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MEASURING AND PREDICTING RESERVOIR HETEROGENEITY IN COMPLEX DEPOSYSTEMS

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APPALACHIAN OIL AND NATURAL GAS RESEARCH CONSORTIUM

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OBJECTIVES

Recovery of additional oil from existing fields in the Appalachian basin is hampered by poorly known permeability barriers within the reservoirs. Vertical barriers, due to stacking of sandstones separated by shale breaks, are relatively easy to recognize in a given well, but difficult to project laterally. Lateral barriers due to facies changes are more difficult to predict, and subtle changes within the reservoir due to diagenetic changes are the most difficult of all. Thus, several scales of heterogeneity exist, from those imposed by shifts in depositional environments down to the pore throat barriers developed during diagenesis. The result is that our oil reservoirs consist of a complex series of flow systems dependent on lithology, sandstone genesis, and structural and thermal history.

The proposed research is designed to use a multi-disciplinary approach to measure and map heterogeneity at various scales, and ultimately to develop tools and techniques to predict heterogeneity, both in existing fields and in undrilled areas. Two stratigraphic units have been chosen for this research. The Big Injun sandstone (Mississippian) in West Virginia, and the Rose Run Sandstone (Ordovician) in Ohio and Pennsylvania. The main objectives of this research are to:

1. Map the geometry of sandstone bodies within a regional depositional system and classify these bodies in a scheme of relative heterogeneity, thus determining the heterogeneity across the depositional systems.
2. Map facies changes within the given reservoirs, interpret environments responsible for each facies, predict the inherent relative heterogeneity of each facies, and share these results with petrologists and petroleum engineers.
3. Correlate structural variations with hydrocarbon production and variations in geologic and engineering parameters that affect production in Big Injun reservoirs in West Virginia.
4. Develop a reliable seismic model of the reservoir expressed in terms of impedance variation, such that physical heterogeneity within the reservoir can be interpreted.
5. Describe the pore types and relate them to permeability, fluid flow and diagenesis, and by integrating petrographic studies with facies and depositional environments derived from stratigraphic work, to develop a technique to use diagenesis as a predictive tool in future reservoir development.
6. Study the affects of heterogeneities on fluid flow and efficient hydrocarbon recovery in order to improve reservoir management and future development.

7. Apply graphical methods to production data, and develop new geostatistical methods to detect regional trends in heterogeneity.
8. Use the geologic and engineering data on Big Injun reservoirs in West Virginia to construct facies maps, and compute the local probability that new, in-fill wells will intersect rock with favorable reservoir characteristics.

The main goal of this research project is to understand reservoir heterogeneity sufficiently to predict optimum drilling locations versus high-risk locations in a given field in order to recommend the most cost-effective infill-drilling programs.

HETEROGENEITY IN THE BIG INJUN SANDSTONE

STRATIGRAPHY

Two papers were presented at the annual meeting of the American Association of Petroleum Geologists in New Orleans in April: (1) Reservoir heterogeneity of Big Injun sandstone in West Virginia: Stratigraphic (including diagenesis) controls on oil production in Granny Creek field; and (2) Seals, barriers, and compartments of fluvial-deltaic reservoir: Granny Creek field, West Virginia.

The influence of stratigraphic heterogeneity on primary oil production is summarized on Figure 1. The areas of Granny Creek field with the best primary production are shown in black and represent initial open flow (IOF) of greater than 25 barrels per day and cumulative oil production (COP) of greater than 25,000 barrels per 10 year duration prior to water flooding. These high oil production areas occur in a north-south belt about midway from west to east across the field. Lack of high oil production in the northernmost part of the field corresponds with the absence of the B member of the Big Injun sandstone, which presumably served as a seal for the oil accumulated in the proximal mouth-bar facies of the C member. The north-south belt of highest primary oil production occurs between two bracketing belts of lower oil production: (1)the eastern north-south belt where the C1 sandstone is overlapped by the C2 sandstone and separated by a thin shale low permeability barrier; and (2)the western north-south belt separated by another thin shale permeability barrier. The term "barrier" means that fluid flow is hindered and reduced but not totally stopped. The north-south belt of highest primary oil production occurs within the proximal bar facies (pay zone) of the C2 sandstone of the Pocono Big Injun. It also is important to note that this highest belt of production parallels the structure contours for Granny Creek field, thereby indicating an important influence of structure as well. Within the belt of highest primary oil production, the best production occurs in 13 patches (compartments) ranging in size from one to 29 acres and averaging 12.54 acres. The diagenetic density zones also act as partial barriers to fluid flow, are irregularly tabular, range 2 to 8 feet thick, cut across the bedding at a low angle, allow less pore space for oil accumulation, and occur nearly parallel to the overlying pre-Greenbrier unconformity. These diagenetic density zones have reduced permeability resulting from secondary quartz cementation and iron minerals. They occur between the areas of high primary oil production with 90 percent consistency and tend to compartmentalize the oil reservoir. These diagenetic barriers occur where the primary oil production is 8 to 10 times less than the "sweet spots" of highest production, a condition that attests to their lower permeability and value as partial barriers to fluid migration.

In the southern part of the field, a strong correlation exists between wells of high water injection pressures, low rates of water injection, and areas where the diagenetic density barriers occur. The two anomalies of highest water injection rates with the occurrence of the diagenetic density barriers are the wells that communicate (fractures connect wells causing rapid flow rates and low pressures). Secondary recovery data tends to support the conclusions concerning the stratigraphic heterogeneity of the Big Injun sandstone reservoir in Granny Creek field.

STRUCTURAL GEOLOGY

Maps and sections were integrated and finalized during the quarter. A preliminary draft of the final report was written.

In structural studies, a report (Appendix A) was written and illustrations were prepared which explains the unusual occurrence of synclinal oil in the several Big Injun fields in southern West Virginia.

In geophysical studies, arrival times of the Devonian Onondaga, Big Injun, and a shallow Pennsylvanian reflection event were digitized for all lines from the high-resolution weight-drop surveys that were conducted this past winter in Granny Creek field. The isochron map of the Big Injun-to-shallow Pennsylvanian interval indicates that the fault block beneath the northern highly productive part of the field rose following deposition of the Big Injun sandstone. The isochron map of the Big Injun to Onondaga interval reveals the opposite: the northern part of the field subsided during the interval of time preceding deposition of the reservoir interval. Local thickened areas within the Big Injun to Onondaga isochron are interpreted to be detached structures. Some of the high producing areas in the northern part of the field correlate with these locally thickened areas. The isochron maps indicate that basement faults associated with the field were actively moving before and after deposition of the reservoir, and very probably, they moved to a slight degree during deposition of the reservoir interval itself. Interpreted detachment occurred late in the history of the basin during the Alleghanian orogeny.

PETROLOGY

Bar graphs were constructed showing relationships between wire log data and petrographic features determined from thin sections. Packing density, cement and intergranular porosity were plotted on triangular diagrams for several key wells. These graphical representations supported most of the preliminary conclusions on petrographic factors controlling porosity and permeability in the Big Injun Sandstone in the Granny Creek Field. Higher packing density in the lower part of the fluvial channel facies was partly due to original poor sorting and

compaction attending pressure solution in the illite-rich layers. Lack of grain coatings in this part of the channel facies led to quartz cementation further reducing porosity and permeability. Infiltration illite commonly coated grains in the upper part of the channel facies so that quartz cementation was impeded and good porosity remained.

The origin of chlorite coatings received particular attention because of their importance in restricting quartz cementation. In general, the mixing of saline and fresh waters in the mouth bar appears to be the most important factor in producing the well-formed chlorite coatings in the mouth bar facies. Fresh water essentially free of saline water in the lower fluvial channel constituted unfavorable conditions for chlorite formation hence quartz was free to grow with loss of porosity in this zone. In the upper fluvial channel facies, chlorite coated grains occurred in some layers. Apparently local incursions of the sea led to mixing of saline and fresh waters resulting in favorable conditions for chlorite formation. In addition to these general variations in the formation of chlorite that affected quartz cementation, there were some variations in the nature of the chlorite that caused variable distribution of quartz cement on a microscopic scale. In some cases quartz grains coated with rims of foreign material were deposited alongside clean grains. Good chlorite coats apparently formed on the grains with pre-existing rims so that quartz growth was minor on these grains compared to the clean grains. Partial replacement of chlorite coatings by siderite also resulted in poorly covered grains so that secondary quartz could grow at these points. Locally, compaction caused fracturing of coatings and exposed quartz that became favorable sites for quartz growth.

The distal mouth bar facies is characterized by relatively low permeability even though the porosity is fairly good. In some cases this is due to finer grain size, but in other cases it is related to small growths of siderite in the pores or unusually thick chlorite coatings.

The paragenetic sequence for the Big Injun Sandstone in the Granny Creek Field was refined. Illite, secondary feldspar, chlorite, and some calcite formed early. Secondary quartz grew at an intermediate state. Siderite and calcite with some dolomite developed late.

The petrographic features of the Big Injun Sandstone in the Rock Creek Field is similar to that shown in the Granny Creek Field except that most of the fluvial channel facies is not present. Several of the wells show a coarsening upward sand sequence. As in the case with the Granny Creek Field, illite-coated grains are more common near the top of the unit. Quartz cement occurs in small amounts and also is generally limited to the upper part of the sandstone.

The middle interval of the sandstone has well-coated chlorite grains and good porosity. Siderite is more common than in the Granny Creek Field and tends to be concentrated in the lower part of the sandstone where it reduces porosity

considerably. The paragenetic sequence in the sandstone in the Rock Creek Field is the same as in the Granny Creek Field.

RESERVOIR MODELING

During the reporting period, work continued in the determination of formation and fluid properties. The results from log and core analysis were utilized in the assignment of formation properties to new individual grids. Figures 2 and 3 show the location of wells and the orientation of the new grid system, respectively.

Fluid properties were compiled for the water flooding study area. Runs were conducted for three different five-spot water flooding patterns. The cumulative oil production predicted by the model were compared with field data. Figure 4 shows the cumulative oil production between 1926 and 1991 for wells 15-1439, 15-1447, and 15-1598 for the Granny Creek Field, in Clay and Roane Counties, West Virginia. The assigned formation and fluid properties were adjusted within the range of data to improve the predictions. Figure 5 shows the comparison of field data and model predictions for cumulative oil production at the left five spot pattern.

The code for the BOAST numerical model was modified to yield more output at each time step. The computer code was also changed to yield more output at each time step. The computer code was also changed to work with the newly upgraded Unix system.

During the previous quarter, efforts were focused on the continuation of work previously performed on studying the effects of major heterogeneities on oil recovery.

One of the main points that remained to be studied, was the effects that the presence of major heterogeneities might have on distribution of fluids in an oil reservoir. Fluid distribution in the reservoir can be mapped by pressure distribution. Since fluid flow is directly proportional to pressure gradient, higher pressure in part of the reservoir indicates presence of fluid in those parts. In a nutshell, understanding the effects of major heterogeneities on pressure distribution in a reservoir could guide engineers in designing more effective enhanced oil recovery processes. This is due to the fact that the knowledge of fluid present in a particular part of the reservoir is of the utmost importance for well placement during enhanced recovery processes.

During the past quarter, a well planned investigation was designed to study such effects. The results of this study is presented. Since it has already been established that the orientation of major heterogeneities with the system's streamlines are critical, and that significant affects are encountered only when these heterogeneities are oriented perpendicular and/or parallel to the streamlines, only these cases will be presented. The test was designed as follows; a 13 by 13 grid with one well at the center was used. The primary

production was carried on for 150 days. At this point the well is shut in and left for 50 days to reach equilibrium. Four injection wells are then drilled in four sides to simulate a five-spot water flooding pattern.

Figure 6 presents the pressure distribution in a system where no heterogeneity exist. Figures 7 through 10 show the effect of different major heterogeneities on pressure distribution. The oil production rates for the secondary phase of the recover are shown in Figures 11 and 12.

GEOSTATISTICS AND MODELING

The two main objectives for this quarter were:

- completion of the modeling of porosity, production, and facies distribution for Rock Creek,
- comparison of modeling results for Granny Creek and Rock Creek.

Examination of 3-D porosity models for the Big Injun reservoir in both the Granny Creek and Rock Creek fields confirmed the presence of three-dimensional, low porosity zones (noted previously as density or shale barriers) intersecting multiple wells. This strongly suggests a porosity/permeability component of reservoir heterogeneity at both the well-to-well and intra-field scale. Comparison of Granny Creek and Rock Creek porosity distribution indicates a distinct difference between the two fields. Examination of Figures 13a and 13b suggests that the most porous reservoir(> 17% log porosity)in Granny Creek is strongly compartmentalized into relatively small zones (100m to 1000m in cross sectional diameter), whereas relatively high porosity for Rock Creek occurs in larger (200m to 4000m in cross sectional diameter), more continuous zones. Perhaps more importantly, the average cross sectional diameter of the higher porosity zones in Granny Creek is ~400m, approximately 3.5 times the average well spacing for the field (120m). For Rock Creek, the average diameter of the porous zones is ~1500m, approximately 10 times the average wells spacing for the field (150m).

Since oil production appears to be from these zones (see Figures 13a and 13b), the implications are that: (1)it should be relatively more difficult to discover producible oil in Granny Creek than in Rock Creek, (2) total production from individual Granny Creek wells should be smaller than for wells in Rock Creek, (3) secondary recovery programs based on fluid injection should be more difficult to design and implement for Granny Creek than Rock Creek, and (4) the potential for undiscovered petroleum is higher in Granny Creek than Rock Creek. The first conclusion has been previously established by an analysis of drilling completions for the two fields. Based on accounts of water and gas injection projects for the two fields, the third conclusion seems to be corroborated. However, the presence of high water

saturation in Rock Creek is an additional complicating factor and the success of secondary recovery by these methods has been greater in Granny Creek than in Rock Creek. Analysis of individual well performance for the two fields is currently underway to test the second conclusion.

