KENTUCKY GEOLOGICAL SURVEY
UNIVERSITY OF KENTUCKY, LEXINGTON SERIES XI, 1983
Donald C. Haney, Director and State Geologist

KOGA

PROCEEDINGS OF THE TECHNICAL SESSIONS KENTUCKY OIL AND GAS ASSOCIATION FORTY-FOURTH ANNUAL MEETING JUNE 11-13, 1980

In cooperation with Kentucky Oil & Gas Association

SPECIAL PUBLICATION 9

ISSN 0075-5613

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ABSTRACT

Variation in thickness and lithology of subsurface units of the Big Lime (Middle Mississippian) formation in eastern Kentucky can be related to regional and local geologic factors that control stratigraphy and petroleum exploration potential.

Subsurface channels, shoals, and other stratigraphic traps may be related to structural or topographic features such as the extensions of the Waverly Arch and Paint Creek Uplift, faulting expressed by hinge lines, and positive gravity anomalies such as the Perry County and Pike County Uplifts.

Although the principal oil and gas fields produce from a basal porous dolomite found in marine channels that are incised into the underlying Grainger Formation, shows of oil and gas and porosity also occur locally in dolomite and oolitic limestone elsewhere in the section.

A study of well records, including gamma ray and formation density logs, in conjunction with an examination of well cuttings could indicate local development of porous dolomite, oolite, or fractured zones; hydrocarbon shows might indicate potential stratigraphic or structural traps for commercial petroleum accumulation.

INTRODUCTION

Acknowledgments

This paper is an outgrowth of recent local geological investigations in Leslie County, Kentucky, by the senior author and his students who have completed relevant M.S. theses at the University of Kentucky (Okolo, 1977; Ping, 1978; Birch, 1980). Many of the regional relationships and most of the illustrations are based on a subsurface study of the Big Lime in 12 counties in eastern Kentucky by the junior author (Pear, 1980) and in a technical presentation by Pear and MacQuown (1979).

Purpose and Scope

This paper is a summary of significant regional and local paleogeographic and paleostructural features that controlled the thickness, lithology, porosity, and petroleum potential of the Middle Mississippian Big Lime in eastern Kentucky. Emphasis is on factors controlling the principal production in stratigraphic traps, consisting of porous channel dolomites developed locally in the basal Big Lime. Some consideration is given to topographic and structural features that may be significant in localization of reservoirs in other potential dolomitic or oolitic limestone reservoirs in the Big Lime. Detailed descriptions of Big Lime lithology, microfacies, correlation of subsurface and surface units, and relationship of stratigraphy to structure are documented by Pear (1980).

This preliminary regional investigation from the Kentucky-West Virginia boundary to Leslie County, Kentucky, is now being extended to the Kentucky-Tennessee boundary.

Area of Study

The area of study covers approximately 2,500 square miles in parts of 12 counties in eastern Kentucky in the western part of the Appalachian Basin (Fig. 1). Mississippian subsurface units occur several thousand feet below Pennsylvanian rocks exposed at the surface in the Cumberland Plateau Province (Fig. 2). Mississippian rocks outcrop in an irregular linear trend east of pre-Mississippian rocks exposed along the Cincinnati Arch west of the study area, and in a narrow trend along the

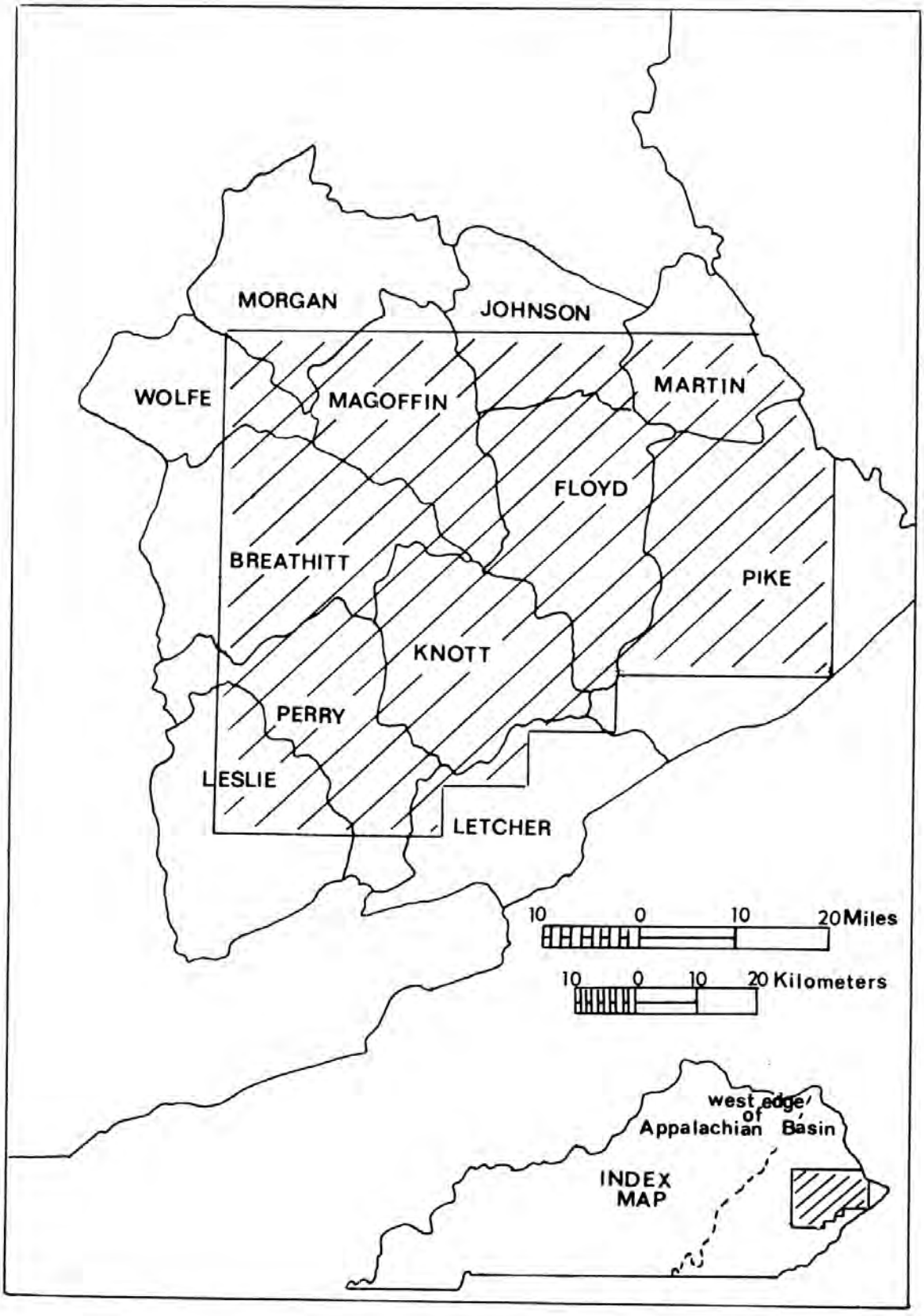


Figure 1. Map showing area of study.

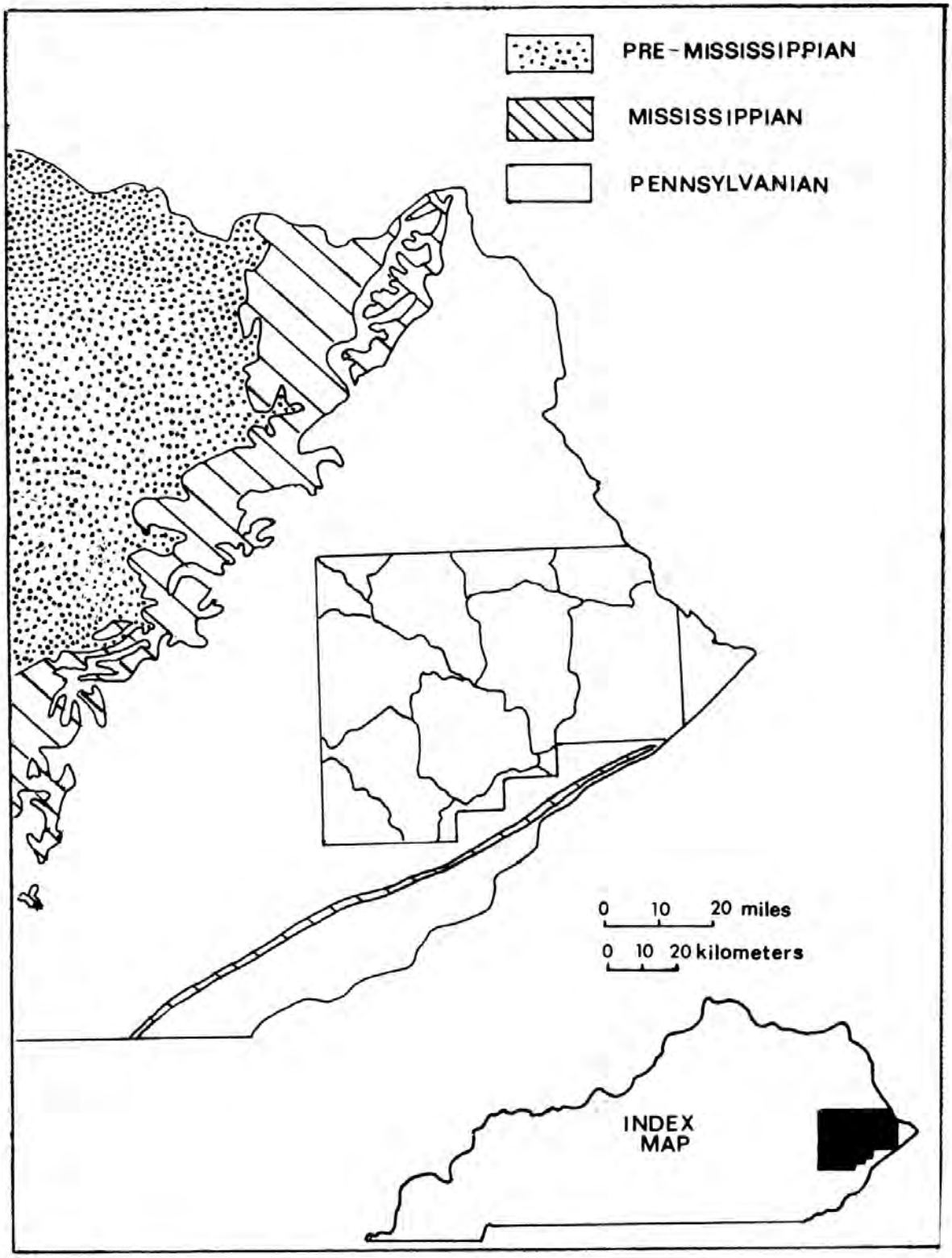


Figure 2. Generalized geologic map of study area.

Pine Mountain thrust fault at the western boundary of the folded Appalachian Mountains near the southeastern boundary of the study area.

Well Data

Information relative to individual wells that penetrate the Big Lime, including operator names, farm names, drillers' logs, mechanical logs, petroleum shows and tests, and well cuttings, is available at the Kentucky Geological Survey in Lexington, Kentucky. Gooding (1980) prepared a new catalog of well samples and cores on file at the Kentucky Geological Survey. Pear (1980) listed well sample localities and selected sample logs used in the study area.

REGIONAL STRATIGRAPHY

General

The Big Lime is one of several informal subsurface units equivalent to formal lithostratigraphic units of the Mississippian Newman Limestone of eastern Kentucky (Fig. 3) and correlative with Middle and early Late Mississippian-aged carbonates of the Mississippi Valley type locality. The principal petroleum production in eastern Kentucky is from dolomitic lithology in the basal Big Lime. However, other dolomitic, oolitic, or other porous lithologies may be prospective, as in western Kentucky, northern Tennessee, and western West Virginia.

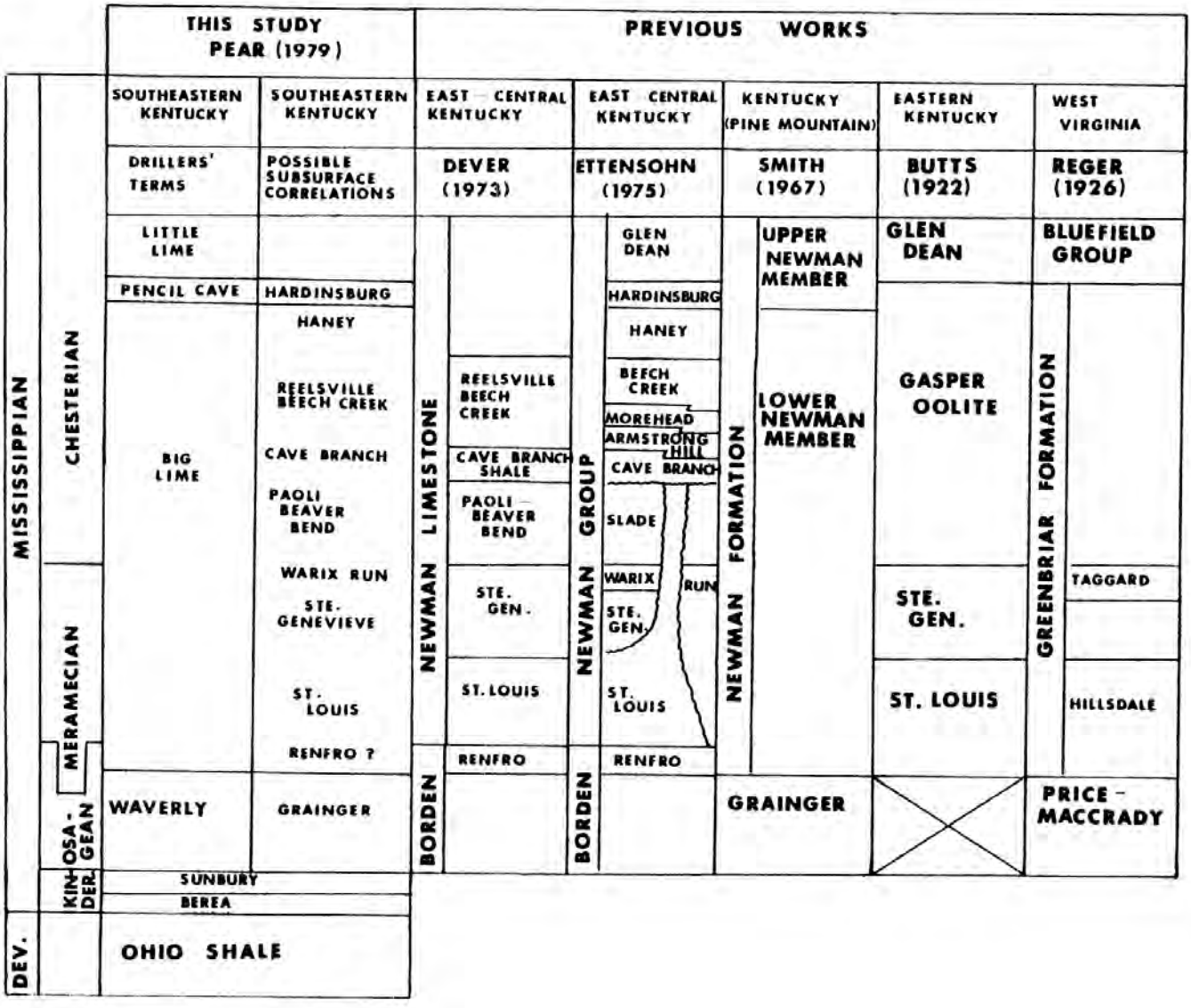


Figure 3. Correlation chart showing relationship between subsurface and outcrop stratigraphy.

