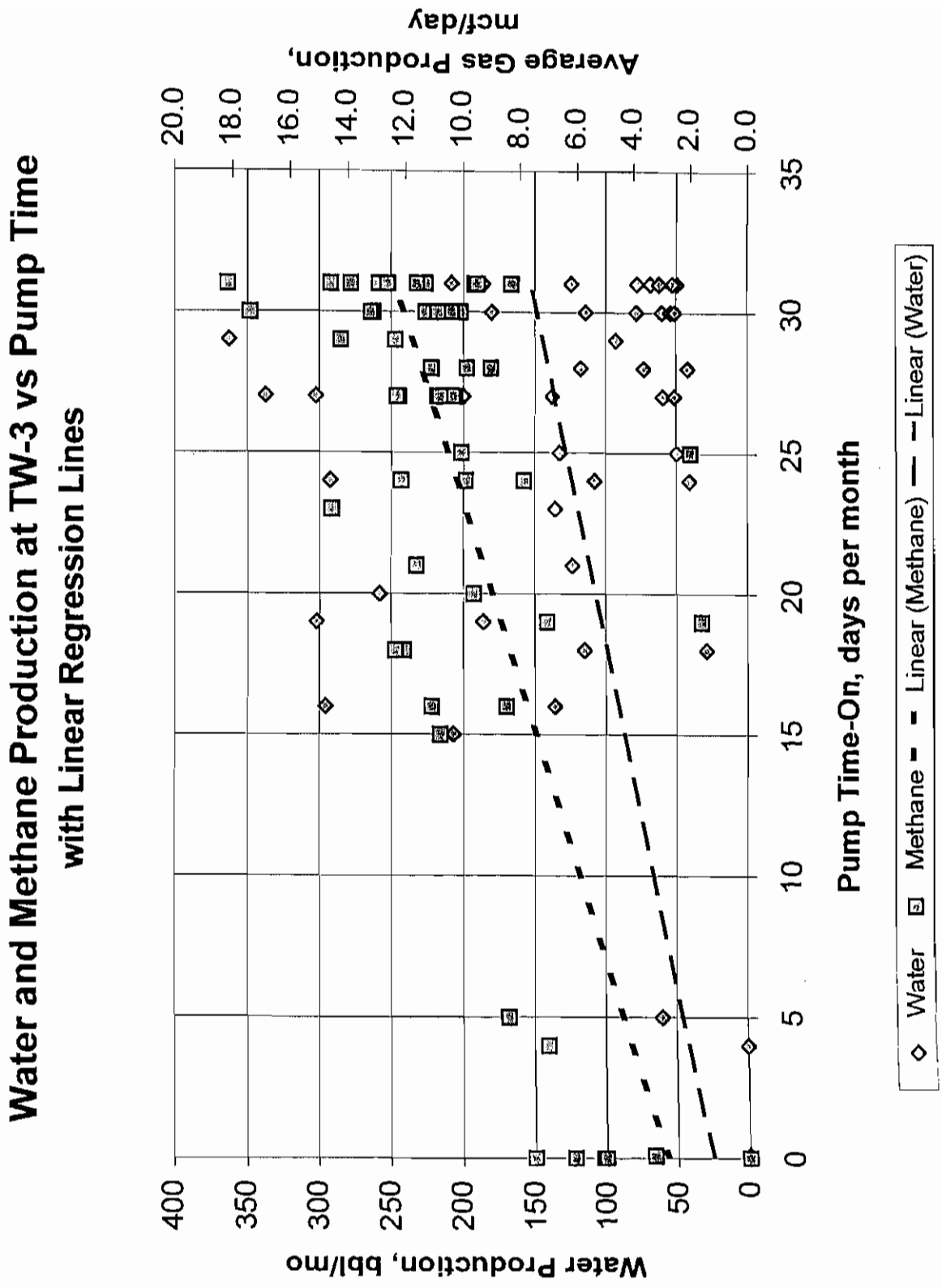



Figure 13.6.2 - Water and Methane Production at TW-3 versus Effective Pump Time

efficient coal dewatering was then possible, but it did not eliminate the need for regular site visits by the well tender. Theft of equipment and materials from the site was common enough to cause significant downtime. Weather was also a significant cause of equipment malfunctions and breakdowns, necessitating regular site inspections and maintenance.