Figure 14 is a map of Granny Creek showing the geographic distribution of low porosity zones within the Big Injun. Superimposed on the map are the traces of inferred normal and strike-slip basement faults taken from the work of Zheng, et al. (1993) and based on independent analysis of seismic and structural data. The correspondence between the locations of the inferred basement faults and low porosity zones in Granny Creek is remarkable. Low porosity zones can be seen to align with fault traces. Multiple low porosity zones are seen to be concentrated in areas inferred to represent down-dropped blocks or intersections of faults. The implications are that these inferred faults are "real" features of a through-going nature that deformed the Big Injun reservoir and help localize cementation. Figure 15 is a map of Granny Creek showing an example of kriged cumulative production information. Once again, traces of inferred basement faults have been superimposed on the map. The correspondence between several of the fault traces and the margins of the higher production trends for the field are noteworthy. It is speculated that similar correspondence between basement structure, cementation, and oil production may be present in Rock Creek, although to a lesser extent since Rock Creek appears to be less strongly compartmentalized than Granny Creek.

REFERENCES

Zheng, L., Shumaker, R., and Wilson, T., 1993, A seismic interpretation of the structural development of the Granny Creek oil field, in, 24th Annual Appalachian Petroleum Geology Symposium - Program and Abstracts, p. 125-126, abst.

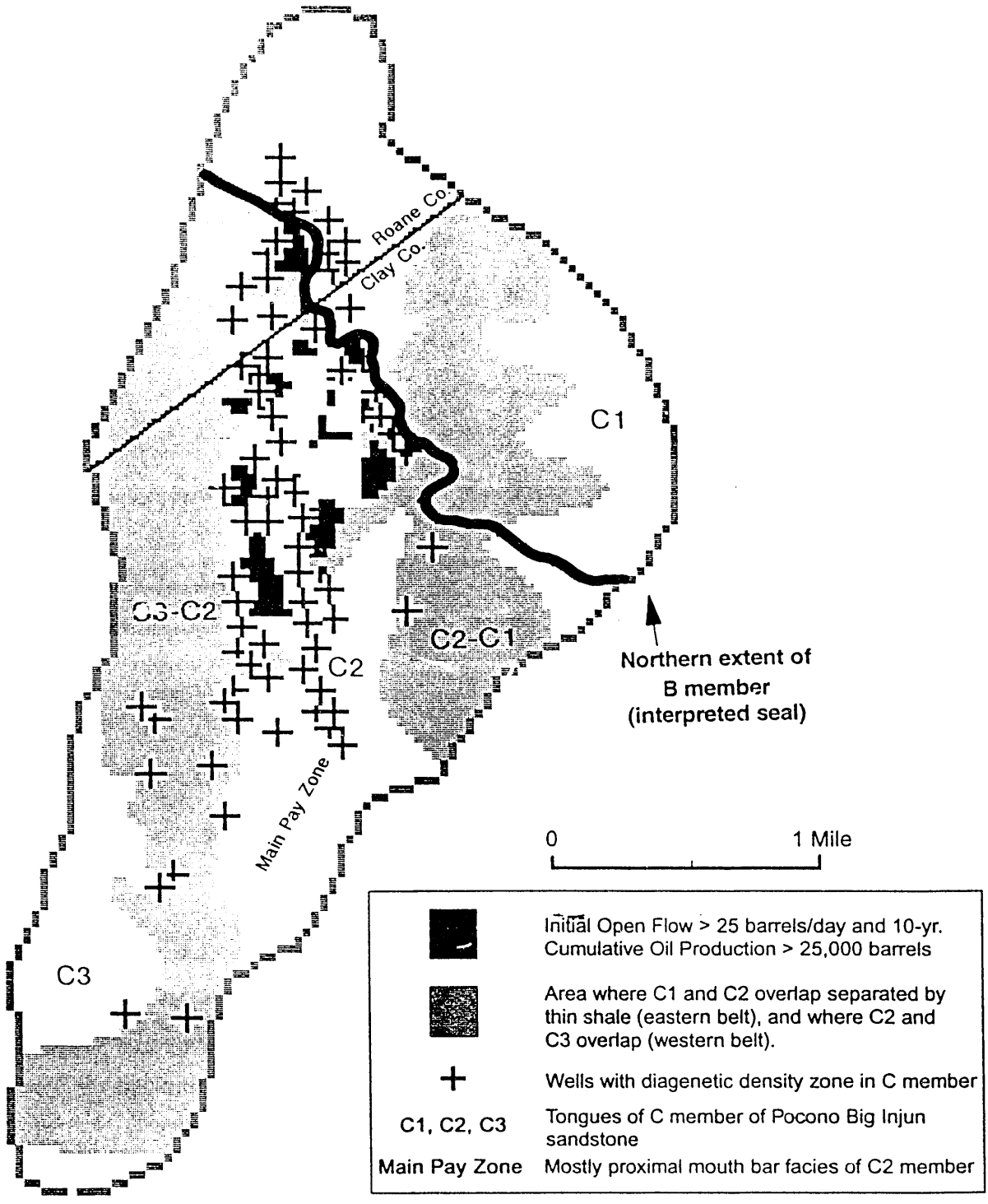


Figure 1 Four stratigraphic conditions that influence primary oil production are:

1. Presence of B zone seal (eroded by Pre-Greenbrier Unconformity)
2. North-south trend of pay zone, marine proximal mouth bar facies of C2
3. Depositional shale barrier
4. Diagenetic cementation/mineralization barrier

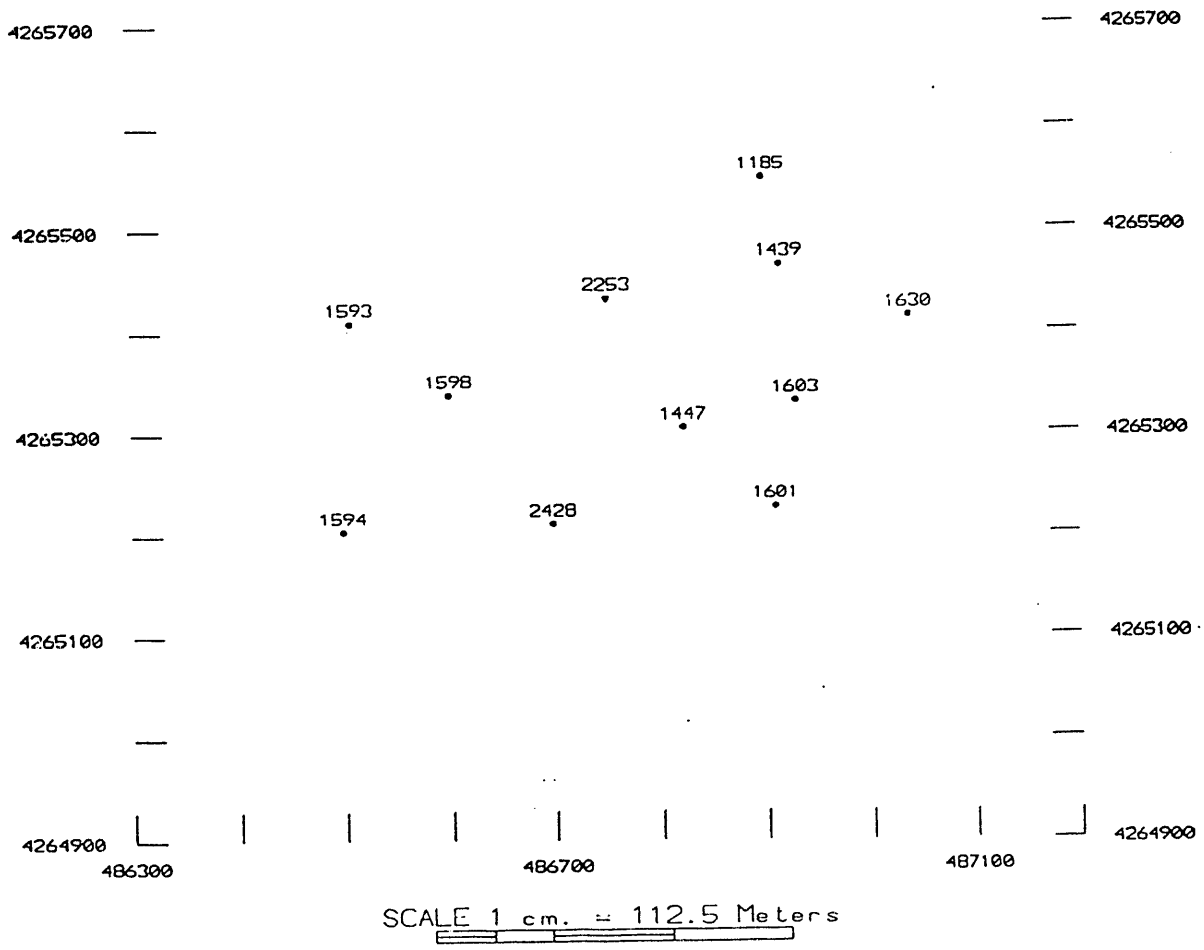


Figure 2. Location of Wells for the 5-Spot Water Flooding Model Study in the Granny Creek Field.

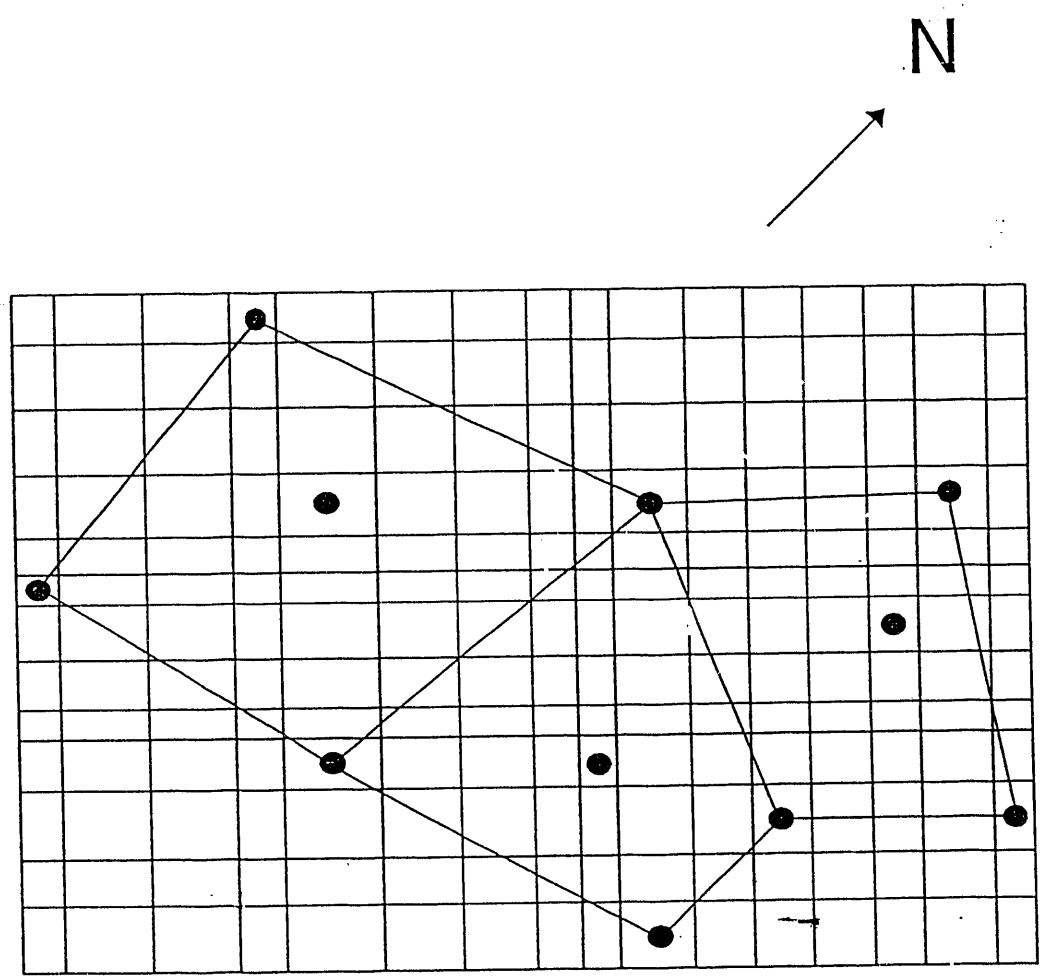


Figure 3. Orientation of Wells in the 5-Spot Water Flooding Model Study in the Granny Creek Field.

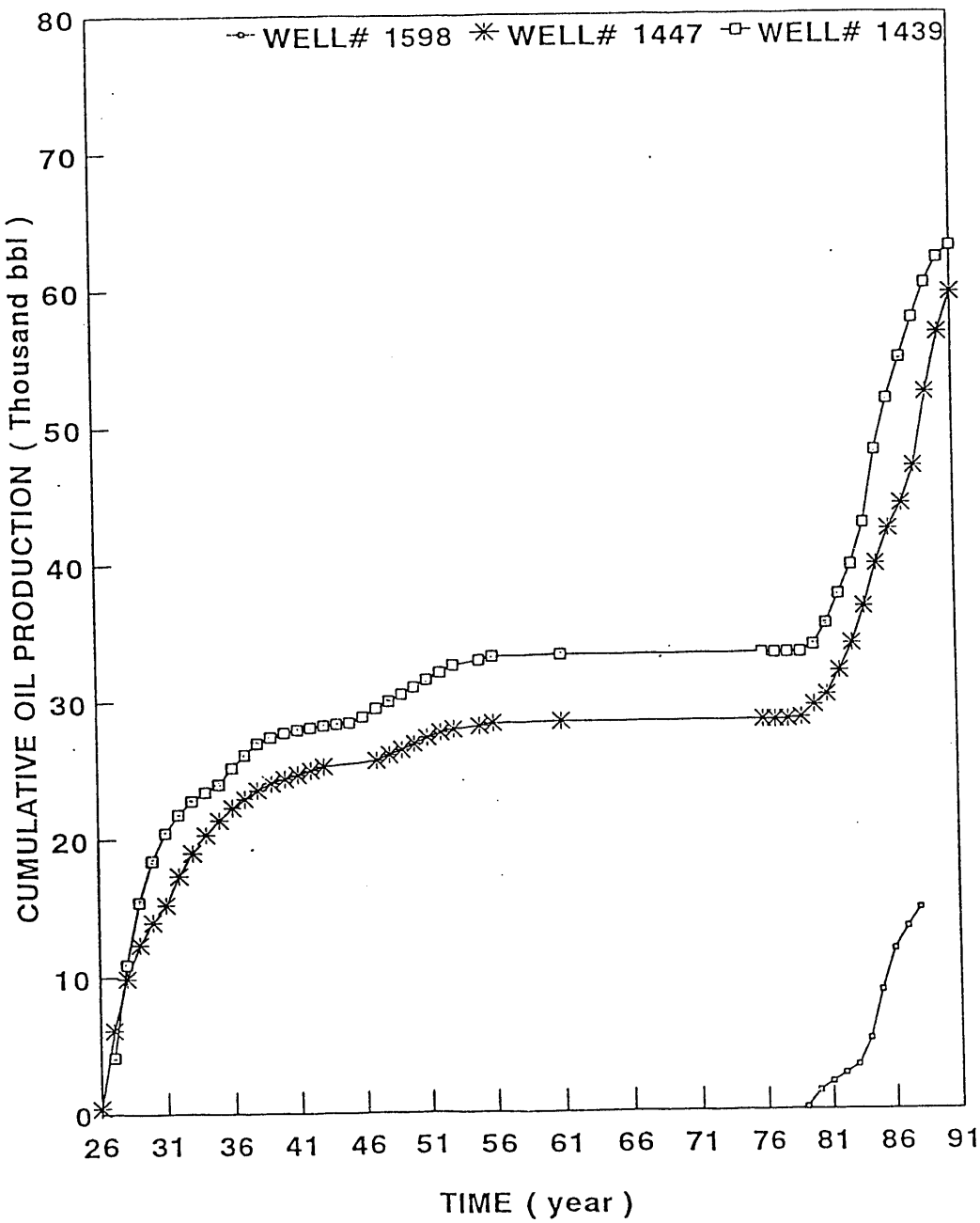


Figure 4. Cumulative Oil Production versus Time Between 1926 and 1991 for Well Nos. 1598,1447, and 1439 in the Granny Creek Field.