Previous Work

McFarlan and Walker (1956) correlated Newman Limestone units with equivalent type Mississippian units of the Mississippi Valley, including western Kentucky. Several authors of local subsurface studies in eastern Kentucky (Greenfield, 1957; Hamilton, 1958; Okolo, 1977) have documented the lithologic equivalence of informal Big Lime units with formal stratigraphic units of the lower Newman Limestone. Recently, Birch (1980) suggested that subsurface units of the Big Lime in Leslie County are correlative with formal members of the Newman Limestone of east-central Kentucky, as defined by Dever (1973, 1980) and Ettensohn (1975). However, the relationship of the basal Big Lime unit to the Renfro and basal St. Louis of surface sections is controversial. All contain dolomite and quartz silt and sand locally.

REGIONAL STRUCTURE

General

The structural framework of eastern Kentucky has had a direct and indirect effect on Big Lime deposition. Significant structural features are illustrated in Figure 4. A number of structural and topographic features are related to tectonism during the Late Precambrian and probable rejuvenation during Paleozoic or later time. Some younger features are possibly directly or indirectly related to Appalachian orogeny tectonism during the closing of the ancestral Atlantic (Iapetus) Ocean. Obvious structural features include domes, arches, uplifts, basins (or troughs), and faults observed on surface or subsurface structural maps. Less obvious evidence of these features depends on the interpretation of geophysical features or the thickness and lithology of stratigraphic units, including the Big Lime and its subdivisions.

Previous and Current Research

The pioneer subsurface work of Woodward (1961) disclosed the presence of a broad north-south structural feature that he named the "Waverly Arch" (Fig. 4). He also recognized an east-west basement fault system that forms the northern boundary of the Rome Trough (McGuire and Howell, 1963). Mississippian and later Paleozoic faulting above the basement fault and the presence of an apical island above the Waverly Arch during deposition of the Big Lime and other Newman Limestone units has been documented by Dever (1973, 1980) and Ettensohn (1975). Recent publications concerning Late Paleozoic synsedimentary tectonism and topographic relief include Dever and others (1977), Ettensohn and Dever (1979), and Ettensohn (1980). A subsurface extension of the Waverly Arch into northern Tennessee was suggested by Englund (1972). Additional evidence is presented elsewhere in the present study. As yet, there is no significant Big Lime production in the sparsely drilled Waverly Arch extension.

Activity along the east-west-trending Irvine-Paint Creek Fault (Fig. 4) during the Late Paleozoic was suggested by Haney (1976) and Horne and others (1976). Dillman (1980) documented growth faulting during the deposition of the Chattanooga Shale (Upper Devonian-Lower Mississippian) along several faults in the Rome Trough. Dohm (1963) described Late Paleozoic tectonism along the Paint Creek Uplift (Fig. 4). The southern extension of this uplift in the study area is evidenced by some thinning and shallow-water lithology of Big Lime units and is discussed elsewhere in this paper.

Two local gravity highs, the Pike County and Perry County Uplifts (Fig. 4), may represent Precambrian basement topography above an area underlain by Precambrian mafic intrusives (Ammerman and Keller, 1979). Ping (1978) suggested that the Perry County Uplift may have been a positive feature that influenced local facies distribution during Middle Pennsylvanian time. The Hyden West Pool on the western side of the Perry County Uplift and the Cutshin Pool on the eastern side produce petroleum from channels paralleling the flanks of the uplift.

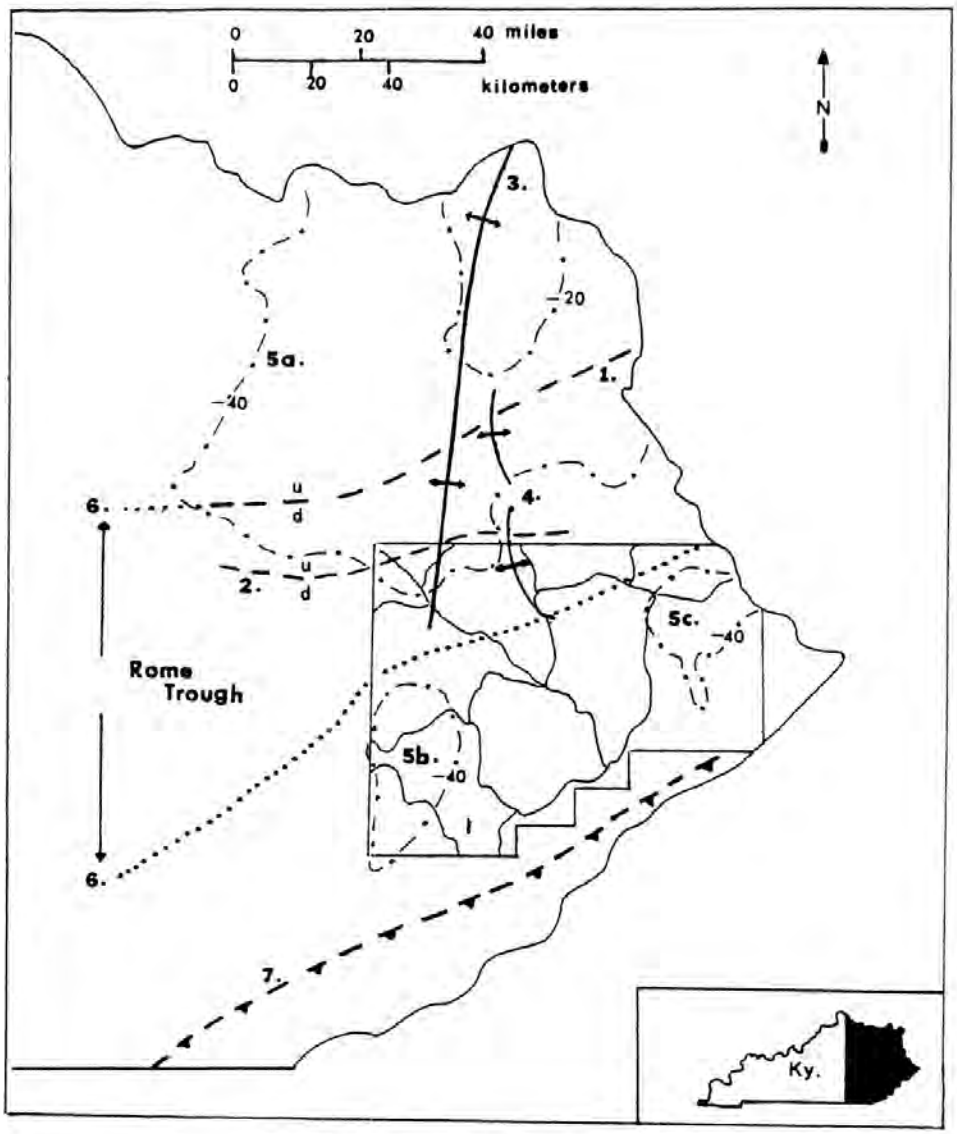
The Pine Mountain Overthrust near the southeastern boundary of the study area was displaced during the Late Paleozoic Appalachian orogeny and therefore had no effect on Big Lime thickness or depositional environments. However, there may be other associated late structural features such as the Paint Creek Uplift (extended) in the southeastern part of the study area, where well control is limited, that could serve as structural traps for petroleum accumulation in porous oolitic or dolomite lithologies. Late structural features similar to the Paint Creek Uplift may be present in the vicinity of the Pine Mountain Overthrust in an area of sparse well control. If so, they might provide local traps for petroleum accumulation in porous oolitic or dolomitic Big Lime lithologies.

The relationship of production relative to a northeast-southwest-trending hinge-line zone along the eastern side of the study area is discussed later (see Stratigraphic Variation and Fig. 5). A local study has been made of the important Bull Creek Field on the Perry-Letcher county boundary (Webb, 1972).

SUBSURFACE STRATIGRAPHIC UNITS

General

Subsurface stratigraphic units consist of four calcareous lithologic units, each of which is overlain by a thin, shaly marker bed with a characteristically high



Explanation

1. Basement Fault System
2. Irvine-Paint Creek Fault System
3. Waverly Arch (Early Paleozoic axis) (Woodward, 1961)
4. Axes of Paint Creek Uplift (Dohm, 1963)

5a-c. Bouguer gravity anomalies, in milligals

- 5a. McGuire and Howell, 1963
- 5b. Perry County Uplift
- 5c. Pike County Uplift (Ammerman and Keller, 1979)

6. Boundaries of Rome Trough (Ammerman and Keller, 1979)
7. Pine Mountain thrust fault

Figure 4. Regional structural framework of eastern Kentucky.

gamma-ray signature on mechanical logs (Fig. 6). Stratigraphic units were considered in detail by Pear (1980). In some field areas, the lowermost lithologic unit (unit 4) contains a separate basal dolomitic subdivision referred to as unit 5 by Birch (1980) and as the basal St. Louis dolomite by some geologists. This porous basal dolomitic unit is the principal petroleum reservoir in the Big Lime of eastern Kentucky.

The lithologic units consist of dominantly light- to medium-gray, fossiliferous and oolitic limestone facies

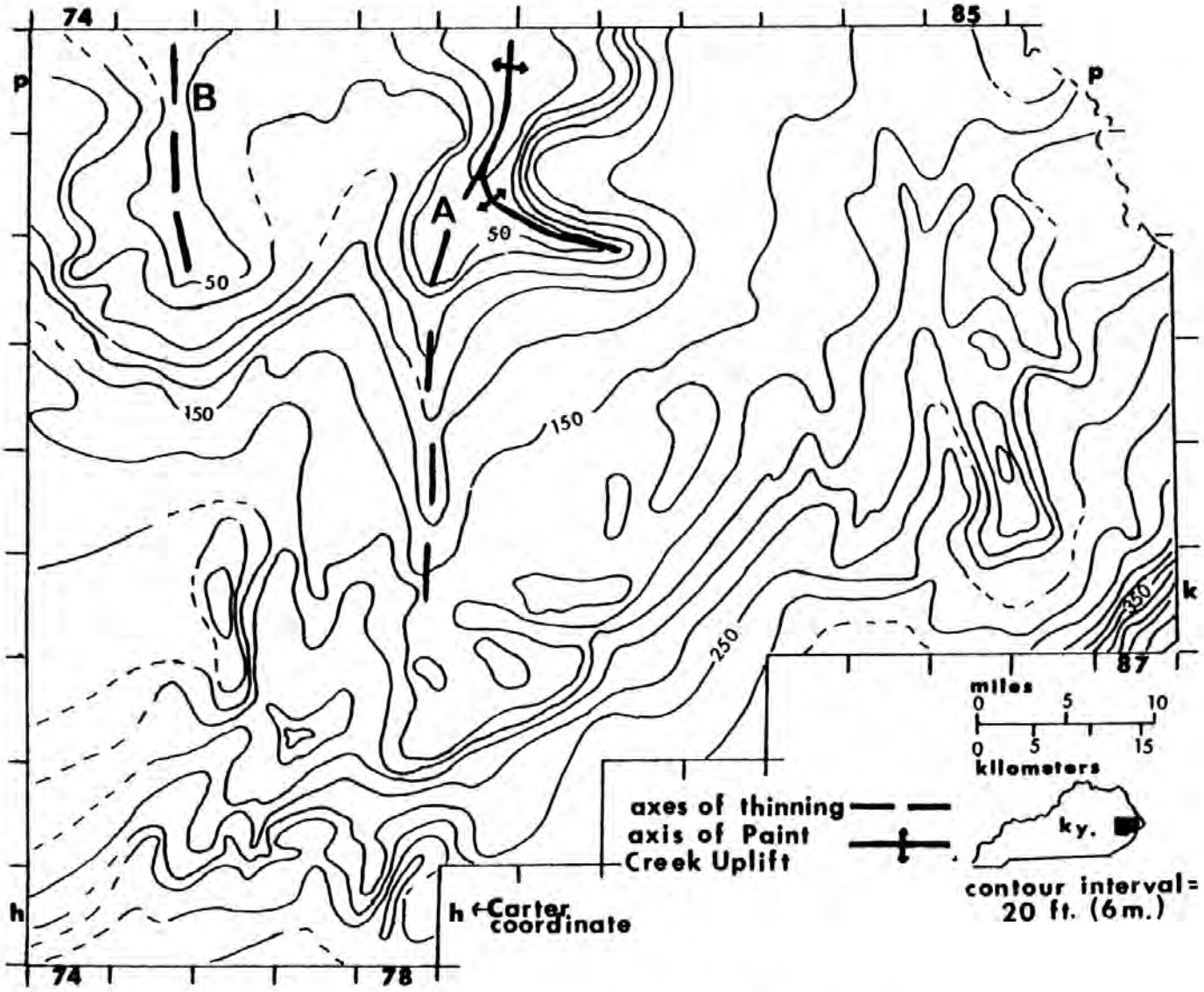


Figure 5. Axes of thinning located from the Big Lime isopach.

and minor dolomite that vary regionally and locally in thickness and composition. Microfacies vary from calcareous mudstones to packstones and grainstones with skeletal fragments, peloids, lumps, and minor chert or sparse detrital quartz, as described by Pear (1980).

The marker beds are relatively thin, generally dark-gray to gray-green, argillaceous and calcareous marine shales that are regionally persistent but locally thin or absent. Shale markers may represent episodes of clastic influx during carbonate deposition or periods of decreased carbonate production, and thus provide an approximate time framework for separating lithologic units. The locally absent yellow-brown to red shale markers of the lower Big Lime, containing local dolomite and subaerial crusts, are evidence for periods of maximum sea regression, whereas the more continuous gray-green shale markers of the upper Big Lime that were deposited in less oxydizing submarine environments are evidence of periods of maximum sea transgression. Supporting evidence is contained in lithologic units described below. Inconsistency in the selection of the top of the Big Lime results from difficulty in recognizing the uppermost marker bed (the Pencil Cave, marker bed a) in some localities.

The lower Big Lime lithologic units (4, and to a lesser extent 3) are more variable in thickness and lithology than the upper units (2, 1). They exhibit some upward shoaling and very shallow marine characteristics such as an increase in shallow-water oolite facies, minor dolomite facies, laminations or crusts, and oxidized brown to red shales of possible subaerial origin, and an upward decrease in fossils of shallow marine origin.