Other modifications to equipment and operating practices were the implementation of a plunger lift system at TW-2 and the installation of a compressor. The plunger lift provided much more efficient lifting of the water from TW-2 and demonstrated considerable potential for increasing gas production from the well. The compressor was a significant improvement to the production system, due to reducing wellhead producing pressures from previous averages of 20 to 40 psig to more consistent pressures in the range of 6 to 10 psig. This reduction in wellhead pressure did not significantly affect production from the deeper higher-pressured formations, but had a beneficial effect on the production of methane and water from the coal seams. Addition of the compressor also provided better control of that function, since previously, compression had been provided by the gas transporter, who could not always be depended upon for prompt repairs. The compressor also added a significant maintenance and operation burden to the project by requiring dedicated attendance of frequent intervals to be sure it was operating properly and had adequate lubrication. The compressor was designed to operate continuously, and required frequent resupply of oil to its automatic lubricator.

Efficient and affective well tending has proved to be a very significant factor in maximizing gas production from the project. This was demonstrated, (hopefully, exaggerated) by frequent severe winter-weather conditions that caused flow lines to freeze, equipment to break down, and well tenders to be delayed or prevented from effectively servicing the wells. Only through near-superhuman efforts were the wells even visited during some of the deep snows and blizzard conditions that were experienced. Repairs and routine maintenance were even more difficult to accomplish under the existing conditions, and gas production suffered as a result. The winter weather experienced during this test period was exceptionally severe and would not be expected to occur every year at the same level of severity. Even so, it served as an important lesson that it is very important to have all equipment in the best possible condition and all hostile weather preventive measures in place at the beginning of the winter season. Such measures will not prevent 40-inch snow falls, but they may make the impact on production less severe

Although operational problems represented only one of the several causes of downtime, it was significant. Without the close attention that was provided by project well tenders, the problem could have been much worse. Figures 13.6.1 and 13.6.2 illustrated of the importance of minimizing pump downtime to enhance methane production. Although maximizing producing time is somewhat less important in the case of the higher pressured formations, it is still important. Figure 13.6.3 is a graph of total project gas production from all formations and all wells as a function of producing time. From this figure, it can be seen that holding downtime to no more than 5 to 10 days per month will result in near-maximum gas production.

### 13.6.4 ADDITIONAL OBSERVATIONS AND RECOMMENDATIONS

The mainstay of gas production for this project for many years to come, will be the Big Lime/Ravencliff production from TW-1. These two formations from this one well have