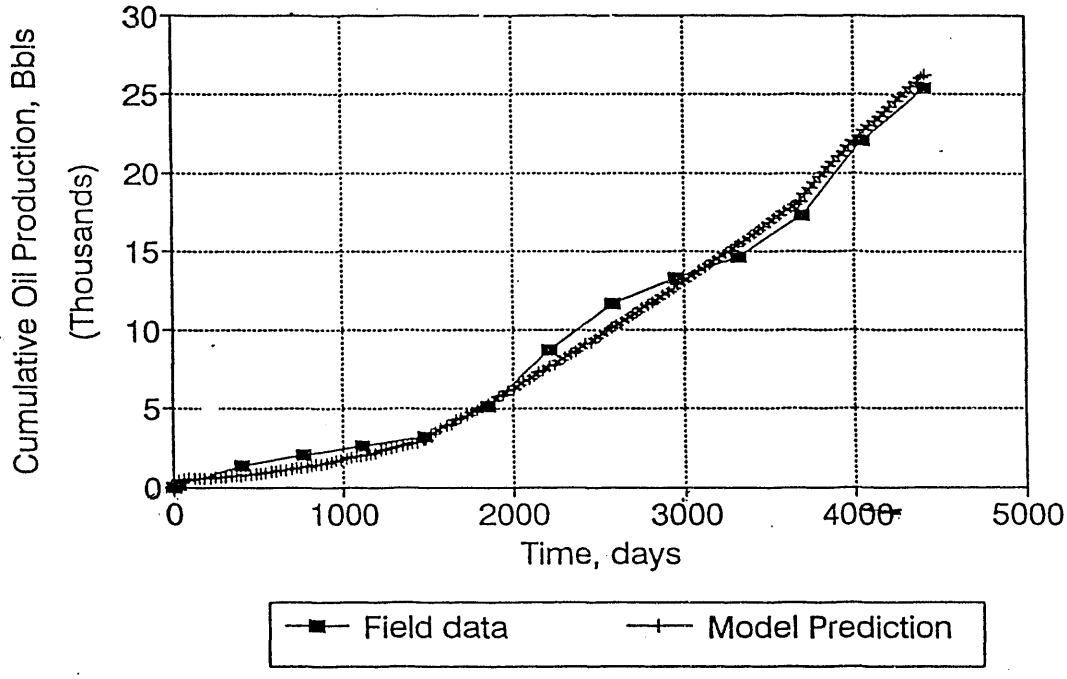


Figure 5. Comparison of Predicted and Actual Cumulative Oil Production for the 5-Spot Water Flooding Model Study in the Granny Creek Field.

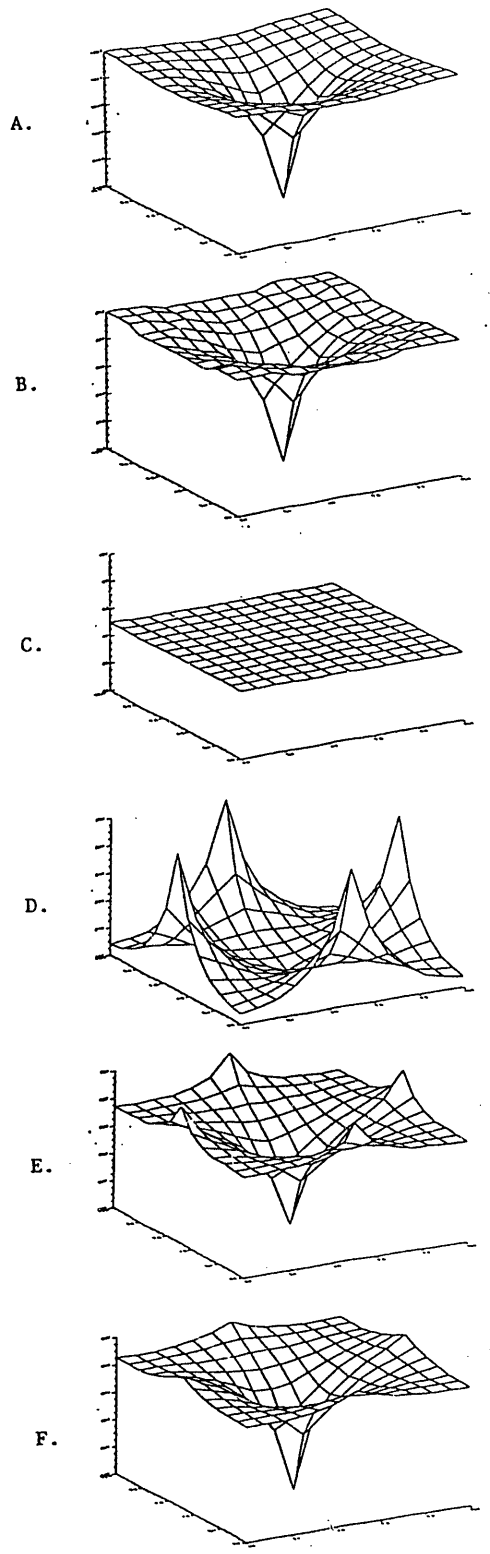


Figure 6. Pressure Distribution for Primary (a,b), Shut-in (c), and Secondary Recovery (d,e, and f) for a Reservoir with no Major Heterogeneities.

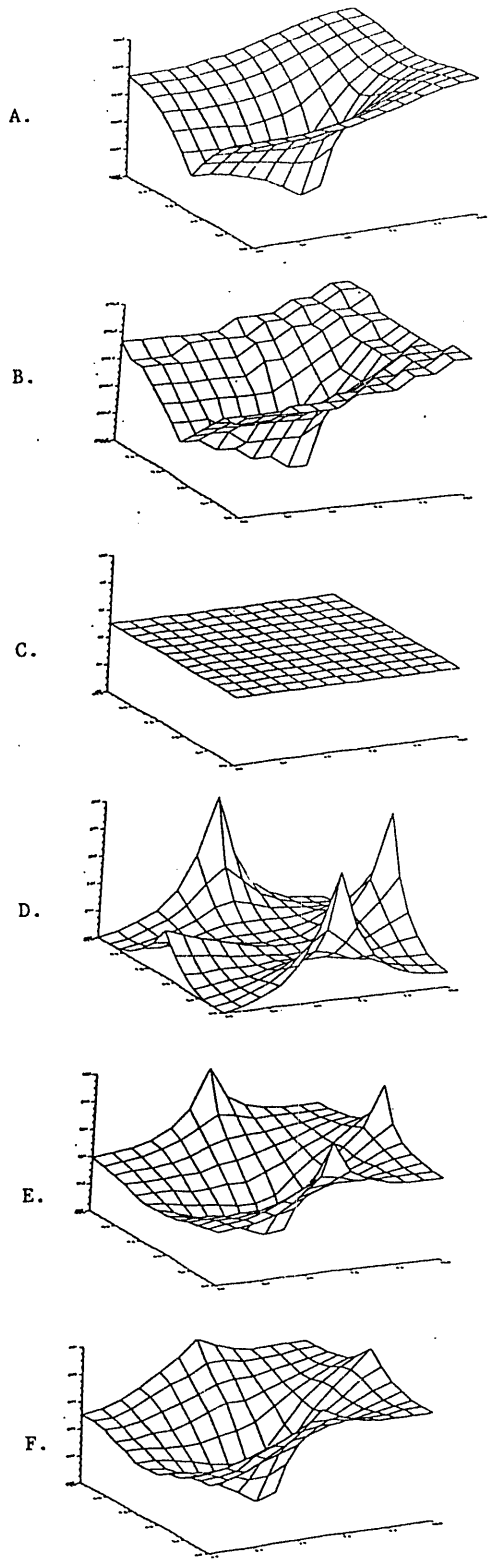


Figure 7. Pressure Distribution for Primary (a,b), Shut-in (c), and Secondary Recovery (d,e, and f) for a Reservoir with Parallel Channels.

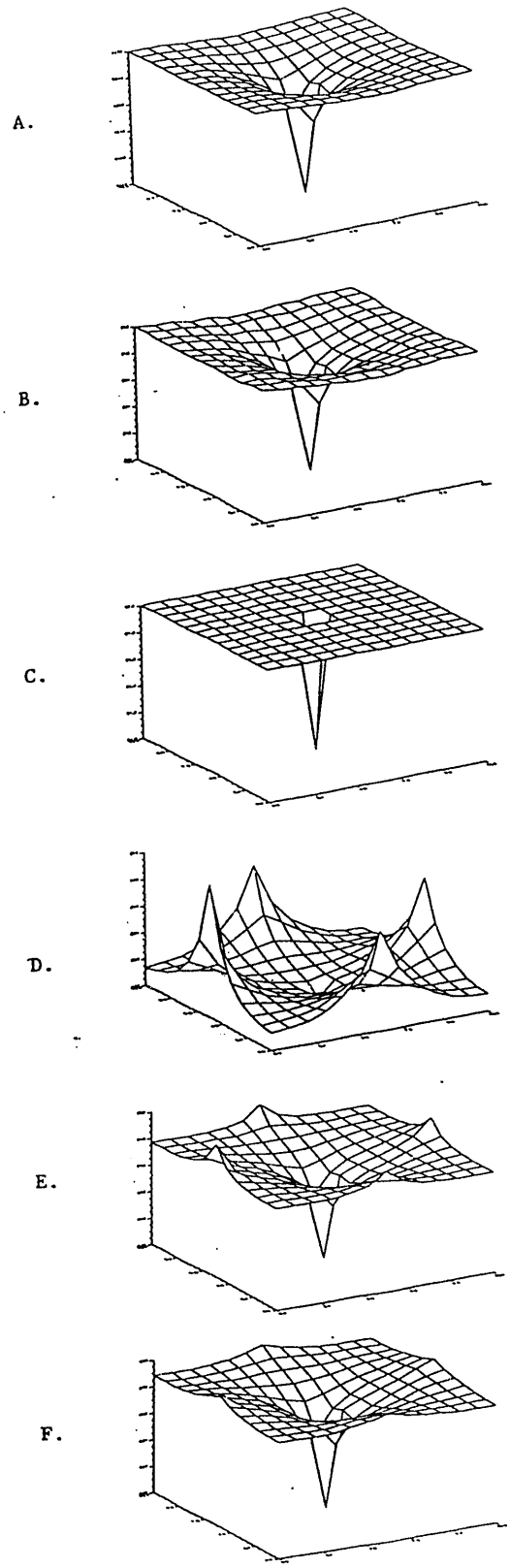


Figure 8. Pressure Distribution for Primary (a,b), Shut-in (c), and Secondary Recovery (d,e, and f) for a Reservoir with Parallel Barriers.

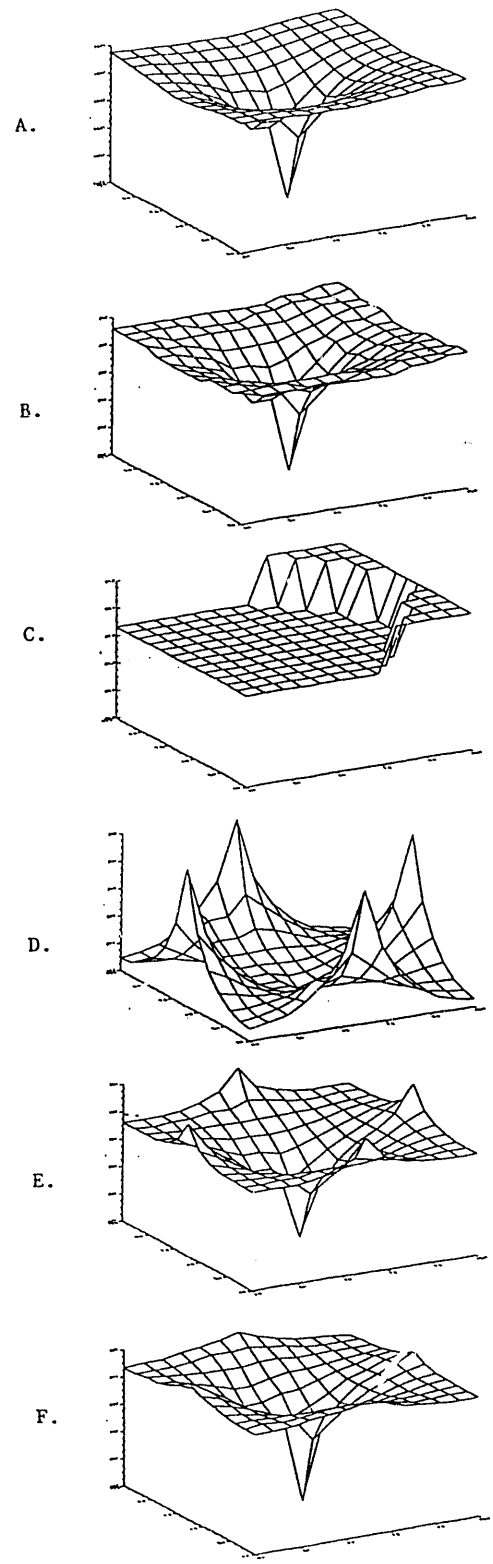


Figure 9. Pressure Distribution for Primary (a,b), Shut-in (c), and Secondary Recovery (d,e, and f) for a Reservoir with Orthogonal Channels.