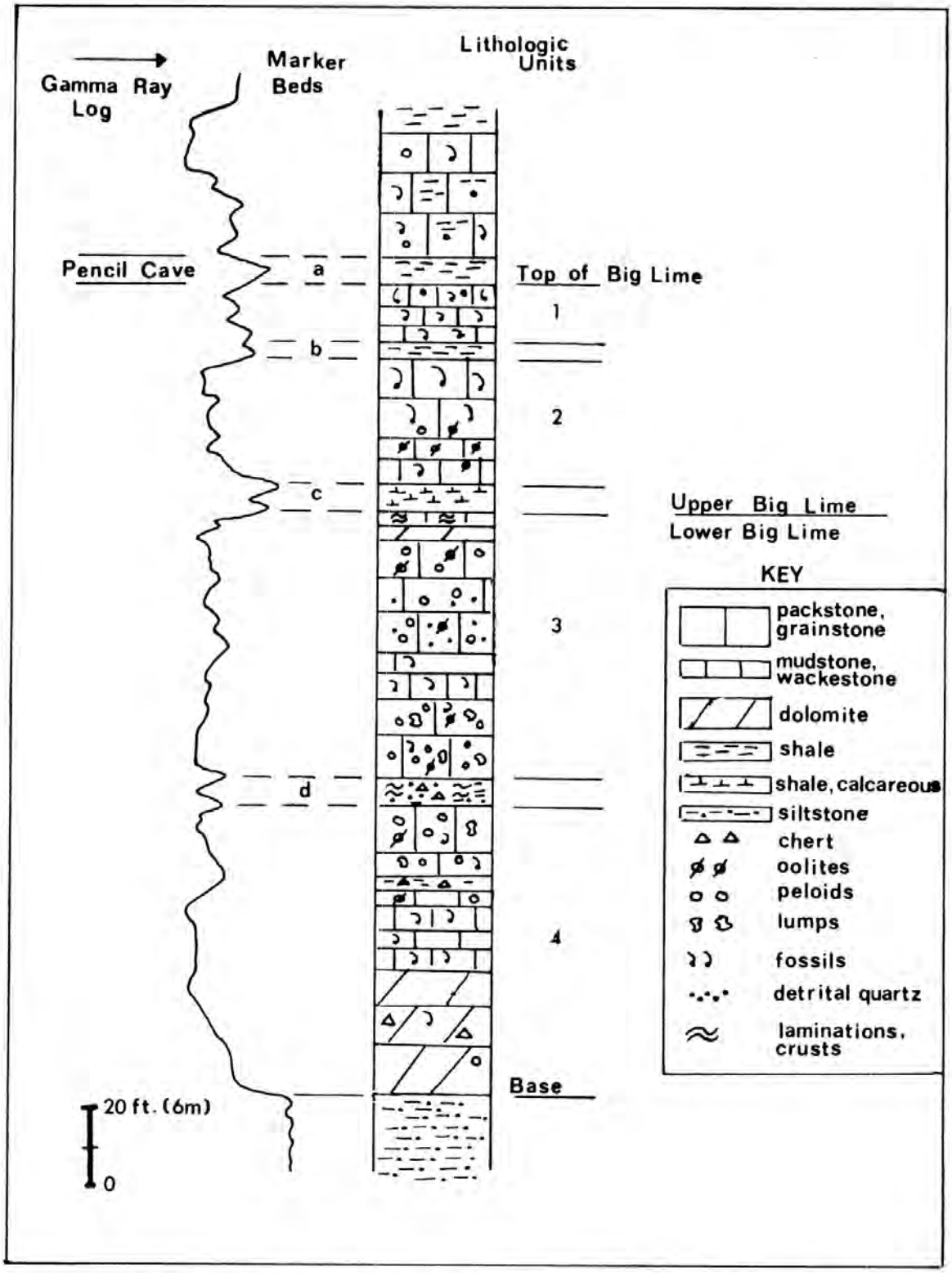


Figure 6. Generalized Big Lime columnar section with subsurface units and marker beds.

The upper Big Lime lithologic units (2, 1) exhibit slightly deeper shallow marine characteristics such as thin beds with minor lateral thickness or facies variation, abundant marine fossils, absence of subaerial exposure features, and persistent, thin, gray or green-gray, shaly marker beds.

Similar cyclicity of lithologic units and marker beds in the Mississippian has been documented elsewhere in

the United States, for example by Swann (1964), and in recent years in Europe by Ramsbottom (1973). The origin of transgressive and regressive phases is controversial, but regional eustatic sea-level changes resulting from climatic or plate tectonic activity have been proposed, as well as tectonic activity related to basin subsidence or local uplift. Regression can also result from deposition of carbonates on a shallow shelf.

The basal dolomite in unit 4 (unit 5 of Birch, 1980) is the principal producing unit in the Big Lime, but shows of oil in minor sucrosic dolomite and porous oolitic zones throughout the Big Lime may be prospective locally. Known production occurs in equivalent zones in western Kentucky, Tennessee, and West Virginia. Detailed mapping may indicate the presence of local porous, oolitic bars or shoal trends, dolomite-filled channels, or oolitic or dolomite facies associated with local topographic or structural features formed during or after Big Lime deposition.

The subsurface lithology of the Big Lime was described in some detail by Pear (1980) and Birch (1980); some characteristics of individual units follow.

Grainger Formation (Waverly)

Probable shallow marine channels that cut into the green and red siltstones and shales of the Grainger Formation (Waverly) are the sites of deposition of the overying porous basal Big Lime dolomite, the principal petroleum reservoir. Local thick sections of the Big Lime may thus indicate the presence of such channels.

Unit 4

Basal unit 4 is more variable in lithology and thickness, both locally and regionally, than other Big Lime units. Birch (1980) recognized a basal subunit (unit 5) in the Hyden West Pool, deposited in a shallow marine channel incised into the underlying Grainger Formation, probably during initial transgression of the Big Lime seas. Facies consist of alternating dolomite and minor limestone. Although some sucrosic dolomite is unfossiliferous and primary, possibly deposited under evaporative conditions in shallow restricted marine channels, some secondary dolomite with pinpoint and vuggy porosity appears to be a diagenetically altered fossiliferous limestone or dolomitic limestone. Interbedded limestone and dolomitic limestone contain normal marine fossils including foraminifera, brachiopods, crinoids, and bryozoans deposited in the channels during normal marine incursions. Subunit 5 can be locally overlain by a relatively thick, dark, shaly marker bed with a high gamma-ray signature, referred to as the "hot zone," probably consisting of radioactive organic matter, which may have been a marine marsh deposit of late channel environments. The basal part of unit 4 in nonchannel areas is less dolomitic and the overlying hot zone is thin or missing. Minor red or green shaly laminae, similar to Grainger lithology, occur locally.

The cherty, dark, finely crystalline limestones of unit 4 are characteristic of St. Louis lithology, whereas the overlying oolitic limestones are typical of Ste. Genevieve lithology. Stratigraphic equivalency will require additional study. The basal dolomite could be basal St. Louis or equivalent to the underlying Renfro dolomite of the upper Borden group.

Marker D

This sparsely fossiliferous, yellow-brown, shaly mudstone contains quartz silt, orange chert, laminated crusts, intraclasts, and red iron stain. Marker D may represent a period of regression of Big Lime seas with possible subaerial exposure. In the southeastern part of the study area where continuous deposition occurred, the marker is thin or absent.

Unit 3

Although lateral variations in thickness are less evident in unit 3 than in unit 4, lithologic variation in this yellowish-brown oolitic and skeletal calcarenite is similar. Calcilutites and minor dolomites occur locally. Local detrital quartz in the lower part is similar to that of the Warix Run Formation (Ettensohn, 1975), which is of possible equivalent age in surface outcrops. Micrite-coated grains of possible algal origin are common in unit 3. The upper part of the unit may be correlative with the Paoli-Beaver Bend of surface sections. Laminated calcitic mudstone and subaerial crusts, thin dolomite, and birdseyes indicate a shoaling-upward sequence with intertidal to supratidal features.

Marker C

Marker C, consisting of greenish-gray to locally grayish-red calcareous shale with rounded clasts of micritic limestone, is the lowest marker correlative throughout the study area and may be equivalent to the Cave Branch Shale of surface sections.

Unit 2

Unit 2 is a yellowish-brown oolite and skeletal calcarenite with local occurrences of calcilutite and crystalline dolomite. The unit grades upward from shallow-water calcilutites, oolites, and dolomite to slightly deeper water skeletal calcarenites. Facies are generally more widespread and less variable in composition and thickness than lower units in the Big Lime. The unit is equivalent to the Reelsville-Beech Creek of surface sections.

Marker B

Marker B is a widespread, dark-greenish-gray, fissile marine shale and may be equivalent to the basal part of the Haney Member of the Newman Limestone of surface sections.

Unit 1

The uppermost unit of the Big Lime is a thin-bedded, yellowish-brown, slightly dolomitic calcilutite grading upward to calcarenite. Thin, greenish-gray shales are interbedded with the limestones. Some greenish inclusions are replacement chert. Diverse marine fossils are commonly whole, and the unit is probably equivalent to the Haney of surface sections.

Marker A

Marker A, the Pencil Cave of drillers, is a dark-gray to greenish-gray, noncalcareous shale that separates the Big Lime from the overlying Little Lime, which is generally darker, more argillaceous, and locally contains more detrital quartz than the Big Lime. Where thin or absent, all or part of the overlying Little Lime may be erroneously included with the Big Lime, as discussed below. The Pencil Cave is equivalent to the Hardinsburg of the upper Newman Limestone (Ettensohn, 1975).

Little Lime

The Little Lime, a darker, more argillaceous limestone than the Big Lime, contains detrital quartz locally. Where the underlying Pencil Cave has not been recognized, part or all of the Little Lime may be mistakenly included with the Big Lime. In such cases this erroneous Big Lime thickness can be a source of error on isopach maps. The Little Lime is equivalent to the Glen Dean of the uppermost Newman Limestone (Ettensohn, 1975).

STRATIGRAPHIC VARIATION

Variation in the thickness and lithology of Big Lime units, shown on cross sections and maps, provides evidence for regional and local geologic factors that controlled the stratigraphy, porosity development, and petroleum accumulation.

Cross sections and isopach maps indicate the paleogeography and paleostructure at the time of deposition. For example, thin units may be evidence of limited deposition, erosion, or differential compaction on shallow submarine topography or on active structural highs, where later preserved lithology indicates relatively shallow depositional environments. Conversely, thick units may be evidence of more continuous deposition in local channels or regional troughs or basins. Lithology is the key to interpretation of relatively shallow or somewhat deeper original depositional environments.

Maps of present-day structure are not included because they are less useful than isopach maps. Present-day structure maps can mask or distort evidence for older structural events and their accuracy depends on correctly surveyed elevations of control wells. However, they may be useful in exploration where original stratigraphically or structurally controlled petroleum is redistributed by later tectonism.

Although the principal Big Lime petroleum reservoirs in eastern Kentucky occur in porous dolomite in shallow marine channels, shallow-water oolitic shoals, beaches, or channel fill, and dolomite in various shallow-water environments contain local porosity and shows of oil or gas and may be prospective petroleum reservoirs.

REGIONAL CONTROLS

Regional Thickness Variation

Regional thickness variation depends on the paleogeography during Big Lime deposition, and is diagrammatically shown on Figure 7, that was reconstructed from regional cross sections (Figs. 8-10) and the isopach map of the Big Lime (Fig. 11). The shallower cratonic environments (northwest of the basin) were areas of minimal deposition and maximal erosion. The indicated subenvironments on the craton were delineated on the basis of rates of thickening that are of lesser magnitude on the stable Northwest Platform and Shelf, but greater on the unstable Platform Slope and Hinge Line, where structural instability (normal faulting?), leading to faster rates of subsidence, could account for greater rates of thickening. Maximal subsidence and thickness occurred in the Appalachian Basin.

Thickness variation of individual Big Lime lithologic units from northwest to southeast is particularly evident in basal lower Big Lime unit 4, which also exhibits the greatest lithologic variation.

Regional Facies Variation

Platform and shelf facies, subject to more oxidation erosion and physical energy than basin facies, are lighter colored and contain subaerial features such as exposure crusts and more shallow marine features such as birdseyes and oolites.

Basin facies, deposited in a less oxidizing environment, are darker and contain more clastics (particularly shale) than shelf facies. Units are more difficult to distinguish because cyclicity is less evident where subsidence is more continuous.

Intergradation of facies occurs in both shelf and basin environments, particularly in the hinge-line area,

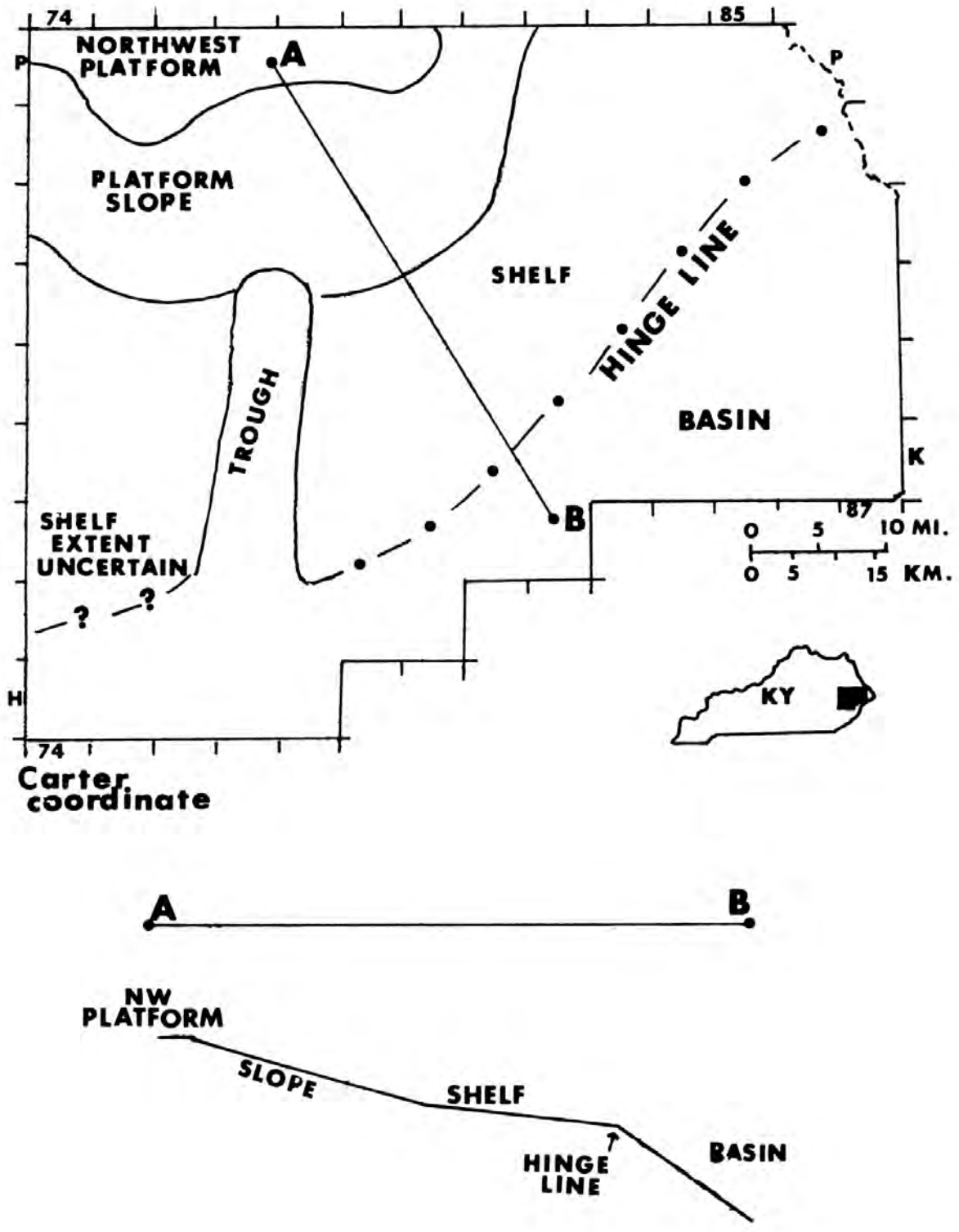


Figure 7. Paleogeography during Big Lime deposition.