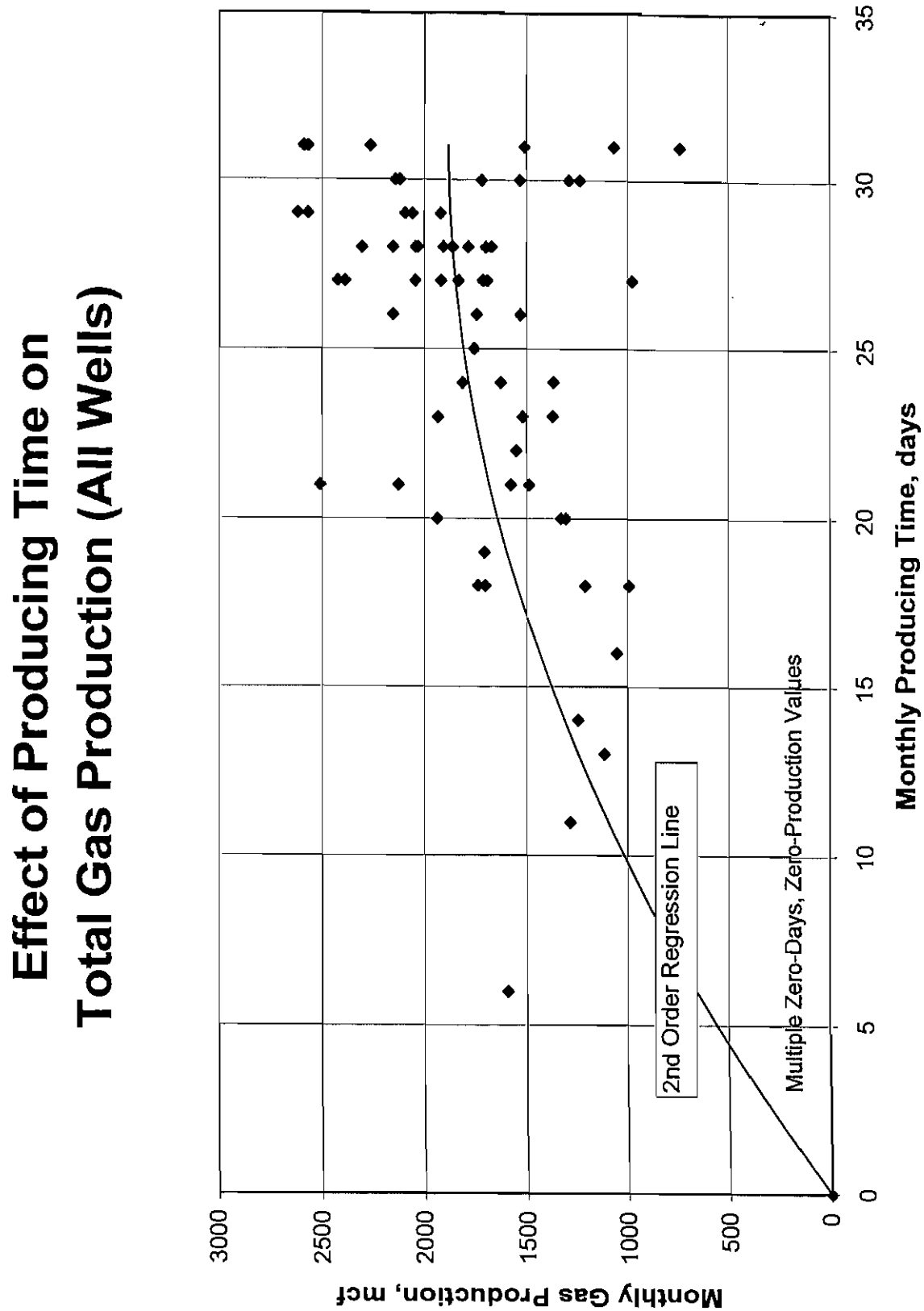



Figure 13.6.3 - Total Project Gas Production from All Formations and All Wells as a Function of Producing Time

consistently provided 60 percent of the total project gas. Figure 13.6.4 shows the exponential decline of production from the Big Lime and Ravencliff formations in TW-1. The rate of decline appears to be pleasingly low, only about 2.3 to 2.4 percent per year. The following equation should provide a reasonable estimate of production from these formations for the next 3 to 5 years, at which time the rate of decline should be re-evaluated.

$$\text{Production (Monthly)} = 1{,}180\ e^{-0.024t}$$

where t = time (years)

and t = 0 at January 1, 1993

Coalbed methane's percentage contribution to production has gradually increased and will probably continue to do so for a few years, especially if TW-4 can be made to produce. Big Lime gas production from TW-2, while not great, will likely remain consistent, possibly declining at about the same rate as Big Lime/Ravencliff gas production from TW-1.

TW-4 coalbed methane production has been disappointing. The reason for the poor performance to date is not clear, but the probable cause is either poor communication (flow blockage) between the wellbore and the coal seam(s) or by virtue of the well's down-dip location on the seam. To explore these theories, a series of tests could be run. The simplest test would be to pressurize the annulus of the well by injecting either gas (could be Big Lime gas from co-located TW-2) or a slug of water (possibly TW-4 water, if available, or coal water produced from nearby TW-3). By measuring fluid levels in the annulus, the rate of water intake could be determined as function of pressure differential, establishing the degree of communication between the well bore and the coal seam. If natural gas were to be used, the test should be continued until all water is displaced from the annulus, allowing the gas to enter the coal seam. This could provide better removal of any coal fines blocking the casing perforations and could additionally induce temporary gas saturation of the coal seam adjacent to the well bore. This temporary gas saturated zone would allow methane to be produced immediately following the test when the well would be placed back into production.

The importance of good maintenance and operating practices cannot be over emphasized. Excessive downtime was shown to reduce gas production. It is often tempting to reduce "unessential" maintenance and operating services in order to cut operating costs, but such reductions should be carefully evaluated with respect to their potential impact on future production. Such reduced services should be clearly "unessential". Well-tending, along with complete and accurate record keeping, should be emphasized so that informed operating decisions can be made without delay. The compressor, pumps, pipeline, and associated equipment must continuously be kept in good repair for maximum gas production.