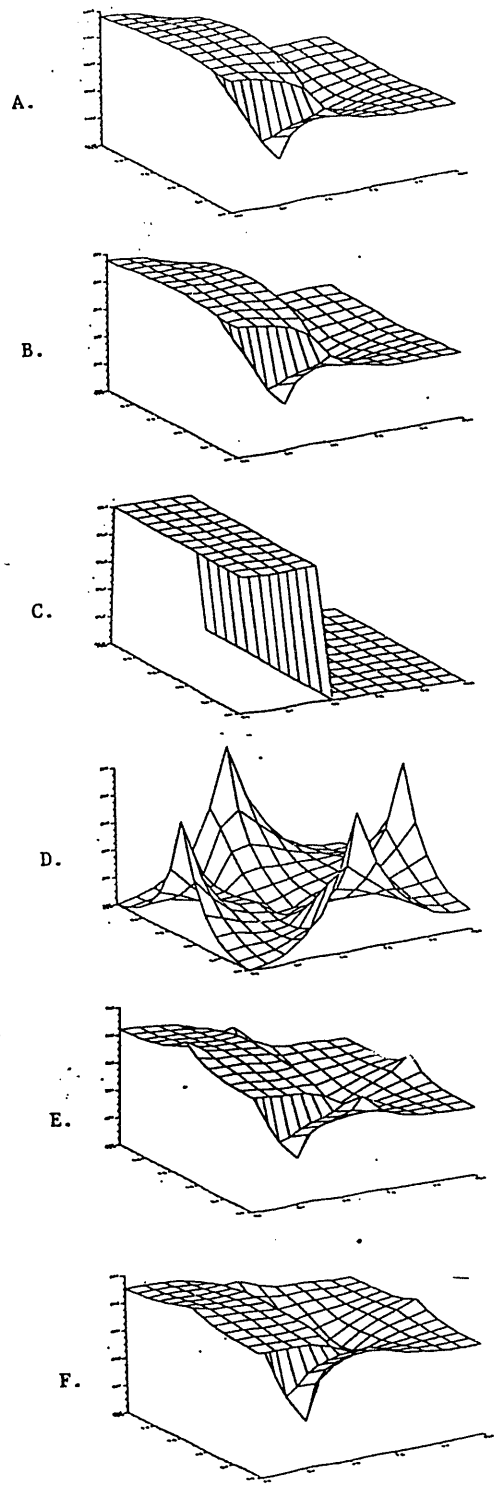


Figure 10. Pressure Distribution for Primary (a,b), Shut-in (c), and Secondary Recovery (d,e, and f) for a Reservoir with Orthogonal barriers.

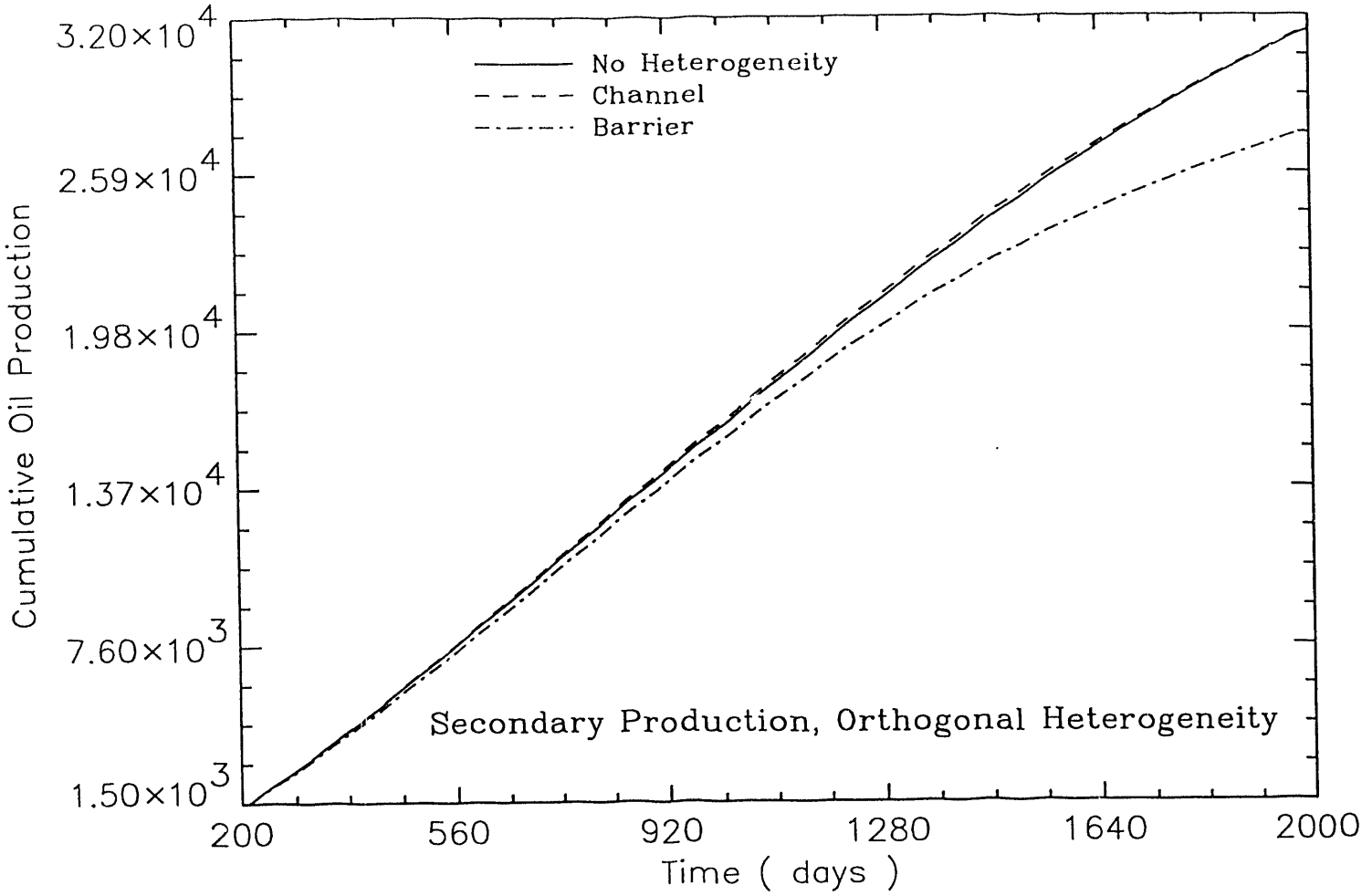


Figure 11. Cumulative Oil Production for Reservoirs with Orthogonal Heterogeneities.

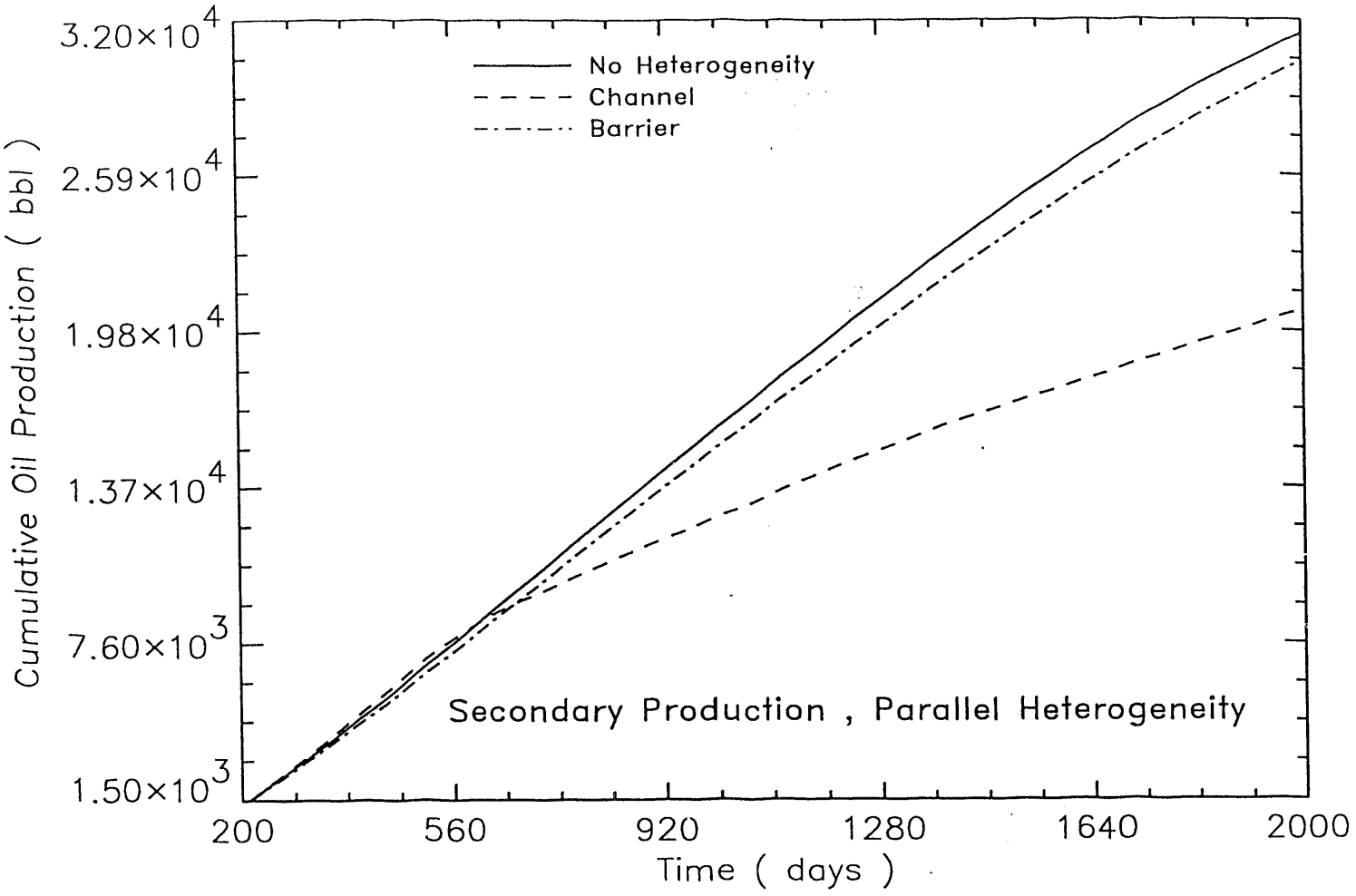
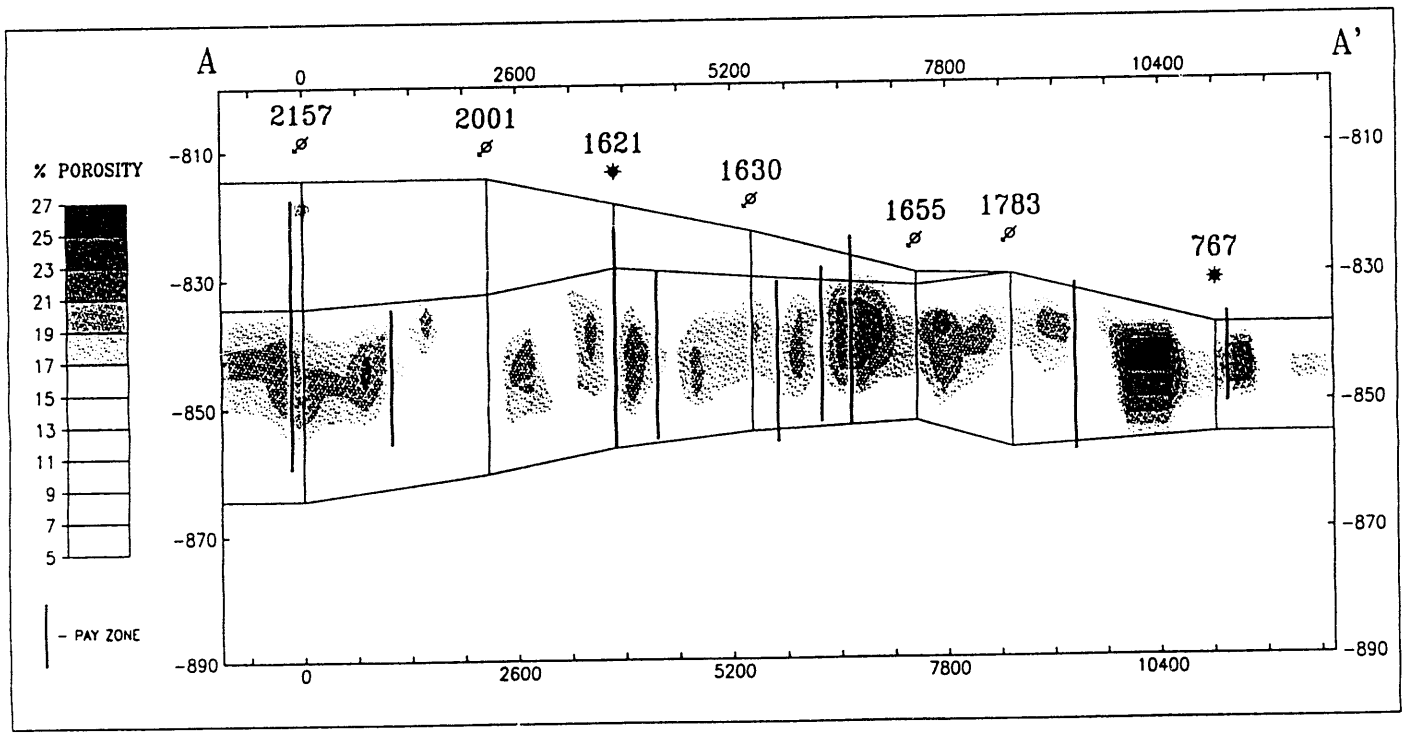


Figure 12. Cumulative Oil Production for Reservoirs with Parallel Heterogeneities.