because of marine transgression and regression in response to changing climatic and tectonic factors through time. These factors account for eustatic changes in sea level, differential or variable subsi-

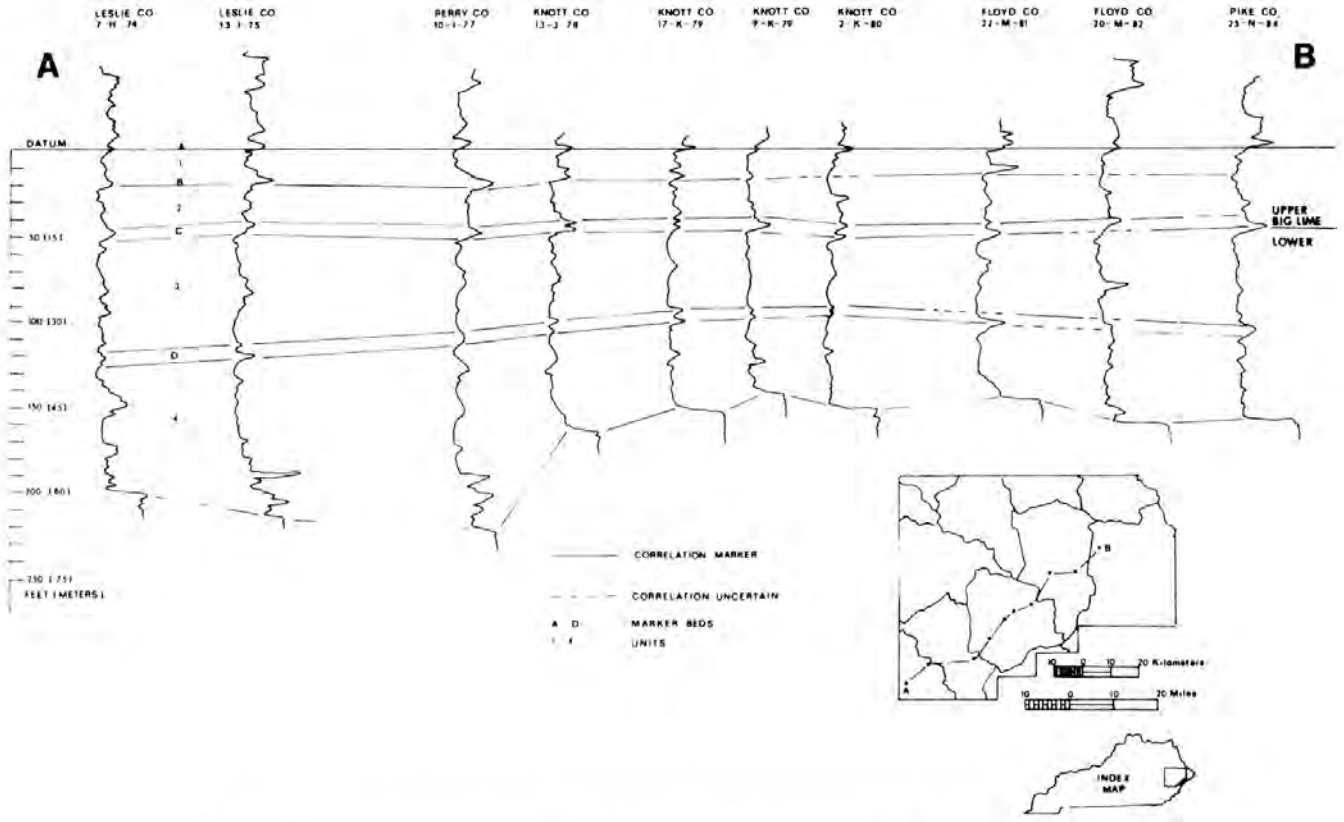


Figure 8. Big Lime cross section A-B, parallel to depositional strike, derived from gamma-ray log.

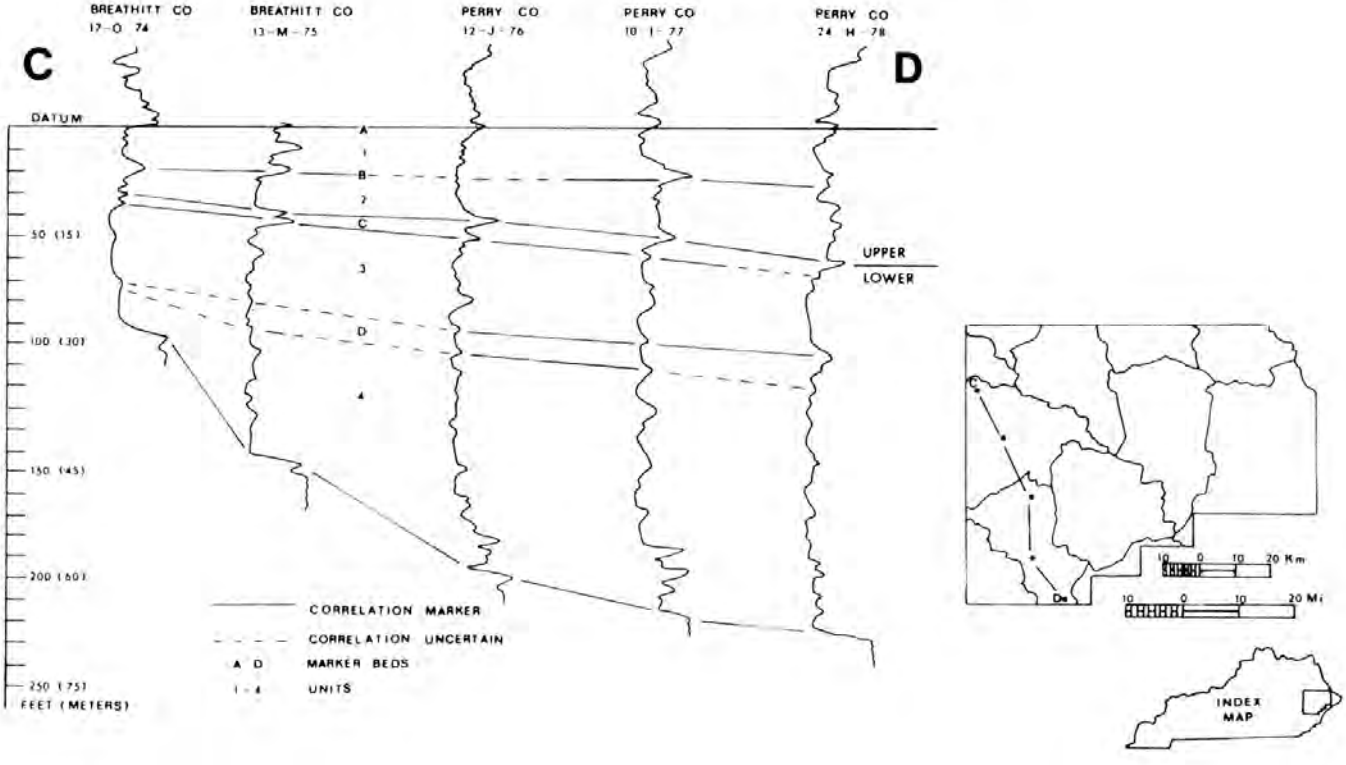


Figure 9. Big Lime cross section C-D, parallel to depositional high, derived from gamma-ray log.

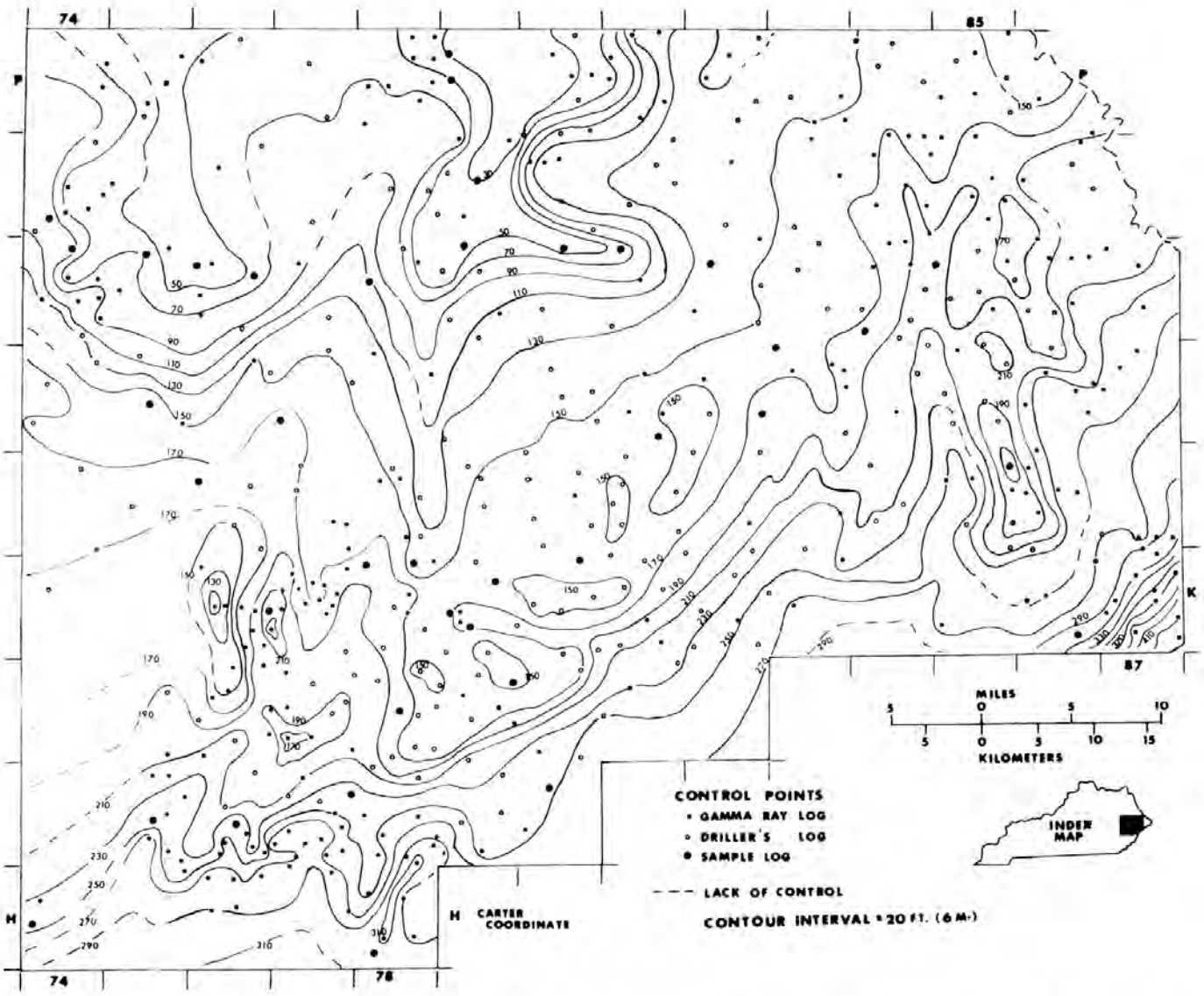


Figure 10. Cross section E-F, across depositional dip, based on gamma-ray logs, demonstrating regional Big Lime thickness variation.

dence of the sea floor, and periodic variation in the rate of carbonate shelf deposition and clastic influx.

Intertonguing facies may provide stratigraphic traps for petroleum, which may be independent of local structural or topographic control.

LOCAL CONTROLS

Local factors controlling stratigraphic variation are more difficult to evaluate than regional factors, but are more important in localizing commercial accumulations of petroleum. In general, they can be related to local structural or topographic influence present before or during deposition of Big Lime units.