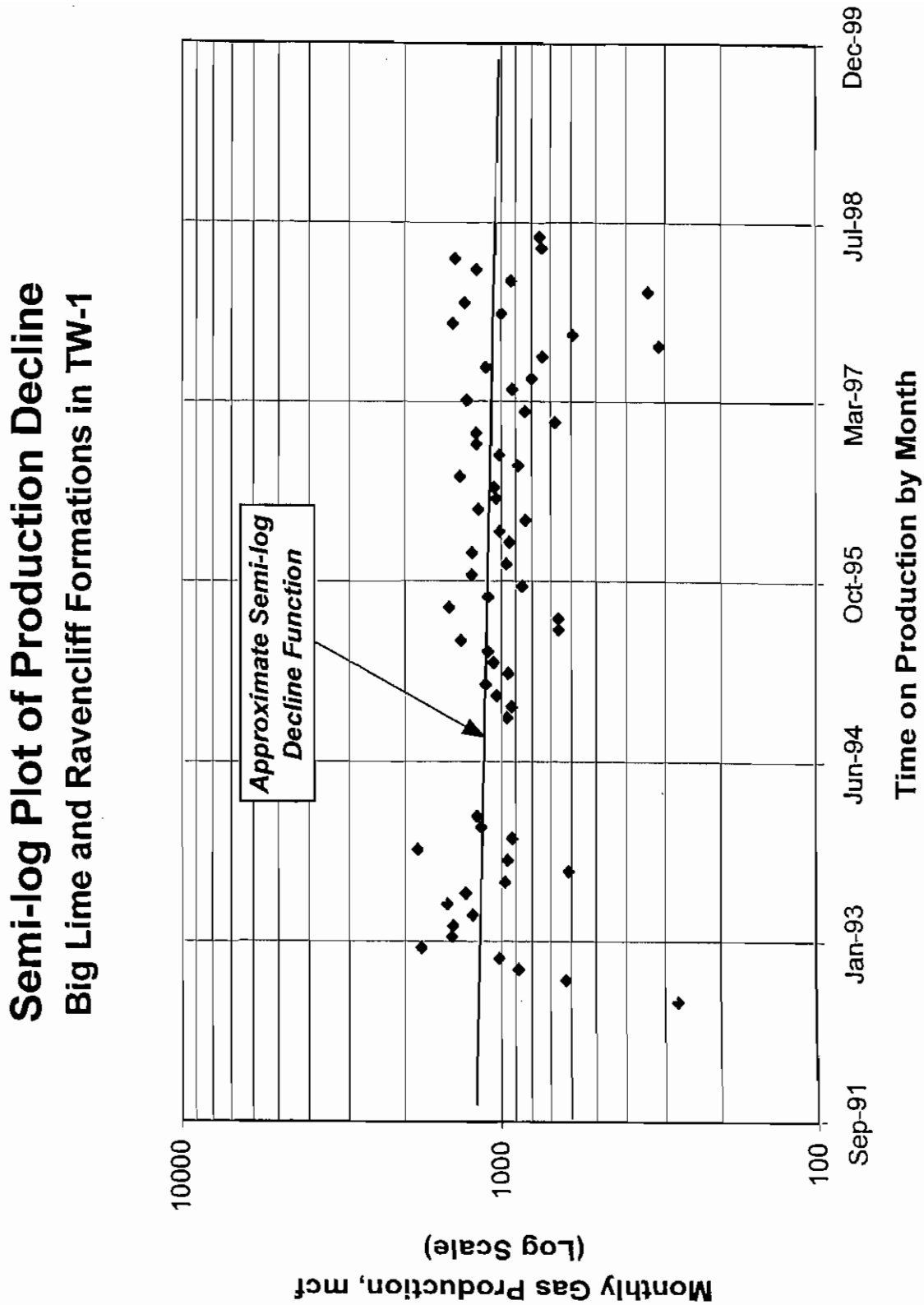



Figure 13.6.4 - Exponential Decline of Production from the Big Lime and Ravencliff Formations in TW-1