FIGURE 13a. Porosity cross section A - A' for Granny Creek. Color shaded porosity intervals below 17% have been intentionally left blank to illustrate the distribution and approximate size (cross sectional diameter) of zones of relatively high and low reservoir porosity. Contour interval is 2% porosity; vertical exaggeration is 75:1; reference coordinates for the cross section are in feet.



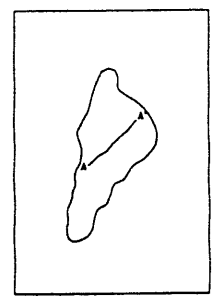
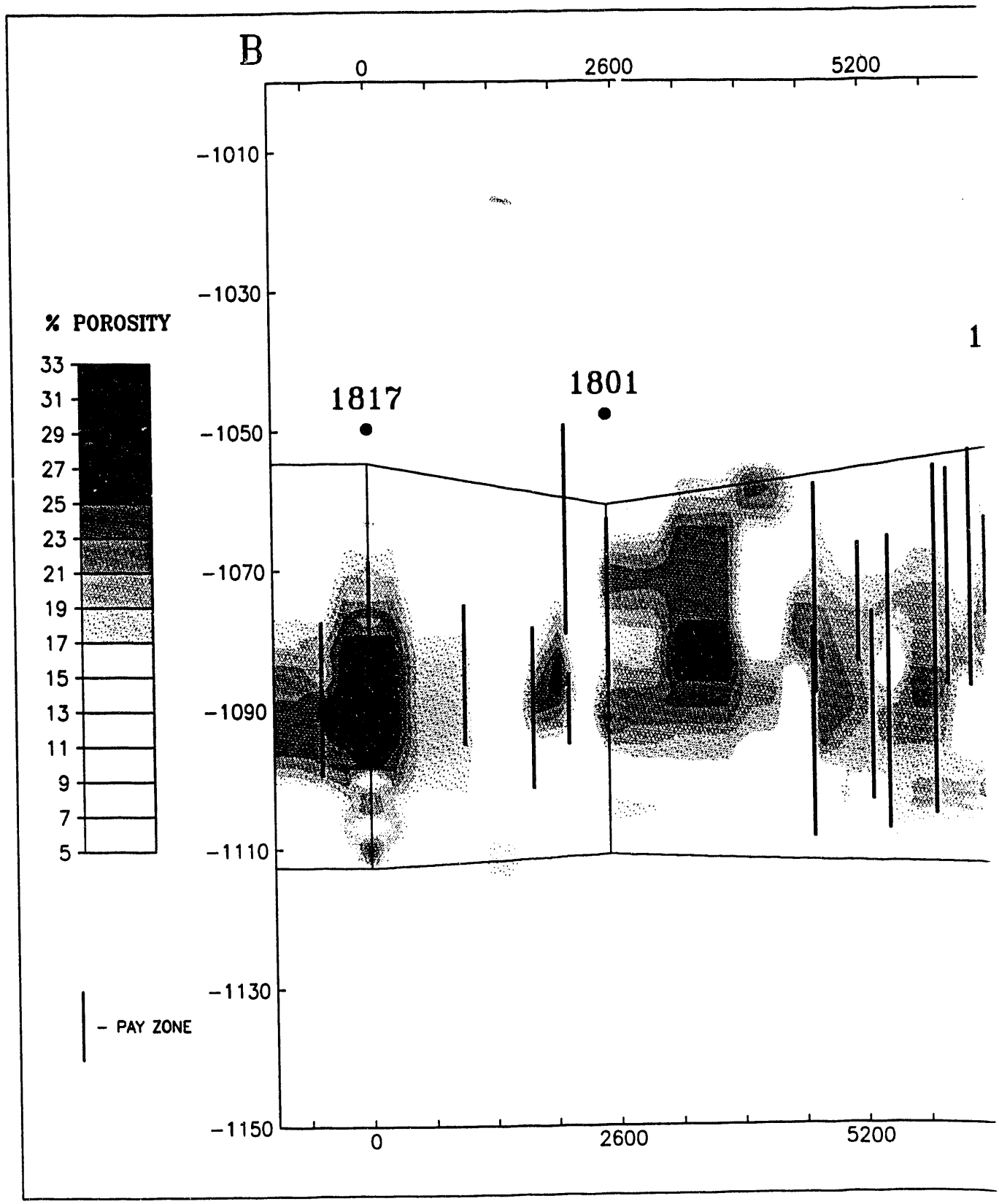


FIGURE 13b. Porosity cross section B - B′ for Rock Creek. Color shaded intervals below 17% have been intentionally left blank to illustrate the approximate size (cross sectional diameter) of zones of relatively high ar porosity. Contour interval is 2% porosity; vertical exaggeration is 75:1, coordinates for the cross section are in feet.



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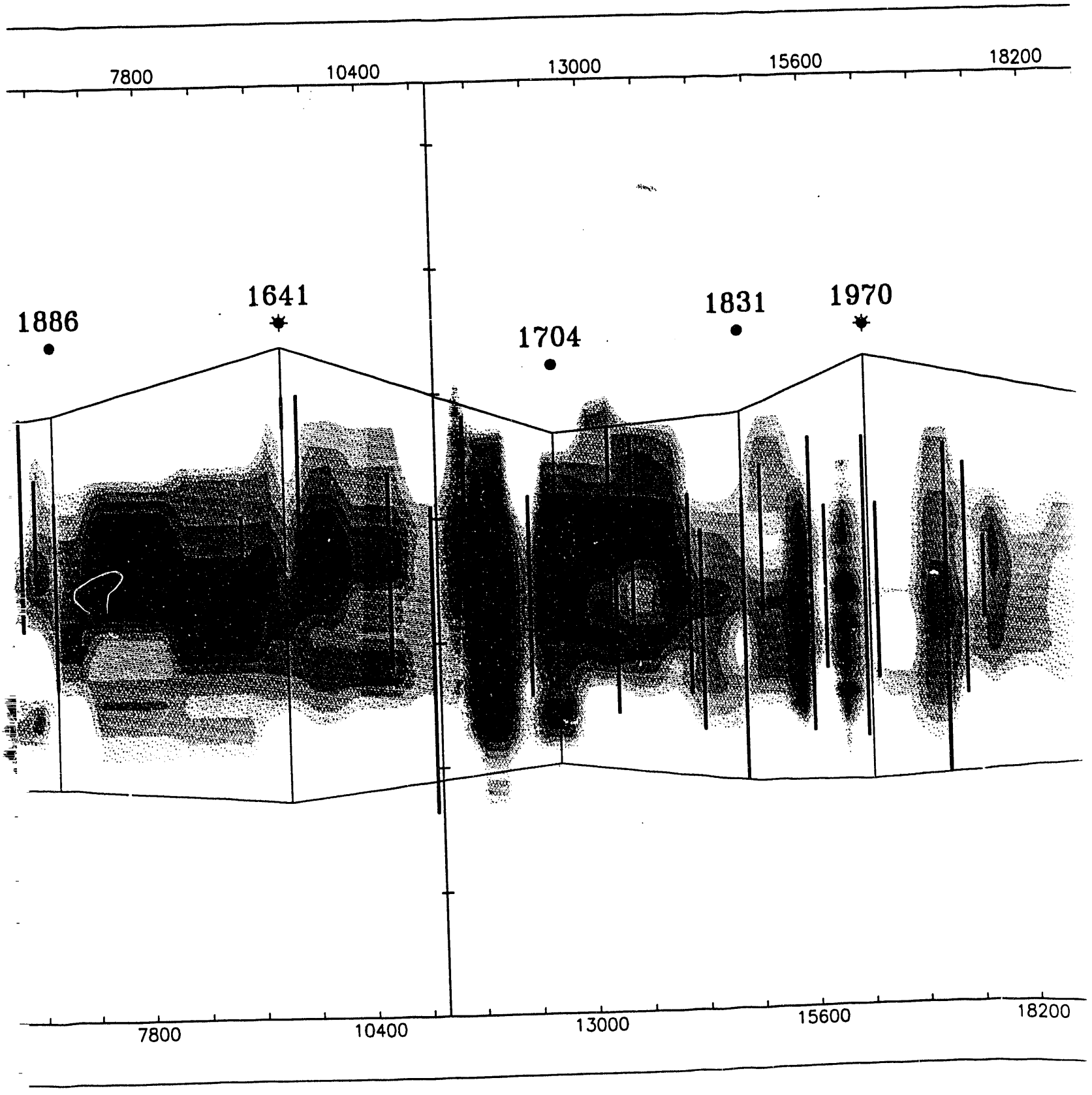

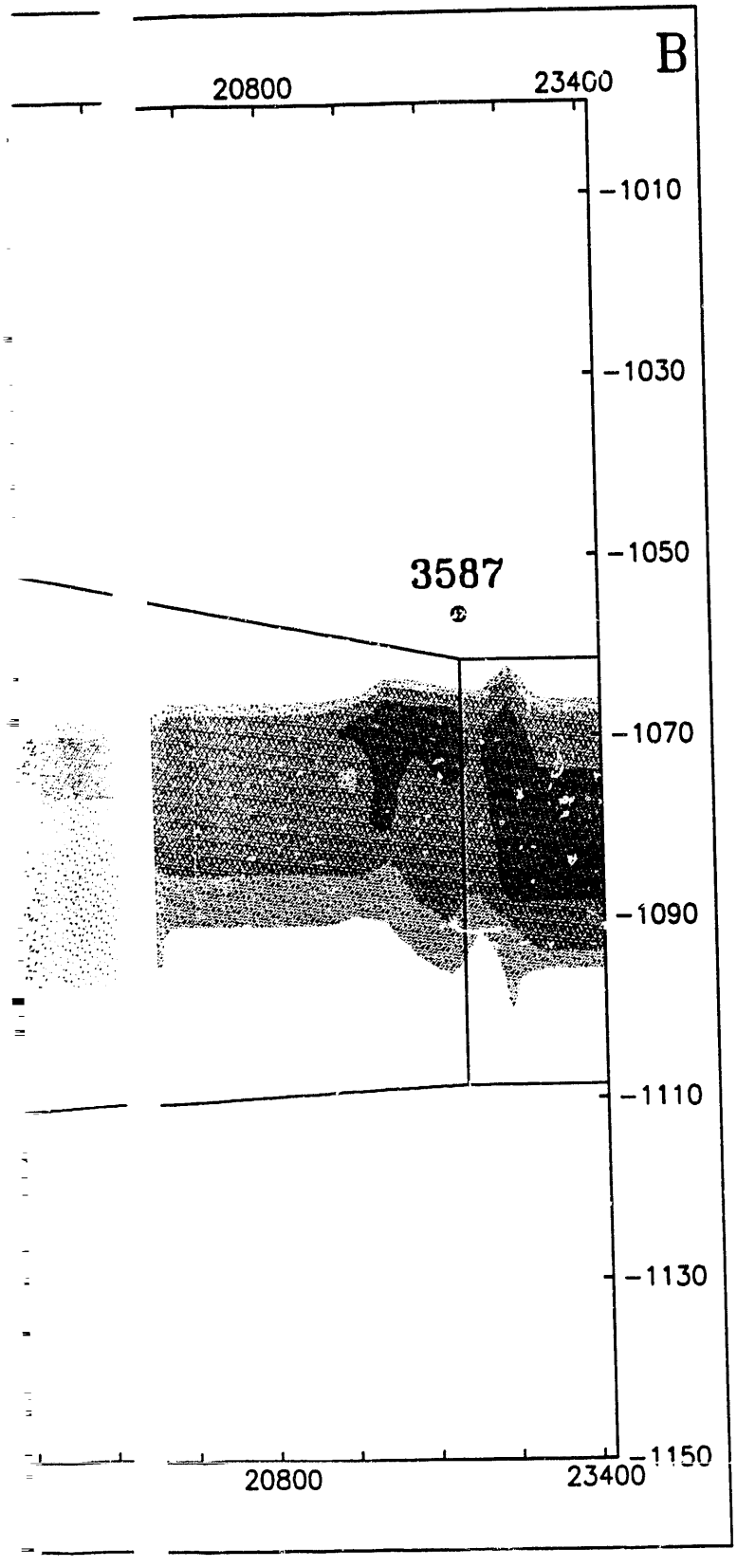
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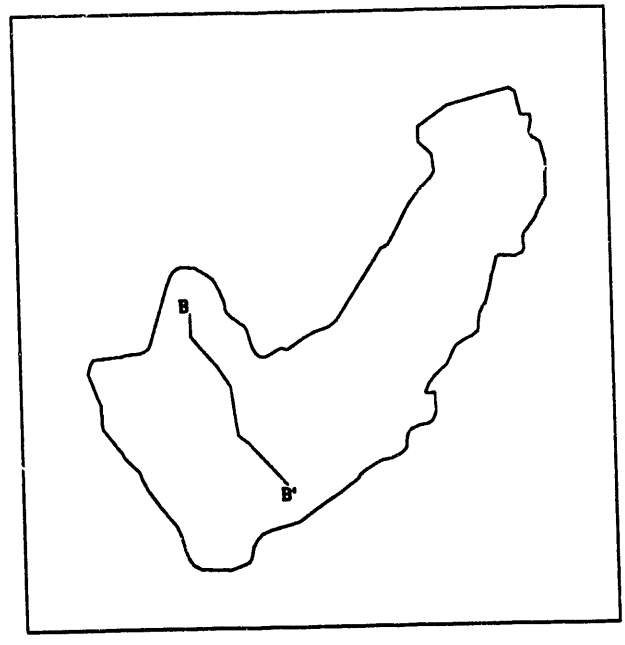

B
B'

FIGURE 14. Map of Granny Creek showing the location of low porosity zones within the Big Injun reservoir. The margin (zero thickness contour) of the low porosity zones are shown in as grey lines. Traces of inferred normal and strike-slip basement faults have been superimposed as black lines.