Shoals and Islands

Thin, shallow-water lithologies on shoals or islands in Big Lime seas may overlie preexisting topographic or structural highs. Draping and differential compaction over buried hills or fault scarps below unconformities are well documented in the literature. Subdued replicas of such features may persist during later deposition. Rejuvenation of tectonism also can create positive topographic features during sedimentation. Shoals or islands above structural or topographic features are sites of thin, subaerial or shallow-marine sedimentation resulting from limited local deposition or erosion. Porous zones with shows of oil and gas have been ob-

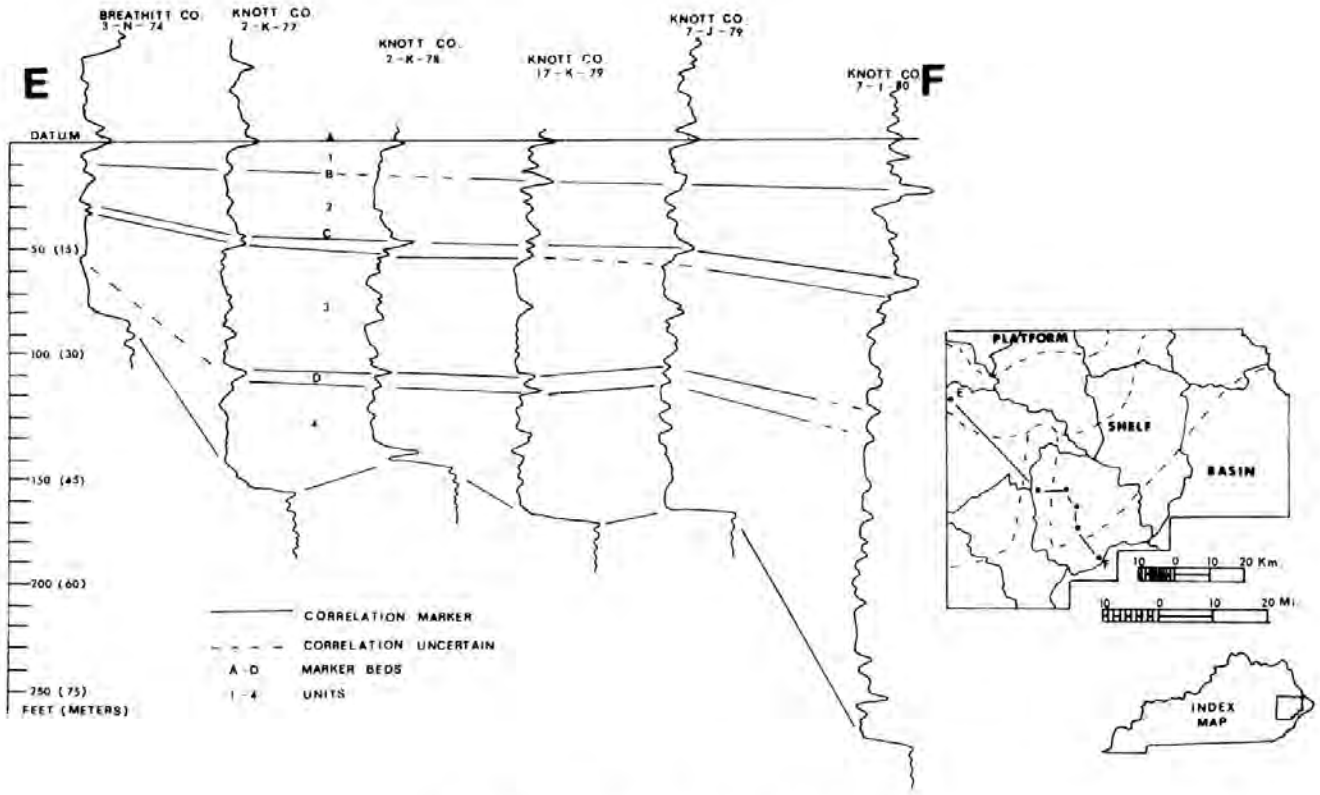


Figure 11. Regional Big Lime isopach map.

served locally in oolitic shoals or channels, in sucrosic dolomite, and in fractures possibly associated with faulting. Although such reservoirs are not well documented in eastern Kentucky, they are productive from equivalent lithologies in Meramecian and Chesterian limestones of the Illinois Basin, the Monteagle of Tennessee, and the Greenbrier of West Virginia (Fig. 3).

Thin, shallow-water lithologies in the study area occur above the Waverly Arch extended (axis of thinning B on isopach map, Fig. 5; cross section, Fig. 12) and to some degree on the Paint Creek Uplift extended (axis of thinning A on isopach map, Fig. 5; cross section, Fig. 13). The Early Paleozoic Waverly Arch proper, north of the study area, was tectonically rejuvenated during Big Lime deposition and was exposed in part as a topographic island according to Dever (1973, 1980) and Ettensohn (1975). Although structural movement along the Paint Creek Uplift is thought to have occurred mainly after deposition of the Big Lime, the presence of some thinning and shallow-water deposits above the Paint Creek Uplift (extended), as shown in Figure 13, may indicate minor structural movement or positive topography in the area during Big Lime deposition. Other areas of thin Big Lime lithologies that may be prospective that have further detailed documentation are indicated on the isopach map (Fig. 5) or the regional isopach map (Fig. 11).

Local Basins and Channels

Continuous local deposition on sea floor depressions resulted in relatively thick Big Lime sections such as in the trough area shown in Figure 7. This trough and other local basins are documented by a cross section (Fig. 10) in addition to the local and regional isopach maps (Figs. 5 and 11).

Some local thick Big Lime sections deposited in troughs contain a thick, basal, nonporous, nonproductive dolomitic limestone in unit 4. The formation density log indicates porous and nonporous zones; examination of well cuttings is required to determine the lithology of this basal unit. Thick Big Lime sections may indicate the presence of thick, porous, basal St. Louis dolomite in local channels (unit 5 of Birch, 1980, or basal unit 4 of Pear, 1980). The St. Louis is the principal petroleum-producing unit of the Big Lime in such fields as the Hyden West Pool near the western boundary of the study area (Birch, 1980). Oil and gas fields are commonly found where the basal dolomite is present (Fig. 12).

The channels that contain the producing thick basal dolomite and related limestones with marine fossils previously described are thought to be of marine origin (Birch, 1980; Pear, 1980). Tidal currents, associated with transgressing Big Lime seas, may have aided in scour-

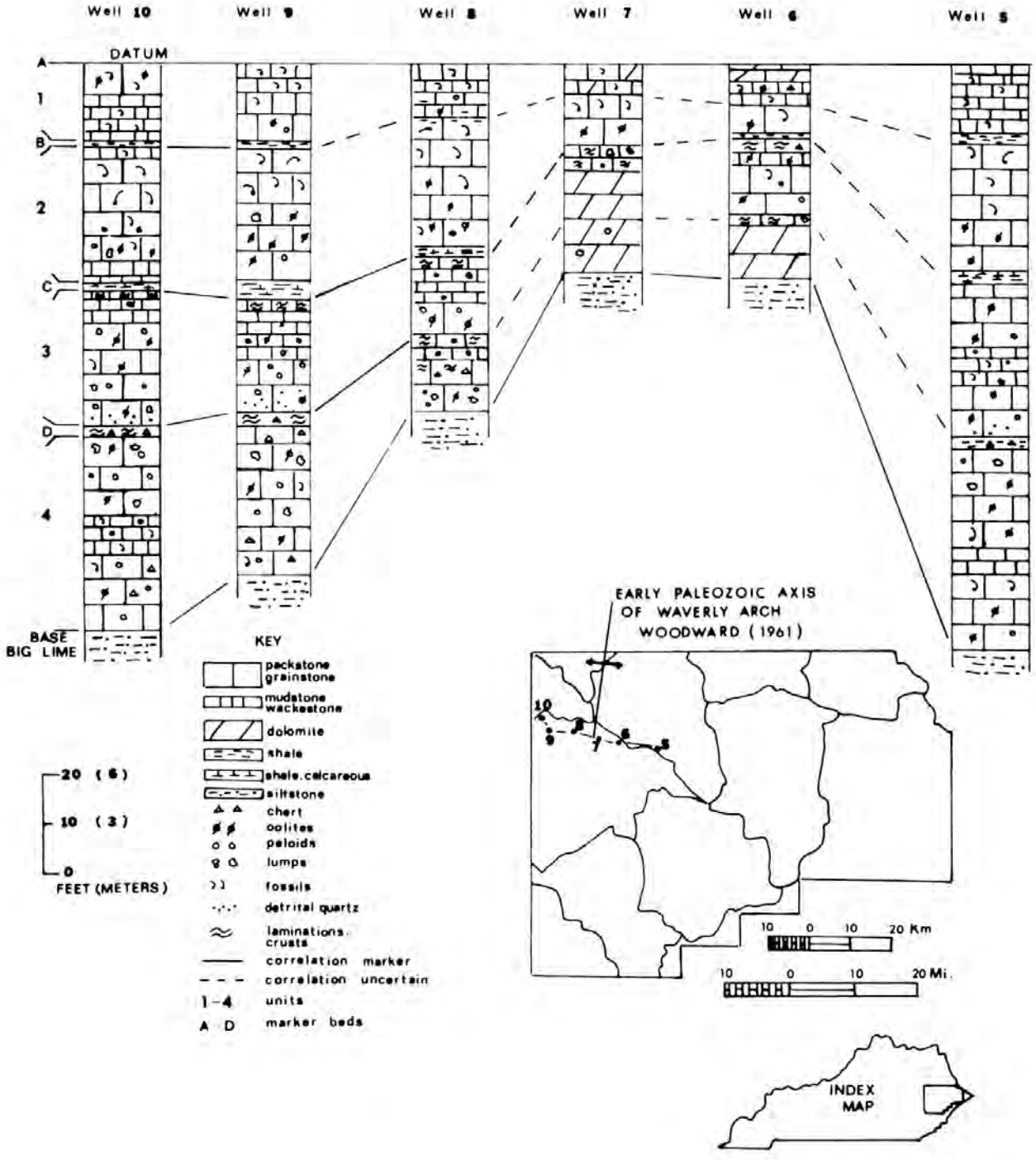


Figure 12. Cross section across the Waverly Arch extension showing variable thickness, lithology, and unit recognition.

ing channels in irregular, possibly embayed topography in the underlying Grainger Formation.

Features Related to Gravity Anomalies

Local, positive Bouguer gravity anomalies such as the Perry County and Pike County Uplifts have been interpreted as basement highs in part (Ammerman and Keller, 1979). Draping of younger formations over older topography could have created a topographic high on the Grainger surface that might have deflected marine currents during the transgression of Big Lime seas. If so, the channels cut by these currents and the petroleum-

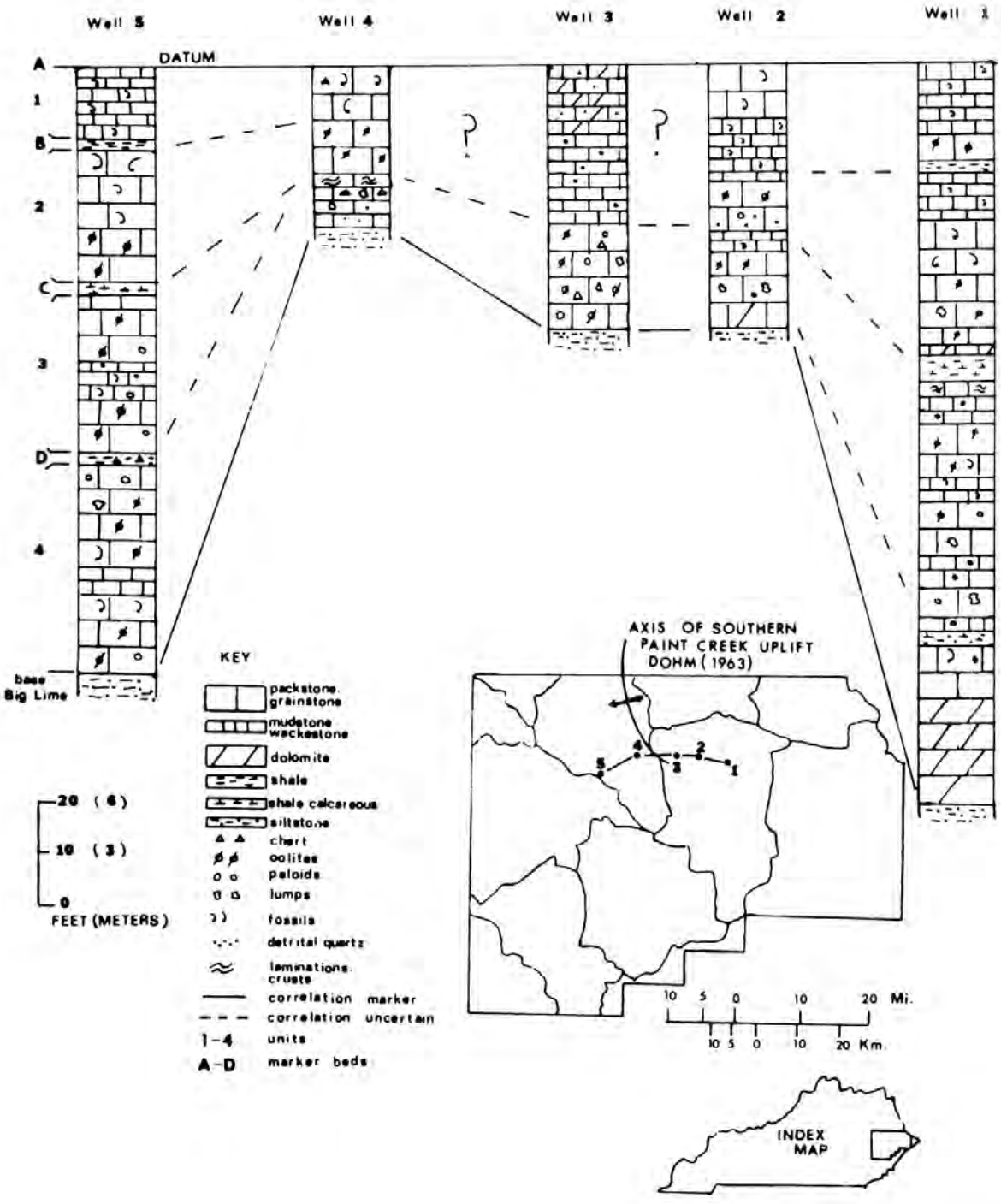


Figure 13. Cross section across the Paint Creek Uplift showing variable thickness, lithology, unit recognition, and correlation.

producing channel-fill dolomite in the basal Big Lime might be expected to occur above the flanks of some positive gravity anomalies. For example, the Hyden West Field occurs on the western flank of the Perry County Uplift and the Cutshin Field is being developed on the eastern side. An idealized sequence of events that could explain these relationships is shown in Figure 14 and summarized as follows.