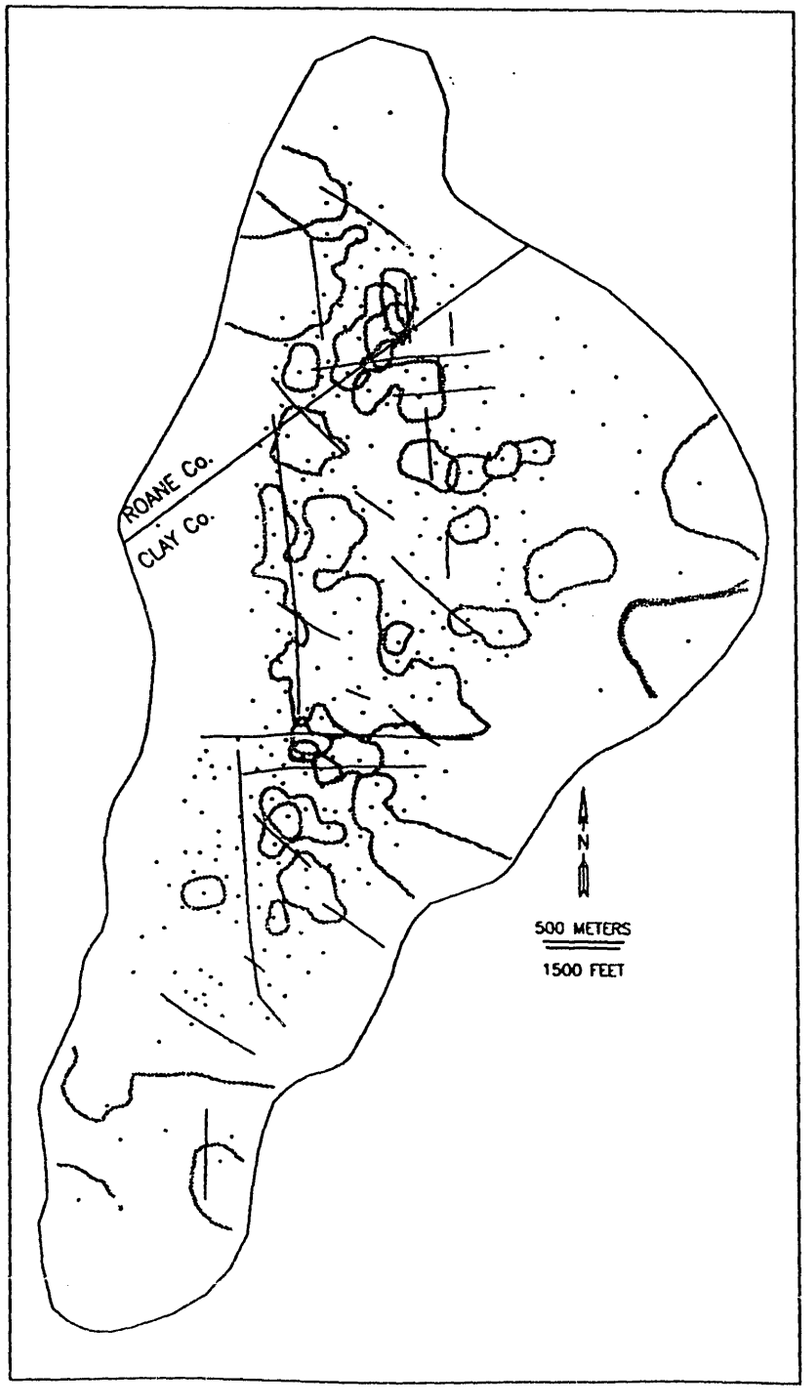
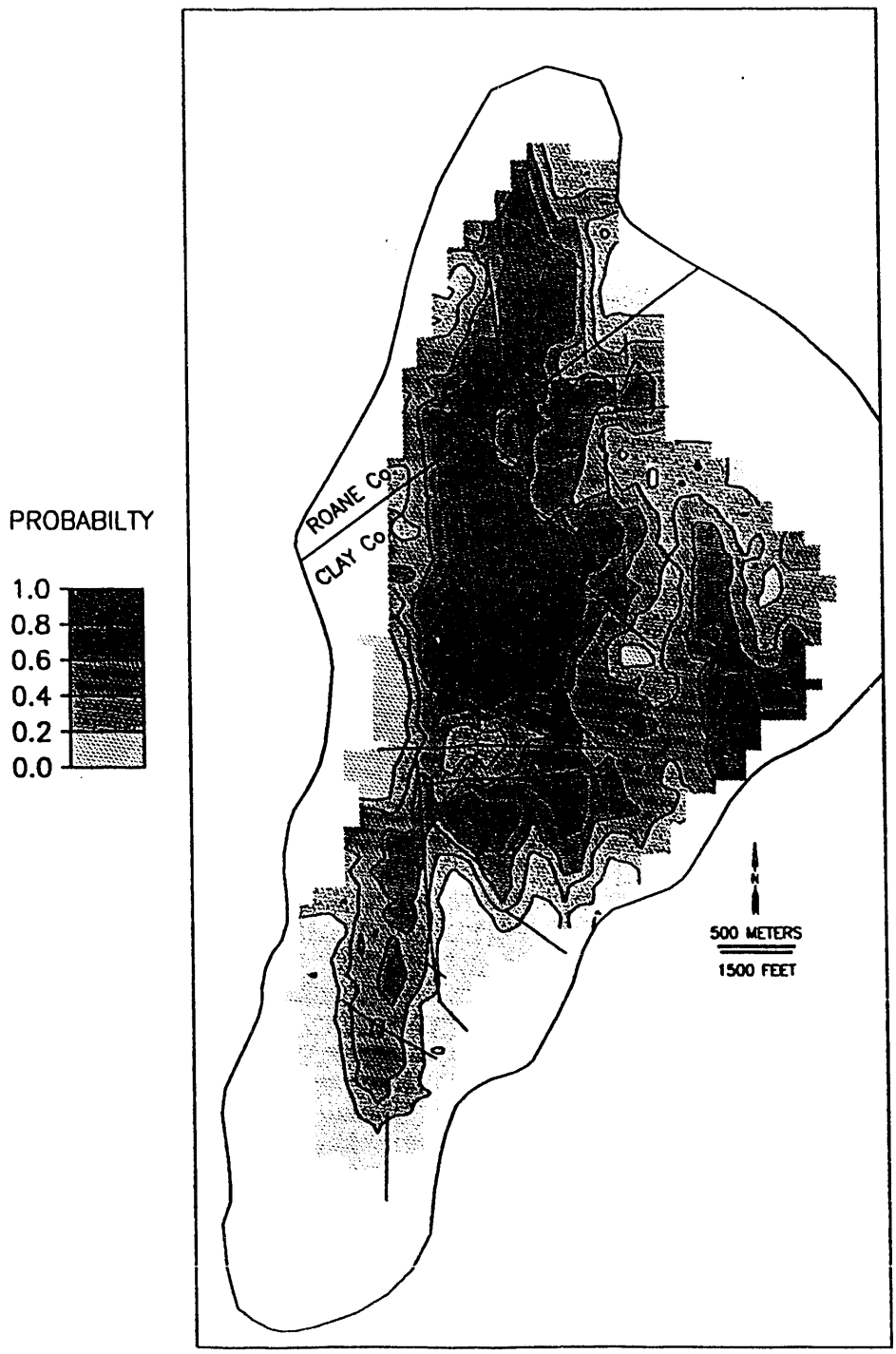


FIGURE 15. Map of Granny Creek showing probability of cumulative production (first ten years) exceeding the median value (12,335 bbls) for the field. Traces of inferred normal and strike-slip basement faults have been superimposed as black lines.



APPENDIX A
Big Injun Synclinal Oil Explained

BIG INJUN SYNCLINAL OIL EXPLAINED

R. C. Shumaker, A. C. Donaldson, T. H. Wilson, Li Zheng, and Xiandong Zou

One of the unresolved questions related to Appalachian Basin oil fields is the occurrence of synclinal oil, and perhaps more importantly, the absence of bottom-edge water in certain reservoirs of southern West Virginia (Davis and Stephenson, 1929). Such is the case in the Big Injun reservoir, the subject of our study. It is necessary to recall the geologic history of the Appalachian basin in the study area to understand the likely cause for such unusual trapping conditions.

Basement Structure

Most basement structures in the Appalachian foreland formed as the result of two intense and areally extensive deformations. The older of the two, called the Grenville orogeny, formed the continental crust, or basement, (Beardsley and Cable, 1983) at approximately one billion years ago. The second deformation, Interior rifting, occurred approximately 560 million years ago during Early and Middle Cambrian time. Slow, broad subsidence of the crust prevailed for the rest of the Paleozoic. From Middle Ordovician (450 my) through Permian time (215 my) this subsidence was largely in response to tectonic and sedimentary loading along the Appalachian orogenic margin of the North American plate. The distribution of Paleozoic lithofacies and thicknesses (Donaldson and Shumaker, 1981; Shumaker, 1986) in the Appalachian basin suggests that this subsidence was not uniform in time and space, but that the basement subsided as several large blocks which moved somewhat independently of one another (Figure 1). Seismic investigations show that block boundaries are basement faults or flexures. The faults that were active during subsidence appear not to have been initiated by the subsidence, but were reactivated faults formed by the previous, and regionally intense, Interior or Grenville deformations.

The boundaries of these subsiding blocks are reflected in the sedimentary record of the basin as lines or trends of stacked changes in rock thickness and facies that commonly have been called "arches" or "hinge lines". Such is the case along the Cambridge arch and its faulted southward extension into West Virginia under the Burning Springs anticline of the study area (Figures 1 and 2). Other block boundaries (hinge lines) occur above large basement faults such as that found along the eastern edge of the Rome trough (Figure 1).

Even though such basement structures have affected the distribution of Paleozoic sediments, it is the affect of the block boundary between the Tri-State and Ohio-West Virginia blocks on the distribution of Big Injun sediments (Figure 3) that is of interest here. Note the relationship, that is, the location

and trend of the basement fault under the Burning Springs anticline (Figures 1 and 2) with the trend and position of the Pocono/Price and "Maccrady" Big Injuns (Figures 4 and 5).

Another basement structure, the West Virginia dome (Figure 1), also called the Pocono dome or the Beverly uplift, is also important in the sedimentary and structural development and the distribution of the Big Injun sands. That the dome was high-standing during the mid-Mississippian is indicated by pre-Greenbrier erosion of sediments as old as the Upper Devonian Hampshire (Catskill) red beds near the center of the dome east of the study area. That it was a structure, at least a west-plunging nose, is indicated by low-angle dip of subcropping (pre-Greenbrier) units away from the dome on its north, west, and south flanks (Figures 1 and 3). The origin of the dome is uncertain, but it is presumed to have been a basement structure that grew during Mississippian time to influence the extent and depth of erosion that occurred prior to deposition of carbonates and sands of the Greenbrier Group (Figure 3). The eastern extent of Big Injun reservoirs (Figures 4 and 5), and thus the hydrocarbon production associated with them, are limited by erosion that occurred during this time interval.

Detached Structure

The study area is also located at the outer margin of detached deformation in the Appalachian foreland (Figure 2). These structures were formed by the Alleghany Orogeny of Permian age, and as such, they are considered not to have affected the deposition of Paleozoic sediments in the study area. A number of authors have proposed early (mid-Paleozoic) growth of certain detached structures in the Appalachian foreland, but a strong interrelationship between the position and trend of basement structure and overlying detached structure in the outer foreland (Shumaker, 1986) suggests that such reported growth relates to underlying basement structure rather than pre-Alleghanian growth of detached structures.

Several horizons were areally extensive zones of detachment within the Appalachian foreland, including the Cambrian Rome Formation, the Ordovician Martinsburg Formation, Silurian salt beds, Devonian shales, the Mississippian Mauch Chunk Formation, and Pennsylvanian coals. The Devonian shales appear to be the major detachment horizon in the study area, although the Silurian salt is important at its northern margin.

One need only to look at the difference in the structural configuration between the Pittsburgh coal (Figure 6) and the Greenbrier Group (Figure 7), that lies above the Big Injun reservoir (Figure 3), to recognize the presence of structural disharmony in the Granny Creek-Rock Creek area. This contrast is greatest at the southeastern margin of these regional maps (Figures 6 and 7). The contrast indicates the presence of either a major or several minor detachment horizons in sediments between the Pittsburgh coal and the Greenbrier Limestone.

Our research indicates that detached structures of various scales occur throughout the Granny Creek-Rock Creek area (Donaldson, et al., 1992) and that detached deformation is more intense on the eastern (hinterland) side of the area.

Production

Big Injun oil fields are found in the synclines and on the flanks of anticlines of the region (Figure 7), and perhaps more importantly, the report noted the absence of bottom-edge water in the eastern Big Injun fields, such as at Granny Creek, and its presence in the western fields, such as at Rock Creek. All of the Big Injun fields within the study area occur at the northern end and down-dip from the crest of the basement-cored Warfield and Queen Shoals-Minnora anticlinal trend (Figure 7). However, small, low-relief folds in which oil occurs may, in part, be detached.

Keys to understanding the areal distribution of synclinal oil and the absence of bottom-edge water are the following; (1) recognition of the timing of hydrocarbon generation in this part of the basin, and (2), identification of structures present at the time of oil migration.

The likely source rocks for Big Injun oil, the underlying Middle and Upper Devonian and Lower Mississippian shales, entered the oil window during the Pennsylvanian before the Alleghany orogeny that formed the detached structures of the foreland. It should be recalled that certain basement structures grew throughout the Paleozoic. Thus any migration of hydrocarbons during the late Pennsylvanian must have been into basement structures; in the case of the Granny Creek and Rock Creek fields the adjacent basement anticline was the ancestral Warfield-Minnora anticline. Secondary (re)migration may have occurred during the Alleghany Permian orogeny into detached structures formed by that terminal orogenic event.

As post-Paleozoic erosion has removed the sedimentary overburden, gas has come out of solution and the cap has expanded forcing oil and edge water further down-dip and down-plunge north and westward, deeper into the basin. Some oil in local closed synclines, such as at Blue Creek (Figure 7), was by-passed as the gas cap developed and expanded. Any water that may have originally been present in the eastern fields was driven down-plunge, northward along the unconformity, or possibly laterally north and eastward through the unconformity into adjacent and overlying units such as the Greenbrier limestone.

Thus the eastern fields that include Rouzer, Granny Creek and Tariff are trapped in structural lows against the unconformity above the structural level of the oil-water contact, whereas the western fields have bottom-edge water, which at Rock Creek in the "Maccrady" Big Injun sandstone (Figures 3 and 4) lies at between -1140 and -1170 feet. Both the "Maccrady" (Figure 4) and Pocono Big Injun sands (Figure 5) reach these subsea depths only in the northern and western parts of the study area, and thus the western fields, like Rock Creek and Tippit, are the

only fields in the study area that have water legs.

The gas/oil contacts are nearly at the same elevation in the Big Injun fields except in the Blue Creek-Falling Rock area (Figure 7). These fields are located in and around a closed basement low on the western flank of the Warfield anticline. Oil in this elevated position may have been trapped here on the flank of the Warfield anticline as a remnant of the oil leg when it was much more extensive in the early history of the field. That is, oil in the adjacent structural highs was forced down-dip to the west by gas as the cap expanded. It seems likely that the slight differences in elevation among the other fields may be caused by any one of several possible reasons including: natural variation in reservoir pressure across such a large area; variations in the distribution of porosity in the reservoir sands of the Pocono and "Maccrady" Big Injuns; and late-paleozoic elevation of synclines along the eastern margin of the study area by detached Alleghanian deformation.

Arriving at this interpretation and a possible answer to the long-standing question concerning the absence of water in certain Appalachian oil fields (Davis and Stephenson, 1929) points to the importance of integrating regional analysis with local field studies. It is anticipated that other reservoirs in the Appalachian basin that are noted for their absence of bottom-edge water may be similarly explained by geologic studies that integrate detailed field studies with comprehensive regional analysis.

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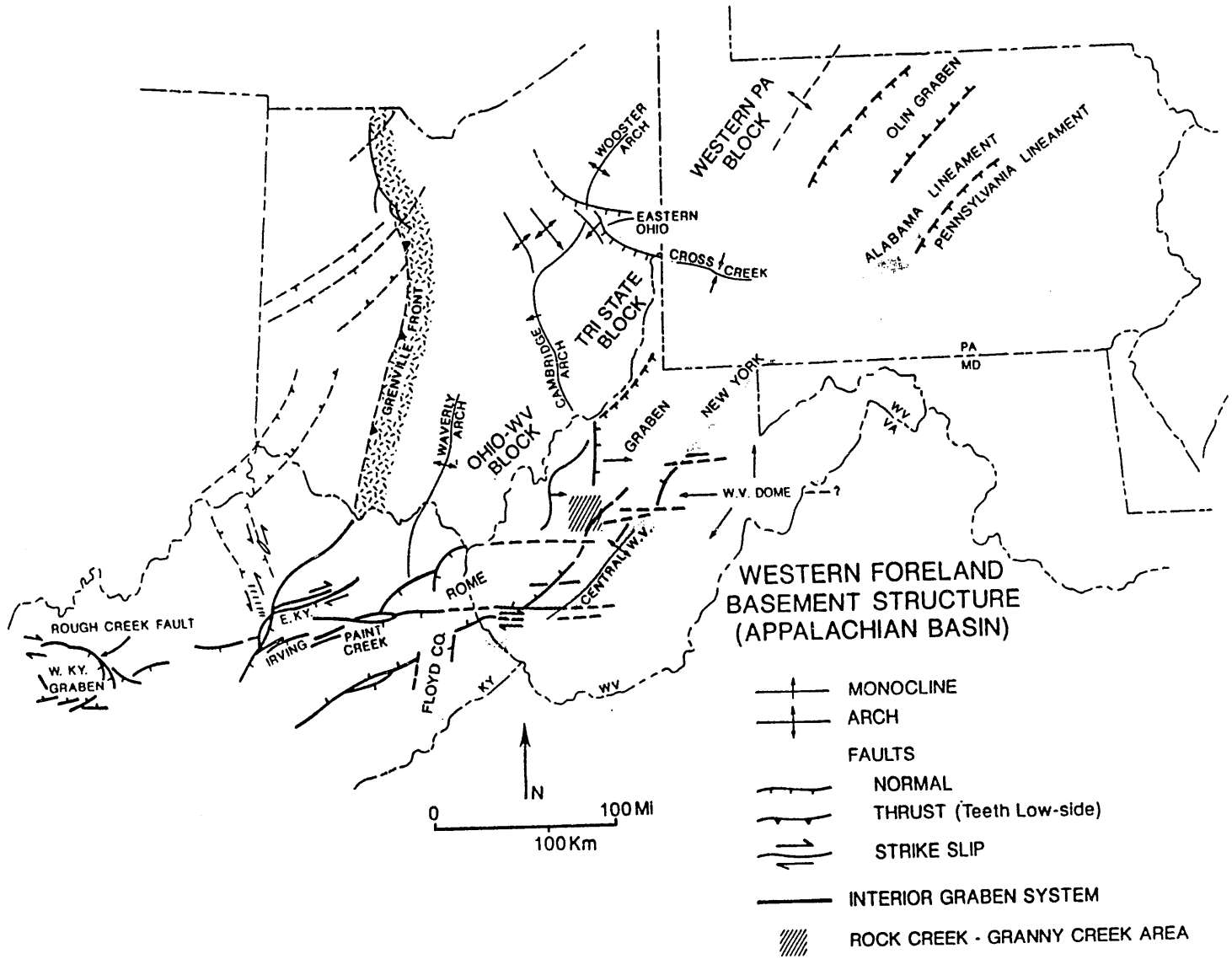

Figure 1. Regional tectonic map of basement structure.

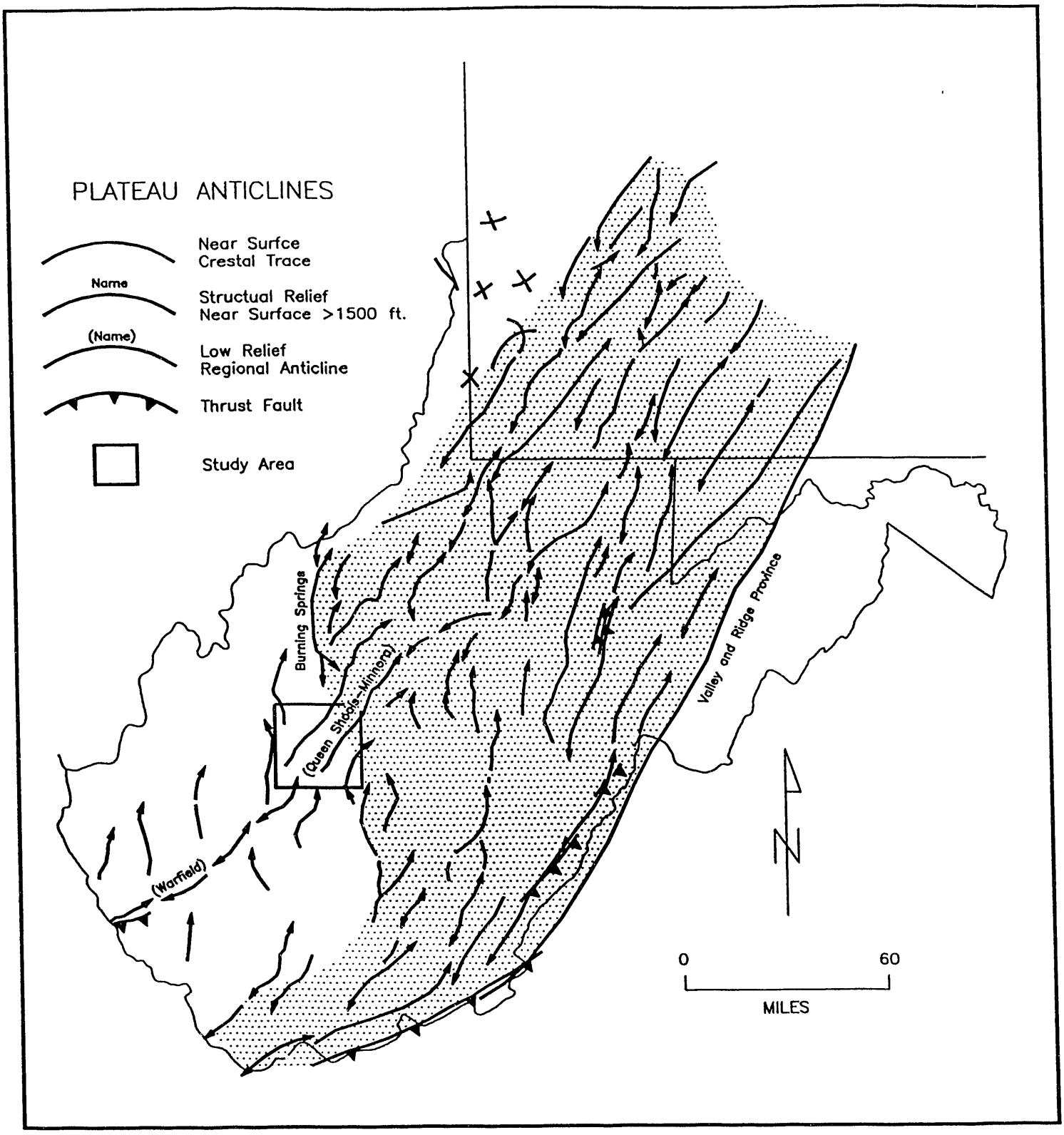

Figure 2. Tectonic map of surface structure in West Virginia. Most structures in stippled area are detached.

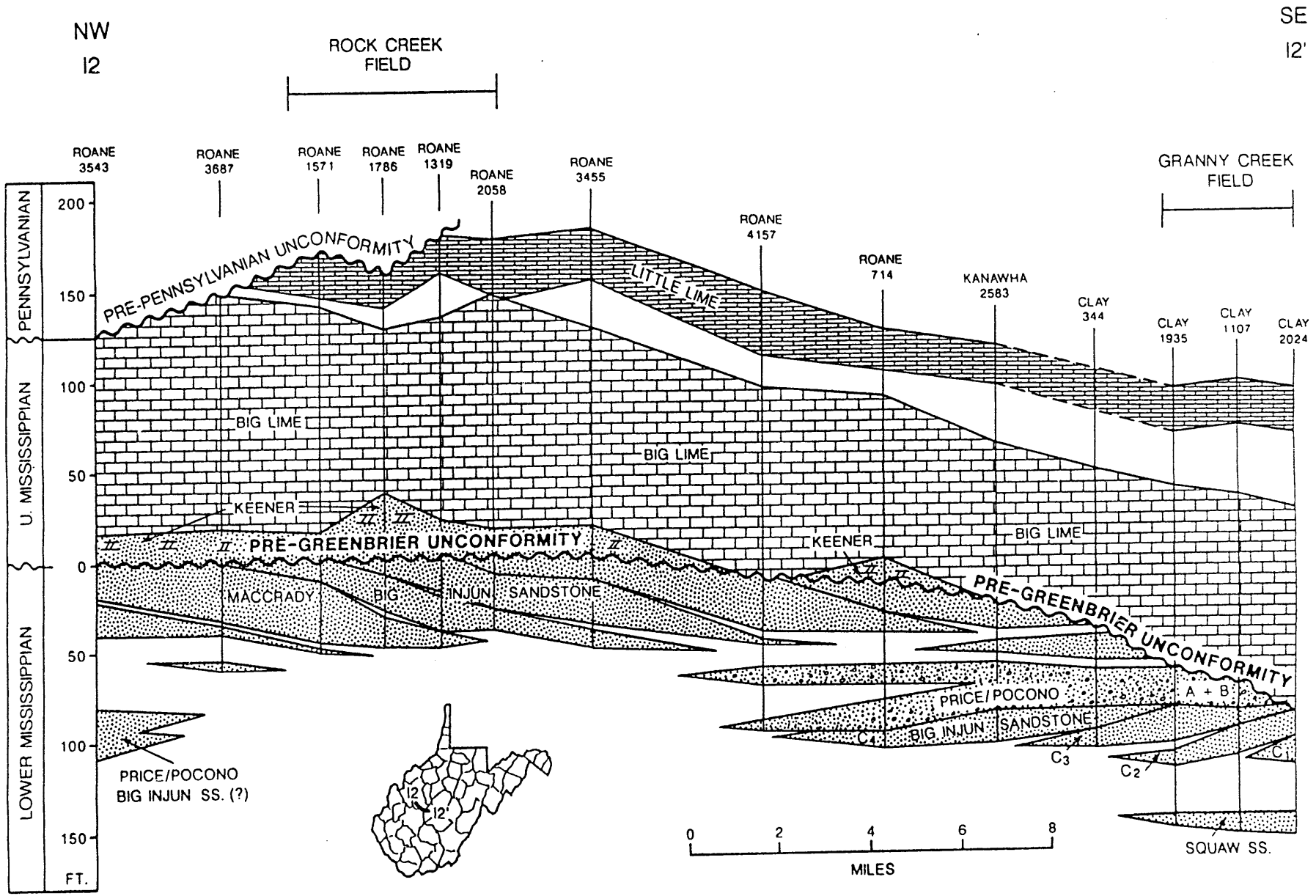

Figure 3. Stratigraphic cross section showing relationships between "Maccrady" Big Injun and Pocono/Price Big Injun reservoirs between the Rock Creek to Granny Creek oil fields. Regional dip since the Mississippian has been to the west. Pre-Greenbrier erosion is related to growth of the West Virginia dome.