Stage 1: Thinning of pre-Mississippian units over Precambrian basement high indicated by the positive

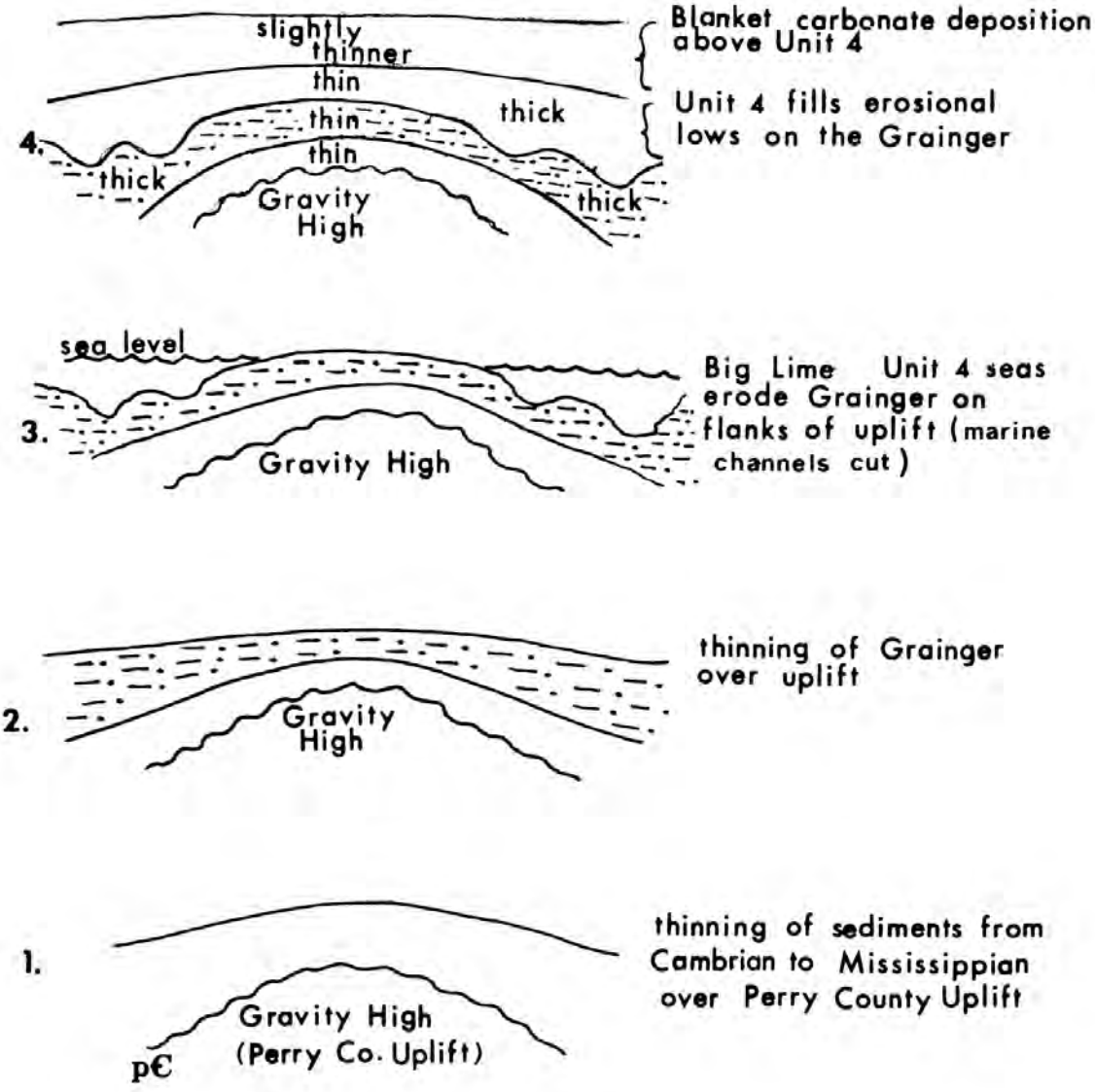


Figure 14. Idealized sequence demonstrating relationship of Big Lime and Grainger thickness to the Perry County Uplift.

gravity high of Ammerman and Keller (1979). Thinning was caused by nondeposition, erosion, or differential compaction.

Stage 2: Similar thinning of the Lower Mississippian Grainger Formation.

Stage 3: Shallow marine channels cut in the Grainger Formation by tidal currents on the flanks of a topographic shoal or island during the transgression of early Big Lime seas.

Stage 4: Deposition of the thick basal dolomite (or limestone) of unit 4 (unit 5 of Birch, 1980) in marine tidal channels, followed by blanket deposition of subsequent Big Lime carbonate units, and minor thinning over the uplift. Similar relationships may

exist in the vicinity of the Pike County Uplift of Ammerman and Keller (1979), but they have not been investigated.

Some negative gravity anomalies may represent topographic lows on the Precambrian basement, such as the Floyd County Channel that lies between the Perry County and Pike County Uplifts (Ammerman and Keller, 1979). Thick Big Lime sections, representing deeper facies above such lows, may be less prospective for petroleum production if favorable local shallow-water lithologies are poorly developed.

Local Facies Variation

Local facies of lithologic units on the Wavery Arch extended and the Paint Creek Uplift (Figs. 12, 13) are relatively thin and are dominantly dolomitic or oolitic with other shallow-water lithologies such as pelletal fossiliferous limestones, minor detrital quartz, subaerial crusts, and some oxidized iron oxide stain (hematite or limonite), which imparts a reddish or brown color to local shaly limestone. Although drilling is sparse on some other local structure or topographic features, similar lithologies might be expected above gravity highs such as the Perry County and Pike County Uplifts or other minor highs shown by thins on isopach maps (Figs. 5, 11). Conversely, thick areas above local lows contain fewer shallow-water characteristics, with less dolomite, and darker, less oxidized, lithologies.

Possible petroleum production in oil-stained, porous oolite shoals or sucrosic dolomite may occur on local highs. Examination of well cuttings in conjunction with mechanical logs may indicate prospective areas.

CONCLUSIONS

Both regional and local geologic factors control stratigraphic thickness and lithology, which are important in exploration for petroleum in the Big Lime (Middle Mississippian) of eastern Kentucky.

Variation in the rate of thickening of the Big Lime and included lithologic units is used to identify regional, northeast-southwest-trending paleogeographic subdivisions on the craton and adjacent deeper Appalachian Basin to the southeast. Principal fields, in the basal porous dolomite, occur on a carbonate shelf and the adjacent basin near a hinge-line zone, which extends southwestward from similar producing provinces in West Virginia.

The basal primary sucrosic dolomite and interbedded dolomitic limestone with marine fossils are believed to have been deposited in shallow marine channels cut in irregular topography on the underlying Grainger Formation (Waverly) by transgressing Big Lime seas. Therefore, thick, linear patterns on Big Lime isopach maps have been used to explore for producing basal dolomite trends, along with favorable porosity trends based on data from formation-density logs. Secondary dolomitization of limestone beds in the basal Big Lime has created moldic and vuggy porosity by solution of calcitic fossils and intercrystalline porosity resulting from replacement of limestone by dolomite. Because some thick Big Lime sections do not contain well developed, porous basal dolomite, microscopic examination of well cuttings is an important adjunct to prospecting based on mechanical logs alone.

Some basal Big Lime stratigraphic trap reservoirs may be controlled in part by local topographic or structural features. The Cutshin and Hyden West Pools, for example, may lie on the flanks of a Mississippian topographic high possibly draped over a basement high indicated by a positive gravity anomaly in Perry and Leslie Counties.

Local structures such as southerly extensions of the Waverly Arch and the Paint Creek Uplift are identified by thin Big Lime lithologic units with characteristic shallow-water facies, including dolomite and oolitic limestone. These facies exhibit local porosity and hydrocarbon shows and could be prospective on local structures or as stratigraphic traps similar to those producing petroleum from Big Lime equivalents in the Illinois Basin, Tennessee, and West Virginia. Although well control is sparse, detailed geologic investigations including examination of well cuttings, mechanical logs, and drillers' logs are needed to localize prospective areas.

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POLYMER—A PRACTICAL APPROACH TO ENHANCED OIL RECOVERY

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ABSTRACT

Polymer injected into producing wells as a water control treatment is an effective enhanced oil recovery (EOR) tool to increase oil production revenue and decrease water production costs. It is used in injection wells as a diverting agent; it changes flow patterns to permit bypassed productive zones to be flooded. It is also used as a mobility control; it increases ultimate oil recovery from waterfloods. Polymer-augmented waterflooding is encouraged through price and tax incentives by the Federal government.

INTRODUCTION

The meaning of "enhanced oil recovery" has been clouded by the various meanings developed by the public and special interest groups. Within the industry, both major and independent oil companies have differing views about its potential. The increasing involvement of the government in enhanced oil recovery is becoming more apparent at all levels. Enhanced oil recovery is important today because the biggest source of hydrocarbon reserves is in fields already discovered. These reserves are the major part of the original oil in the reservoir that could not be recovered by conventional producing processes. Because this huge potential is ready for the taking, industry and government are dedicating vast amounts of resources. The U. S. Department of Energy (DOE) and the Internal Revenue Service (IRS) have officially sanctioned various enhanced oil recovery techniques through incentive programs to promote expanded activity. A list of these accepted processes is shown in Table 1.

To the average oil producer, enhanced oil recovery refers to any means that permit an operator to increase the amount of recoverable oil or to improve the operational economics of existing producing properties. Polymers can provide a practical approach to enhanced oil recovery. Polymer chemicals can be effective in water control at individual production or injection wells. Polymer chemicals can effectively improve mobility control in reservoirs under water flood. However, it is not feasible to conduct an efficient mobility-control program without a reasonable water-control program. Because of this prerequisite, water control will be discussed first.

Table 1.—Enhanced Oil Recovery Techniques.

Miscible Fluid Displacement
Conventional Steam-Drive Injection
Unconventional Steam-Drive Injection
Microemulsion Flooding
Polymer-Augmented Waterflooding
Cyclic Steam Injection
Alkaline Flooding
Immiscible Nonhydrocarbon Gas Displacement
Enhanced Heavy Oil Recovery

WATER CONTROL

Water control, as used in this discussion, relates to the remedial treatment of producing or injection wells to correct specific reservoir defects. Some of the defects that lead to adverse movement of water are (1) channels caused by high permeability zones or natural or induced fractures, (2) water coning resulting from natural or artificial water drives, (3) irregular well patterns, and (4) significant differences in development timing.

Objectives

In order to gain control of or alter flow factors in an adverse water condition, in either a producer or injector, the product or service used should:

1. Create resistance to flow in existing channels. It should preferentially reduce relative permeability to water and not significantly affect relative permeability to oil.
2. Provide deep penetration in order to achieve effective resistance.
3. Use relatively large volumes in order to achieve deep penetration.
4. Be low cost because of the large volumes involved.
5. Be relatively long lasting in its effects in order to be economically desirable.

Selection of Producing Wells

Factors used to identify possible candidates for water-control treatments in producing wells are:

1. High water-oil ratios. High ratios generally indicate high lifting costs.
2. Highly permeable thief zones. These intervals are often detected in core and log data.
3. Bottom water coning. Such a condition is often typical of a water-free producer suddenly reverting to high water rates.
4. High rate of fluid production. Flow conditions can be altered by reducing the relative permeability to water.
5. High fluid level in the well. This condition normally suppresses flow of oil from tighter zones. Lowering the fluid level will reduce bottom-hole pressures that permit production from some zones overcome by the hydrostatic head of the fluid in the hole.
6. Definite oil-water contact. A definite contact often indicates a water-coning condition.
7. Low water-oil ratio on initial completions. If a producing well initially produced water-free oil, chances are good that later water production can be reduced.

Treatment Parameters

Various assumptions must be made when designing a water-control treatment with polymer chemicals. Whatever the source of the water problem, few operators will be able to define the dimensions; therefore, estimates based on similar conditions encountered in previous treatments are used. The procedure and considerations taken in treatment design are:

1. Determine the thickness of the water-bearing zone. This is generally the most difficult factor to quantify. The zone will often be represented by only about 10 to 20 percent of the net productive interval.
2. Cause treatment materials to penetrate to a reasonable distance in order to effectively change flow patterns to a producing well. However, the distance should not be so great that treatment costs or productive down time are excessive. Treating volumes are normally designed for radial penetration of 30 to 50 feet.
3. For obvious reasons, maintain treating pressures below formation fracture pressures.
4. Maintain pumping rate at a slow pace, generally below three barrels per minute.
5. Maintain concentration of polymer at maximum levels, within pressure and rate limitations.
6. Taper polymer concentration throughout the job to conform to pressure and rate limitations.
7. Minimize treatment time because of the high cost of truck-mounted pumping equipment. Treating time generally can be held to 1 day.

Production Well Treatment Results

Table 2 shows results of a recent water-control treatment on a high-volume well in Kansas. This well was treated with 1,200 barrels of polymer solution. Prior to treatment, the average lease production was 20 barrels of oil per day (bopd). The well tested at 8 bopd and 700 barrels of water per day (bwpd) with a high fluid level in the hole. Following treatment, lease production showed a 60 to 70 bopd gain and a 50 percent reduction in water. Total cost to the operator for all expenses related to this job was $14,000.

At the end of 30 days, the operator had realized a net profit of $20,000 after payout of all treatment costs. The well has sustained these rates of improved production. Such improvement can often be maintained for long periods of time, although repeated treatments have

Table 2.—Polymer Water Control in a Producing Well.

LOCATION:	Ellis County, Kansas
FORMATION:	Arbuckle lime
TREATMENT DATE:	March 11, 1980
PRODUCTION BEFORE TREATMENT:	20 bopd for lease 8 bopd, 700 bwpd for well
PRODUCTION AFTER TREATMENT:	For lease
1st week	101 bopd avg.
2nd week	74 bopd avg.
3rd week	58 bopd avg.
4th week	49 bopd avg.
1st 30 days	69 bopd avg.
TREATMENT:	1,200 barrels polymer
TOTAL JOB COST:	$14,000

ECONOMICS:

Total job cost paid out in 9 days. Additional revenue for the first 30 days after treatment was $20,000 above treatment costs, taxes, and royalty. Treatment resulted in reduced water production of 8,400 barrels during first 30 days.

shown increased profitability. Table 3 shows evidence of retreatment results. In two of the three wells, increased oil production for 60 days following the retreatment exceeded the response of the initial treatment over a comparable time.

A few of these jobs have been successfully conducted in Kentucky, and good responses have also been seen in treatments in Illinois and Indiana. Examples of three such jobs in Indiana are shown in Table 4. These wells are not particularly spectacular; however, because of water-control efforts, there is a productive oil well instead of no well at all.

The conclusions drawn from many polymer treatments performed on producing wells throughout the world are that the effective and dramatic reduction of the water-oil ratio is a practical stimulation tool to revive marginal wells. This is enhanced oil recovery.

Treatment Parameters of Injection Wells

Parameters for treatment of injection wells are:

1. Low-cost chemicals to permit large-volume treatments. Larger volumes of chemicals are used in injection well treatments than in producing wells. Typical volumes range from 10,000 to 30,000 barrels. The chemical solutions are applied at normal well injection rates, for treating periods of 2 to 6 weeks.
2. Deep penetration. Larger chemical volumes permit deeper penetration from injection wells than similar treatments in producers. Volumes are designed to permit radial penetration from 150 to 200 feet.
3. Low polymer concentration. In order to maintain conventional injection rates, a relatively low concentration of polymer is used. The average concentration is about 500 ppm. During the course of the treatment, the flow characteristics of the polymer solution will be altered by cross-linking agents or necessary additives to cause a gradual buildup in pressure. This will cause resistance to flow in the high-conductivity zones.
4. Stability. The material must be stable in the reservoir environment. The material is nonsolidifying and is always mobile under sufficient pressure. The material is self-healing if a zone parts because of excessive pressure or closes because of fall-off of pressure. The material can be chemically destroyed if there is a need to remove undesirable effects.
5. Maximum flexibility in adapting to existing injection facilities. Single or multiple well treatments can be conducted using small chemical proparting pumps.

Injection Well Treatment Results

Table 5 shows results of a sandstone treatment in Garvin County, Oklahoma. This treatment is a fairly dramatic example of how water control can produce significant results. The escalated value of crude oil makes such a gain highly profitable. In addition, an increasingly important factor is the potential savings due to decreased water production. Production costs are higher for a barrel of water than for a barrel of oil. In this instance, the total reduction of 216,300 barrels of produced water would pay many times for the cost of the water-control treatment.

Table 6 shows the results of a multi-well treatment in a sandstone reservoir in southern Oklahoma. Thirteen wells were treated simultaneously. This treatment was

Table 3.—Results of Polymer Water Control in a Producing Well.