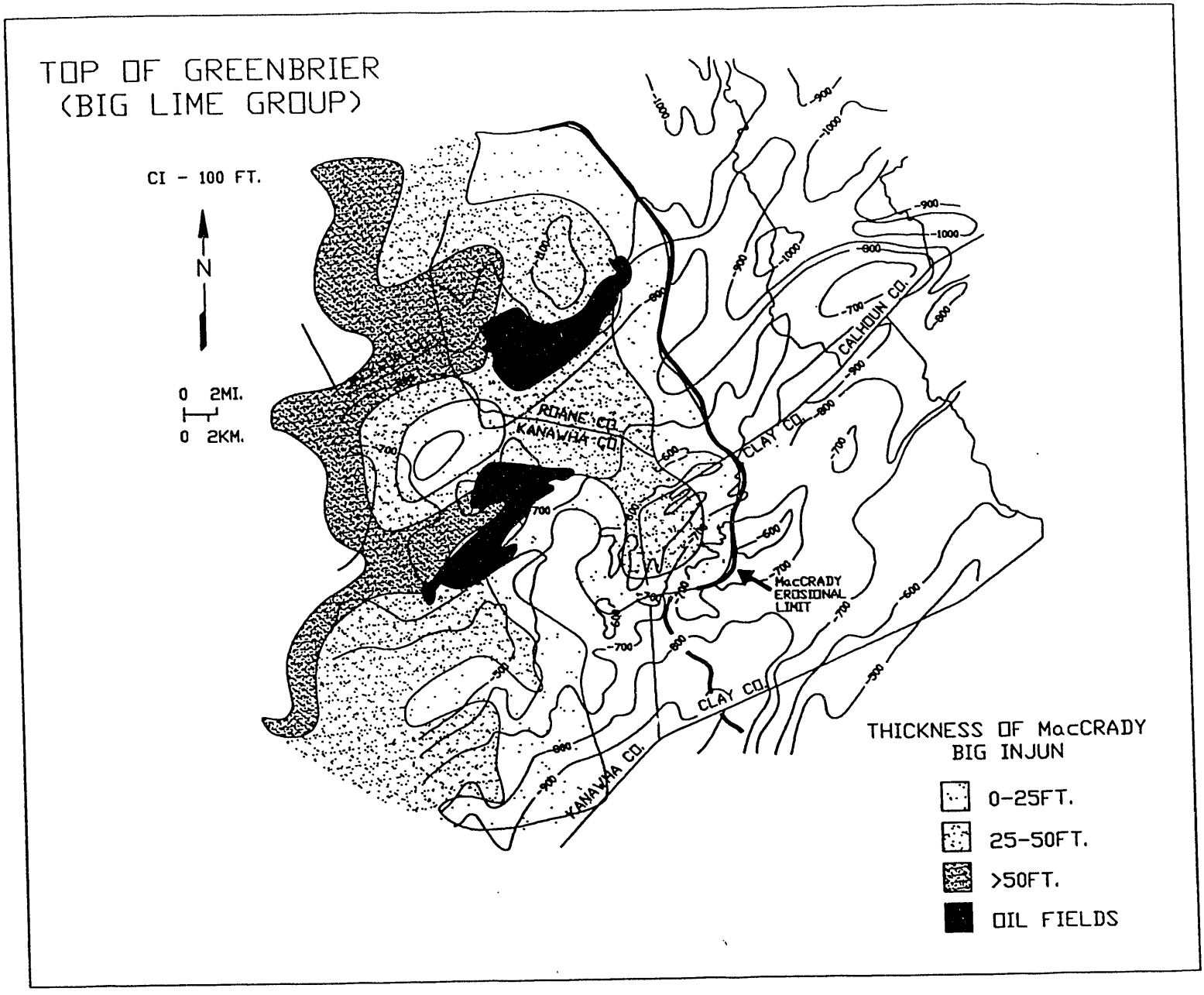

Figure 4.Isopach of "Maccrady" Big Injun sandstone superimposed on Greenbrier structure map (Figure 7) showing oil fields producing from the "Maccrady" Big Injun reservoir.

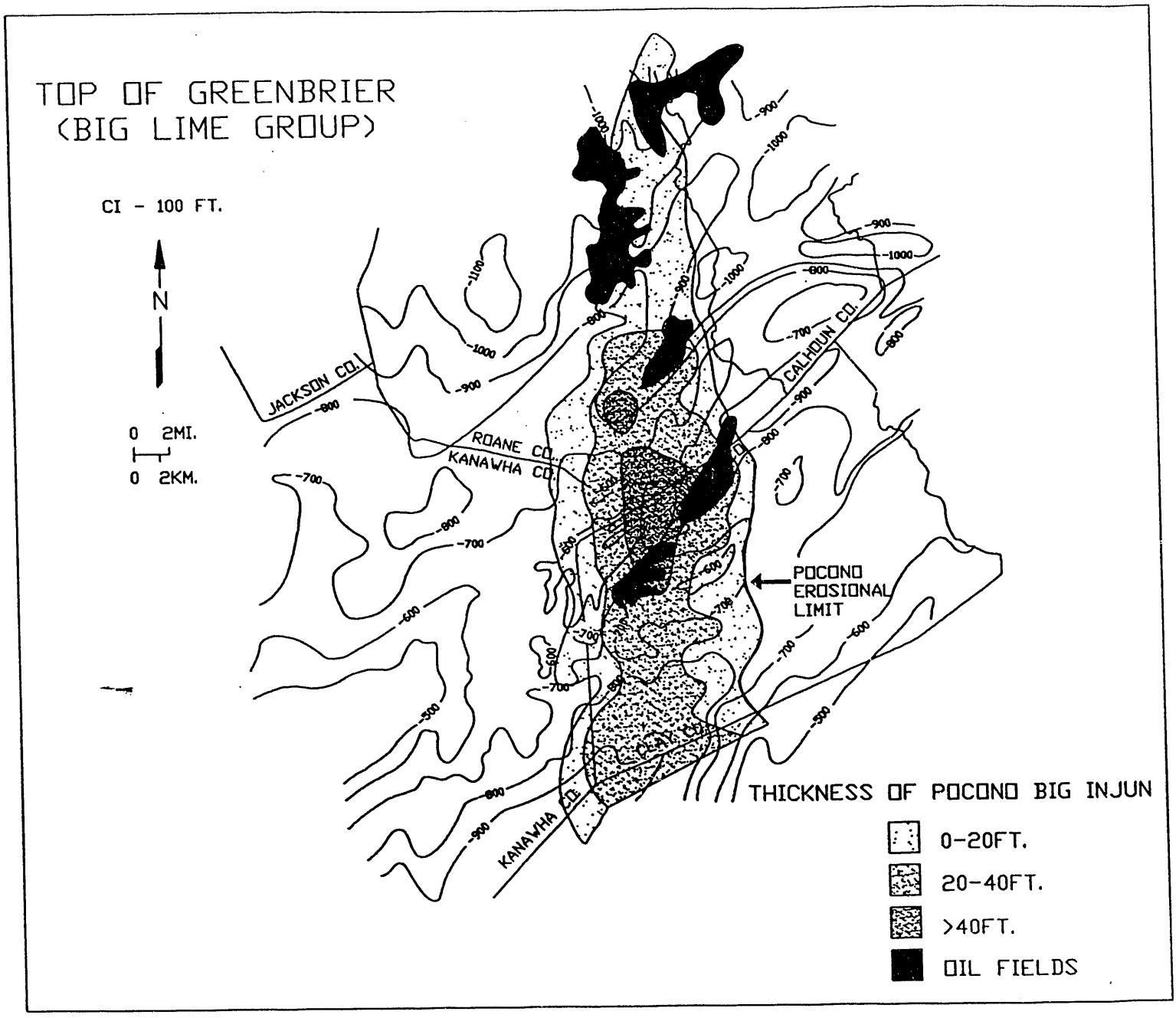

Figure 5. Isopach of Pocono (Price) Big Injun sandstone superimposed on Greenbrier structure map showing oil fields producing from Pocono Big Injun.

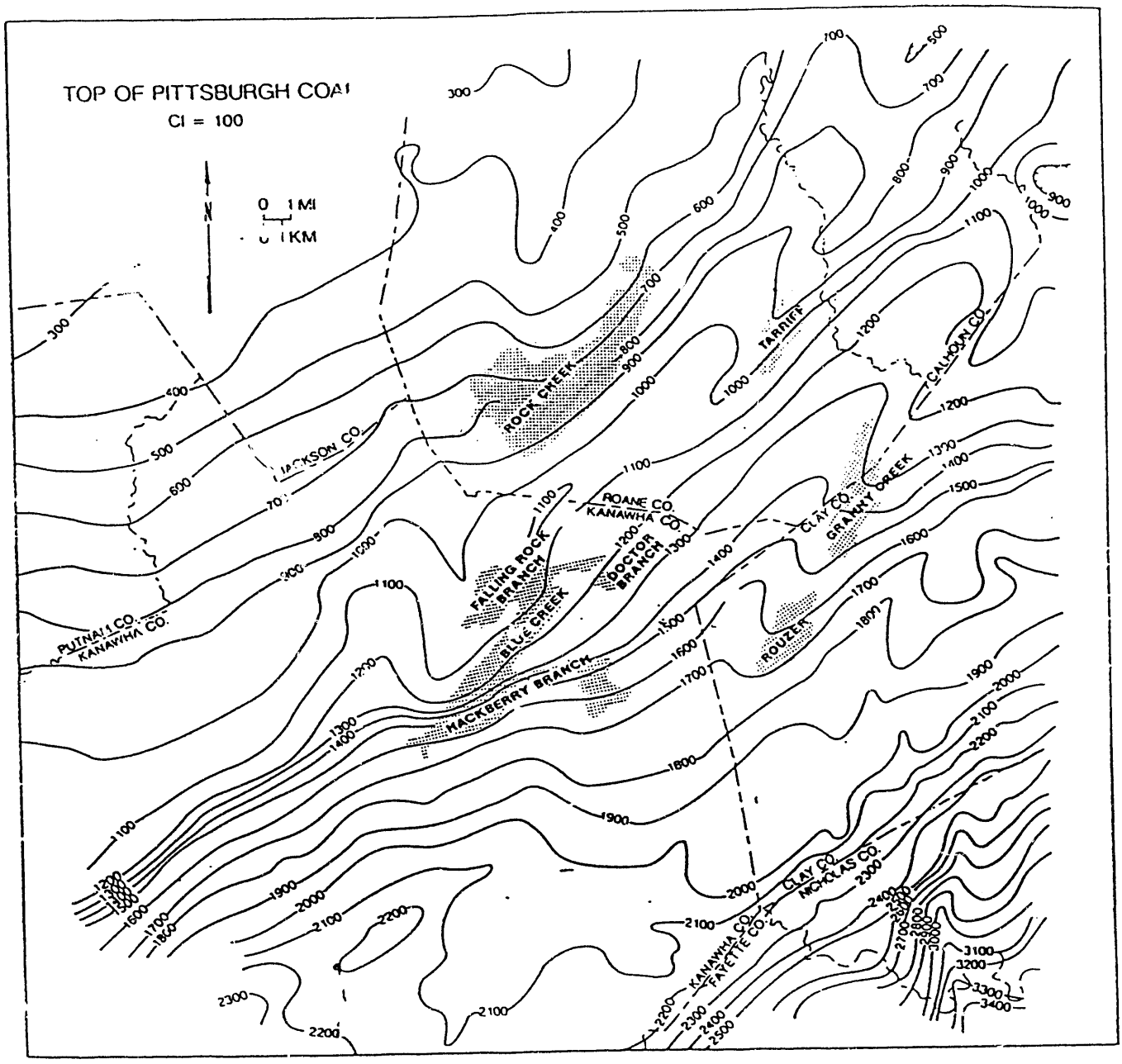

Figure 6. Near-surface structure in the regional study area.

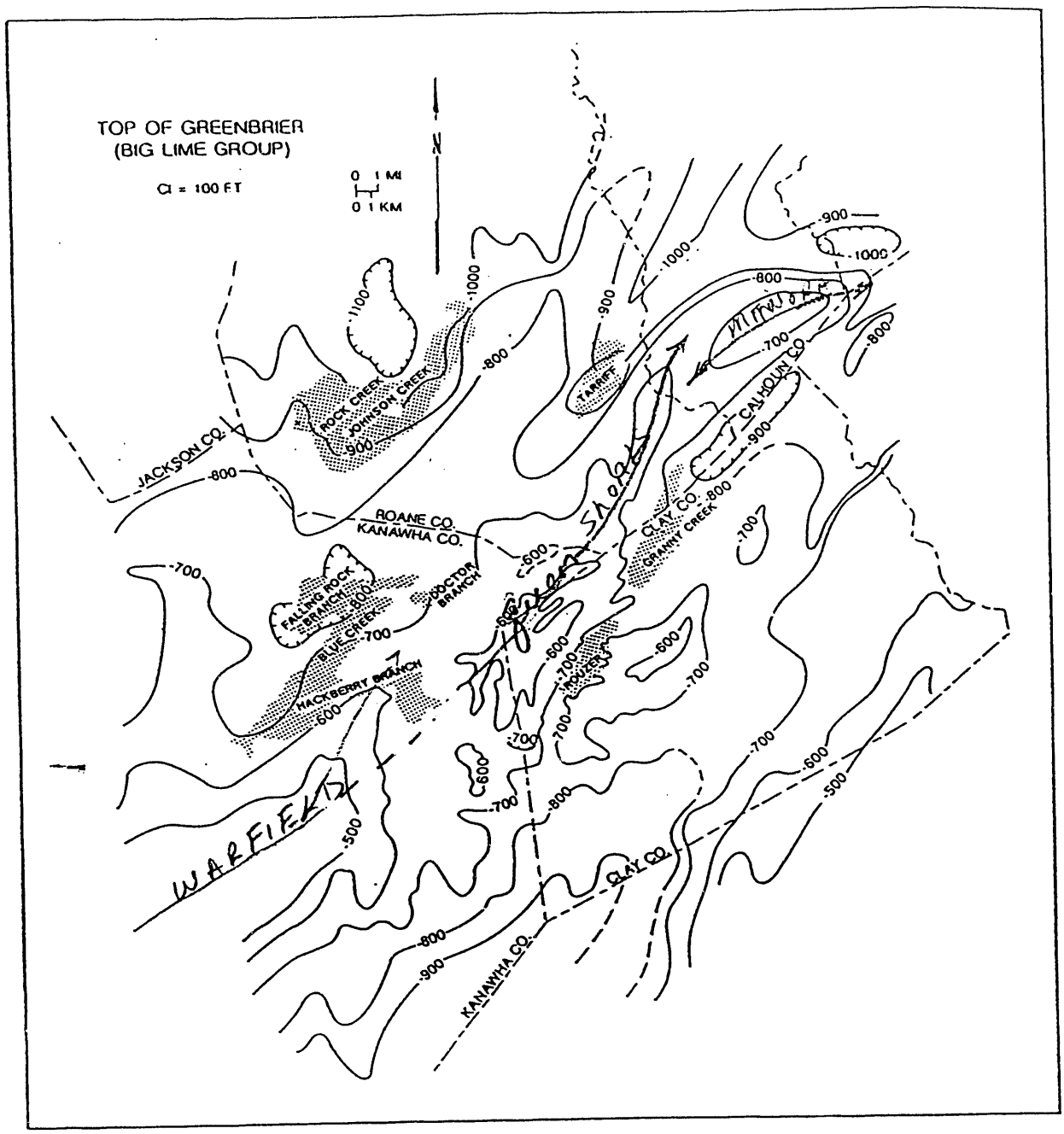

Figure 7. Subsurface structure on top of the (above the Big Injun reservoir, Figure 3)in the regional study area.

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