	LOCATION	FORMATION	TREATMENT	RESULTS BEFORE	RESULTS AFTER	INCREASED OIL DURING 1ST 60 DAYS
1.	KANSAS	ARBUCKLE LIME	INITIAL TREAT	36 BOPD 874 BWPD	460 BOPD 500 BWPD	15,000 BBL
			RETREATMENT (22 months)	27 BOPD 883 BWPD	110 BOPD 540 BWPD	6,000 BBL
2.	KANSAS	ARBUCKLE LIME	INITIAL TREAT	19 BOPD 621 BWPD	69 BOPD 600 BWPD	6,000 BBL
			RETREATMENT (3-1/2 years)	4 BOPD 580 BWPD	120 BOPD 160 BWPD	4,200 BBL
3.	KANSAS	ARBUCKLE LIME	INITIAL TREAT	5 BOPD 570 BWPD	60 BOPD 500 BWPD	3,300 BBL
			RETREATMENT (3 years)	5 BOPD 550 BWPD	70 BOPD 230 BWPD	3,600 BBL

Table 4.—Polymer Water Control in Producing Wells in Indiana.

CASE 1. Sullivan County, Indiana. Pennsylvanian sand at depth of 590 feet. This new well had filled up overnight with 550 feet of fluid in hole. Operator was unable to bail hole.

TREATMENT: 120 barrels of polymer water-control chemicals at low rate and low pressure.

RESULTS: After 2 weeks—18 bopd, trace of water. After 4 months—5 bopd, trace of water.

CASE 2. Pike County, Indiana. Waltersburg sand at depth of 1,037 feet. Fracture treatment using 3,000 gallons broke into bottom water. Well was making trace of oil, 300 bwpd.

TREATMENT: 120 barrels of polymer water-control chemicals at low rate and low pressure.

RESULTS: 7 bopd, 23 bwpd.

CASE 3. Gibson County, Indiana. Hardinsburg sand at depth of 1,600 feet. Well was known to be near bottom water. Well gradually went from all oil to all water during a 2-year span. Well produced no oil and more water than could be pumped.

TREATMENT: 180 barrels of polymer water-control chemicals at low rate and low pressure.

RESULTS: 5 bopd, 10 bwpd.

one of the first multi-well jobs several years ago. While rates remained fairly constant, the average pressures were increased slightly. Although a significant production response was noted from producers in this pattern, the economics of this application would probably justify a treatment increase of 100 percent today. Nineteen producers in the response area produced an additional 187,000 barrels of oil during the 36-month period following the treatment.

Table 5.—Results of Sandstone Treatment on Injection Well in Garvin County, Oklahoma.

LOCATION: Garvin County, Oklahoma
FORMATION: Springer sand
PATTERN: Inverted nine spot
TREATMENT: 3,000 pounds of polymer
RESULTS: Offset producers for 15 months following treatment.

PRODUCER	OIL INCREASE (BBL)	WATER DECREASE (BBL)
1	11,400	26,100
2	10,500	34,700
3	6,100	21,800
4	3,500	23,200
5	4,500	20,800
6	4,100	65,900
TOTAL	49,900	216,300

Table 7 shows results of a multi-well treatment in a carbonate reservoir in Canada. One of the problems encountered in this field was directional permeability. A program of in-fill drilling was under consideration at the time polymer chemicals were tried for water control. Chemical injection caused a change in flow patterns to provide a total increase in oil production amounting to 180,000 barrels during the 28-month period following these treatments.

Table 6.—Polymer Water Control in Injection Well.

LOCATION:	Oklahoma
FORMATION:	Tatums Sandstone
DEPTH:	3,000 feet
NUMBER OF INJECTORS TREATED:	13
TREATMENT:	30,000 pounds of polymer (173,000 bbl)
TREATMENT TIME:	13 days

INJECTIVITY:	INJECTION PRESSURE, PSI	AVG. RATE BBL/DAY/ WELL
BEFORE TREATMENT	70	1,130
AFTER TREATMENT	250	1,100

RESULTS:
NUMBER OF PRODUCERS AFFECTED: 19
INCREMENTAL OIL (AFTER 36 MONTHS): 187,000 bbl

Table 7.—Polymer Water Control in Injection Well.

LOCATION:	Saskatchewan, Canada	
FORMATION:	Midale Limestone	
DEPTH:	4,000 feet	
NUMBER OF INJECTORS TREATED:	5	
TREATMENT:	8,000 pounds of polymer (35,000 bbl)	
TREATMENT TIME:	21 days	
INJECTIVITY:	INJECTION PRESSURE, PSI	AVG. RATE BBL/DAY/WELL
BEFORE TREATMENT	610	5400
AFTER TREATMENT	1,470	520
RESULTS:		
NUMBER OF PRODUCERS AFFECTED:	INCREMENTAL OIL	
(AFTER 28 MONTHS):	21	
	180,000 bbl	

These instances of water control at injection wells are examples of enhanced oil recovery. Without the changes made by the placement of polymer in these wells, production from responding producers would have continued to deteriorate rather than improve.

MOBILITY CONTROL

There should be a distinction made at this point between water control and mobility control. Water control must be an objective prior to mobility control. Mobility control is concerned with reservoir behavior rather than individual well performance. Polymer chemicals are used in a flooding operation to decrease the mobility of the injected fluid, thus improving the flood efficiency. The effects of polymer chemicals are reflected in several ways:

1. The effects of wide permeability distribution are reduced.
2. The displacement efficiency is improved.
3. The volumetric sweep efficiency is improved.

The volume of chemical injection required to effect such changes has to be larger than for individual-well water control.

Diluted concentrations of polyacrylamide polymer solutions can produce these favorable changes (Fig. 1). When a polymer solution's viscosity is measured directly in a standard laboratory viscometer, values are relatively proportional to the polymer concentration. Yet when the same solution flows through a microporous medium, such as a sandstone core, it will behave as though the viscosity were 10 or more times greater than has been determined instrumentally. This effect is most pronounced in concentrations of 100 to 1,000 ppm.

The apparent change in viscosity of the displacing medium in porous rock results in improved flooding efficiency (Fig. 2). The left curve in Figure 2 shows flooding performance of a conventional waterflood with a brine to oil mobility ratio of 12:1. The potential economic recovery of this flood appears to be in the range of 300 barrels per acre-foot. The right curve shows the effect of reducing this mobility ratio by a factor of six, to a ratio of 2:1. The potential recovery of a corresponding water-oil ratio is approximately 500 barrels per acre-foot.

An example of polymer-augmented waterflooding is shown in Figure 3. This pilot project took place in northern Oklahoma. The net zone was 30 feet of sandstone, and porosity was 17 percent. Nine injection wells were used in the five-spot pattern, enclosing four producers. A total of 72,000 pounds of polymer was injected

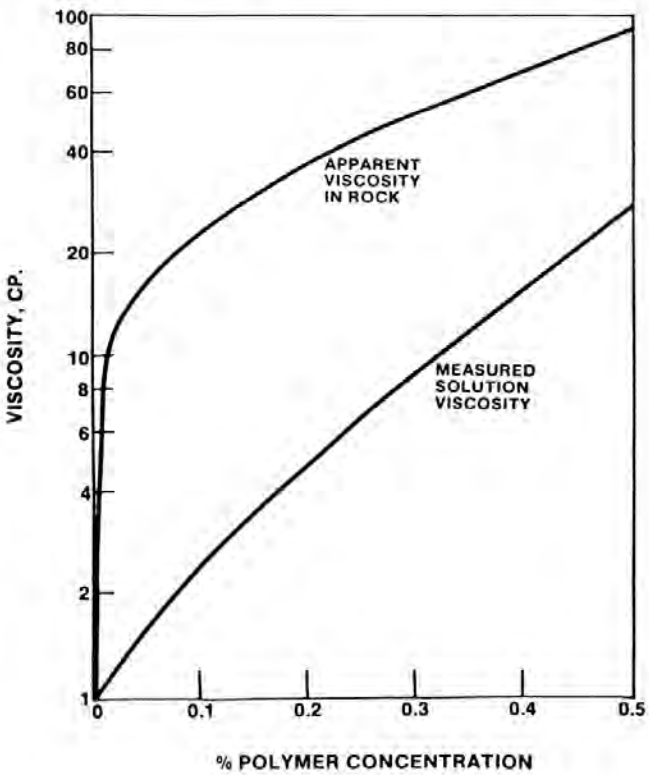

Figure 1. Graph showing resistance effect of polyacrylamide.

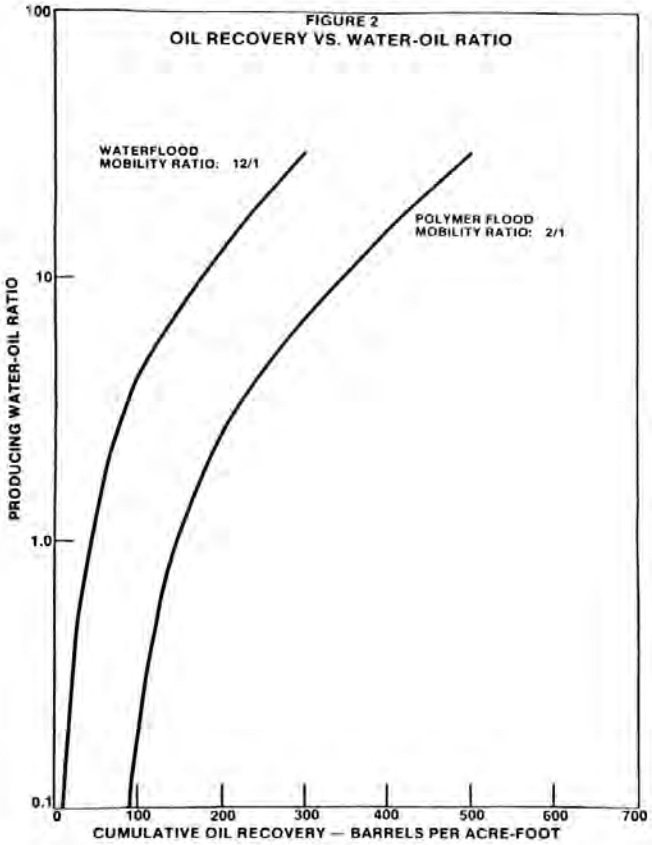

Figure 2. Graph comparing oil recovery and water-oil ratio.

during a period of 10 months. The oil-rate and water-oil ratio curves reflect the combined performances of the four producers. Incremental oil, amounting to 140,000 barrels, was credited to polymer flooding over a 2 1/2-year period. One reason this project is shown is that the oil was a good grade of crude having 3 cps viscosity; the flood should not have had a particularly adverse mobility ratio. However, the permeability variation was extremely adverse and contributed to the main cause of flooding deficiency. The polymer tended to reduce this variation. The timing of the project is also noteworthy. The polymer injection was initiated in a late stage of flooding life: a water-oil ratio of 27:1. Yet the production of 140,000 barrels of additional oil represents 4 percent of the original oil in place.

A similar project in northern Oklahoma showed even more dramatic results. Polymer was injected into the four-well pattern (Fig. 4); the four producers were in a line between the injectors. The project was initiated when the water-oil ratio was about 70:1, a point at which normal operations would have been considered uneconomical. As a result of injecting 84,500 pounds of polymer into these wells, 250,000 additional barrels of oil were produced. This volume was equivalent to 4.3 percent of the original oil in place. At this point most waterfloods have been plugged and abandoned.

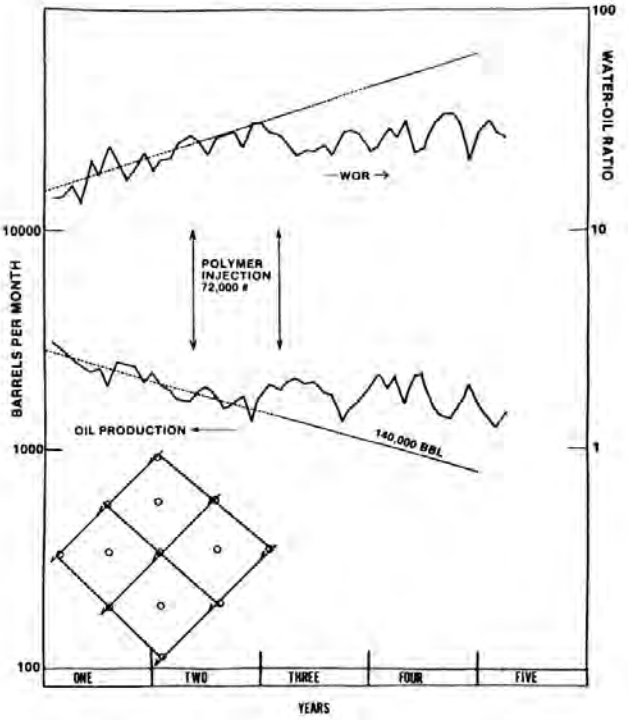

Figure 3. Diagram showing polymer pilot confined wells.

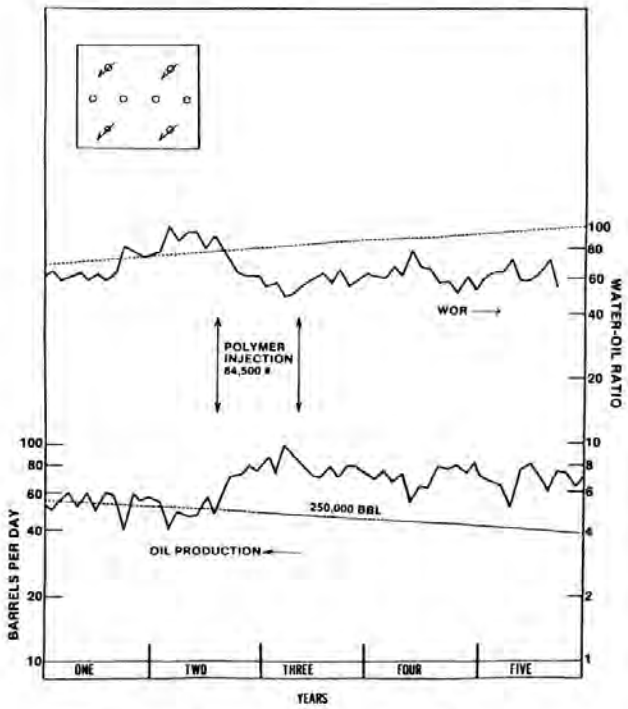

Figure 4. Diagram showing polymer pilot.

Design Parameters

Some average design parameters for a traditional polymer-augmented water-flood are shown in Table 8. The volume of the chemical slug will generally be be-

Table 8.—Average Parameters for Traditional Polymer Flood.

POLYMER SLUG: 20 to 50 percent pore volume

POLYMER CONCENTRATION: 200 to 1,000 ppm (0.07 to 0.35 lb/bbl)

POLYMER USE RATE (AT 20 PERCENT POROSITY): 310 to 775 baf (at 300 ppm): 33 to 81 lbs/af)

INCREMENTAL OIL OVER WATERFLOOD: 30 to 80 baf. Approximately 5 percent original oil in place. 1 bbl oil/1 lb. polymer

COST (CHEMICAL): $1.00 to $3.00/bbl incremental oil

tween 20 and 50 percent of the pore volume. The larger slugs of polymer injection are economically justified as crude prices escalate. Optimum concentration of the polymer will vary with the composition of the water, rock, and crude oil. Concentrations normally range between within 200 and 1,000 ppm. Conditions may favor the use of a tapered concentration over a constant use level during the chemical slug. For a formation with a porosity of 20 percent, the above range of slug size would vary from 310 to 775 baf. If a concentration of 300 ppm were used in the treatment, the polymer requirement for this range of slug size would vary from 33 to 81 pounds per acre-foot. Experience has shown that a properly conducted polymer flood of this magnitude could be expected to produce an additional 5 percent of the original oil in place. This amount of oil generally represents from 30 to 80 barrels per acre-foot. Such recovery results in a conservative rule of thumb: 1 pound of polymer will generate one barrel of additional oil. At current chemical costs, the average expense is between $1.00 and $3.00 per incremental barrel of oil.

ENHANCED OIL RECOVERY INCENTIVES

DOE encourages the oil operator to engage in acknowledged processes for enhanced oil recovery. DOE is using the crude oil price control program to offset certain enhanced oil recovery technique costs. This program permits a producer to recover 75 percent of certain costs by selling any of his controlled oil production at market price. The program permits self-certification of the process used in order to minimize delays in implementing a feasible EOR program. Due to the provisions of the program, these incentives are available only until the expiration of pricing controls, which is scheduled for October 1, 1981.

Provisions of the Windfall Profit Tax Act of 1980 also recognize the potential of enhanced oil recovery by including special incentives. Front-end incentive tertiary production is totally exempt from the tax, providing ownership of the property is 50 percent independent. A producer can earn an incremental tertiary production classification for tax purposes by initiation of an EOR process. The tax act permits self-certification of these projects. Incremental oil production for tax purposes is defined in the Act as production in excess of the property's bpcl, declined at 2 1/2 percent per month, or actual decline if greater. A producer's tax rate of 70 or 50 percent can be reduced in this manner to a minimum of 30 percent.

COAL LIQUEFACTION PROCESSES AND THE COAL LIQUEFACTION PROGRAM AT THE UNIVERSITY OF KENTUCKY INSTITUTE FOR MINING AND MINERALS RESEARCH

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ABSTRACT

There are several current direct coal liquefaction processes. The solvent-refined coal process (SRC-I) produces a clean, solid fuel by heating and adding hydrogen to a coal slurry, dissolving it, and then recovering it in a vacuum distillation column. The SRC-II process heats the slurry to a higher temperature than the SRC-I process and produces liquid hydrocarbons rather than solid solvent-refined coal. The H-Coal process uses a cobalt-molybdena-aluminum catalyst and an ebullating bed reactor to produce liquid fuels from coal. The Exxon Donor Solvent process (EDS) subjects the process solvent to catalytic hydrogenation prior to recycling.

Other coal liquefaction processes, called two-stage liquefaction, involve heating a coal slurry and placing it in a dissolver to produce a liquid in the first stage, and converting the liquid into products that resemble hydrocarbon fractions obtained from petroleum distillation by using a catalytic reactor in the second stage.

Indirect liquefaction processes include SASOL and M-Gas. SASOL, being used in South Africa, converts the gasification products, CO and H_2, to liquid hydrocarbons with the Fischer-Tropsch process. The M-Gas process, developed by Mobil, is based on the conversion of methanol to hydrocarbons using a zeolite catalyst.

The University of Kentucky Institute for Mining and Minerals Research (IMMR) is involved in several programs studying liquefaction. IMMR has collected several tons of samples and is subjecting them to standard coal analyses to determine the liquefaction characteristics of various Kentucky coals.

IMMR, Ashland Oil, and Air Products and Chemicals, Inc., cooperatively studied corrosion in the fractionation areas and vacuum towers of SRC-I and H-Coal commercial plants. The results have been used to make process design and materials selections for these plants.

A survey of the reactivity of Kentucky coals, a study of reactions occurring in the preheater in a reactor, and the evaluation of the reactivity and product slate obtained from two-stage liquefaction of Kentucky coals are underway or are being planned.

IMMR will also investigate the range of liquefaction under conditions that simulate the full process flow chart. Electron spectroscopy for chemical analysis (ESCA) showed that a methanation catalyst contained nickel in the metal and oxide forms as well as in a compound formed with the support.

IMMR experiments indicate that coal bottom ashes crushed to 100-mesh size are an economical alternative to diatomite as a filter aid in solid separation processes.

The products of a PDU run of Hydrocarbon Research, Inc., were analyzed in a joint effort with Ashland Oil. This effort required many of the methods developed by IMMR prior to the analysis.

Other analyses are directed toward waste disposal and potential environmental problems.

LIQUEFACTION PROCESSES

Direct Liquefaction

Liquefaction processes are usually classified as direct or indirect. Direct liquefaction involves heating the coal, usually in the presence of hydrogen and a process solvent, at high temperatures. The coal is first gasified to form carbon monoxide (CO) and hydrogen (H_2) which are then catalytically converted to a liquid product. The catalyst increases the reaction rate in order to carry out reactions that would be too slow without a catalyst.

Figure 1 is a simplified flow diagram of a solvent-refined coal process (SRC-I) (Lloyd, 1980). This process, in the simplest mode, is designed to produce a clean, solid fuel (i.e., a fuel lower in environmentally unac-

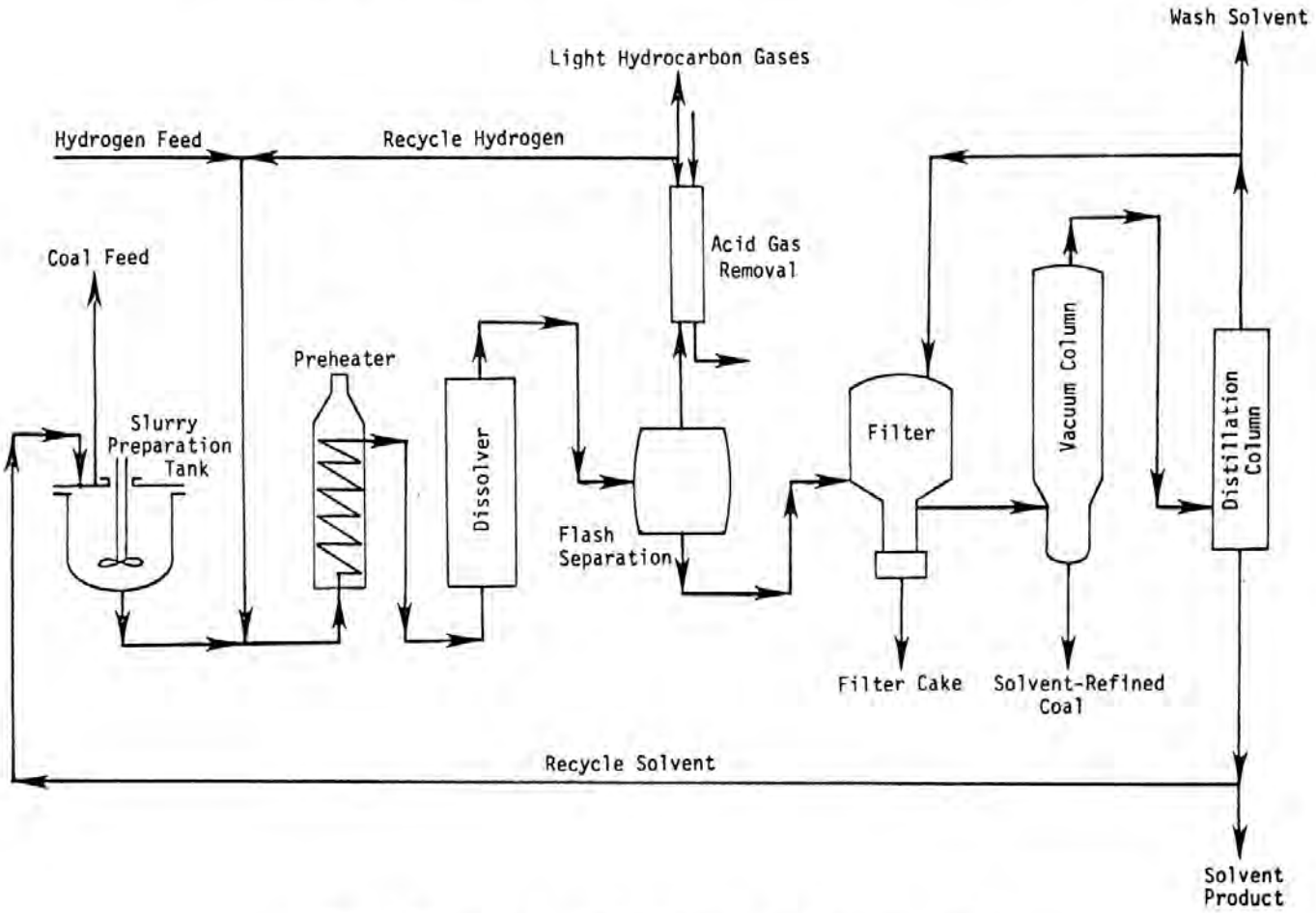


Figure 1. Simplified flow diagram of a solvent-refined coal process (SRC-I).

ceptable sulfur, nitrogen, and mineral matter than the feed coal).

The first step in the SRC-I process is the preparation of a coal-process solvent slurry containing about 40 percent coal. Hydrogen is added to the coal slurry before it enters a preheater, where it is heated to a temperature 100 to 300° F below the reaction temperature. From the preheater the slurry enters the dissolver, where it stays about 30 minutes until it is about 85 to 95 percent converted. The slurry is then placed in a flash evaporator, where the low-boiling naptha is removed from the higher boiling materials. The solvent-refined coal is recovered in the vacuum distillation column. Process and wash solvents are then recovered in the atmospheric distillation tower.

A small SRC-I demonstration plant is presently in operation at Wilsonville, Alabama, by Catalytic, Inc. A joint venture of Wheelabrator-Fry, Air Products, and Chemicals, Inc., is now in the design phase of a 6,000-ton-a-day plant. Construction of this plant is scheduled to begin in 1983 in Daviess County in western Kentucky.

The SRC-II process outlined in Figure 2 (Jackson and Schmid, 1979) differs from SRC-II in that higher boiling material is used to prepare the coal slurry. The high boiling material is recycled until it is converted to liquid products fuel oil and lower boiling petroleum fractions. SRC-II is designed to produce liquid hydrocarbons rather than the solid solvent-refined coal produced in the SRC-I process. A demonstration plant at Fort Lewis, Washington, is operated by Gulf Oil Corporation in the SRC-I and SRC-II modes.

The H-Coal process is designed to produce liquid fuels (Fig. 3) (Hoertz and Swan, 1979). The major differences between SRC-II and H-Coal are the use of a cobalt-molybdena-aluminum catalyst and an ebullating bed reactor (Fig. 4) (Hoertz and Swan, 1979). The ebullating bed is designed to prevent the mineral matter of the coal from being held up in the catalyst bed and plugging the reactor. The coal slurry is recycled through the reactor at a rate sufficient to provide agitation of the catalyst bed and carry the smaller mineral matter particles from the catalyst bed. A 6-ton-a-

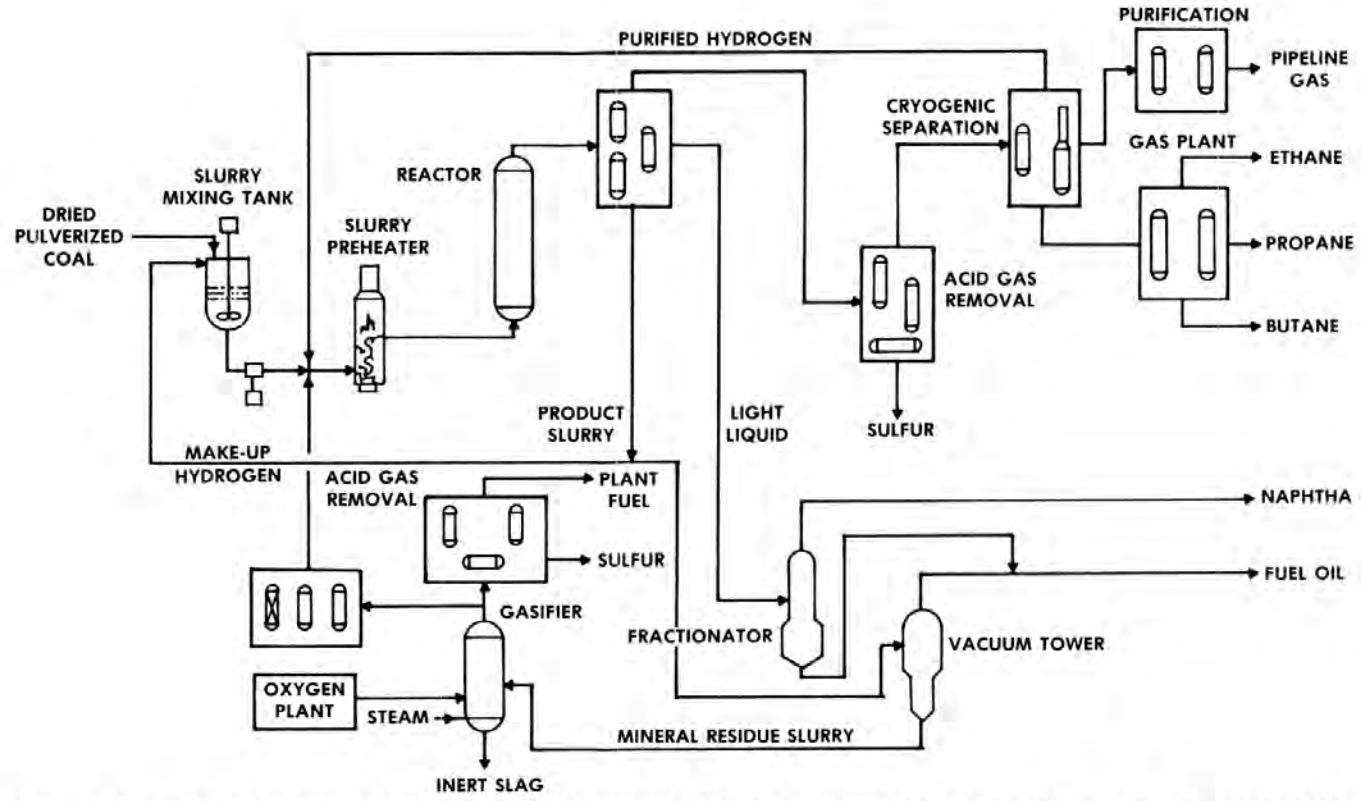


Figure 2. Simplified flow diagram of a solvent-refined coal process (SRC-II). From Jackson and Schmid (1979). Used with permission of the American Chemical Society.

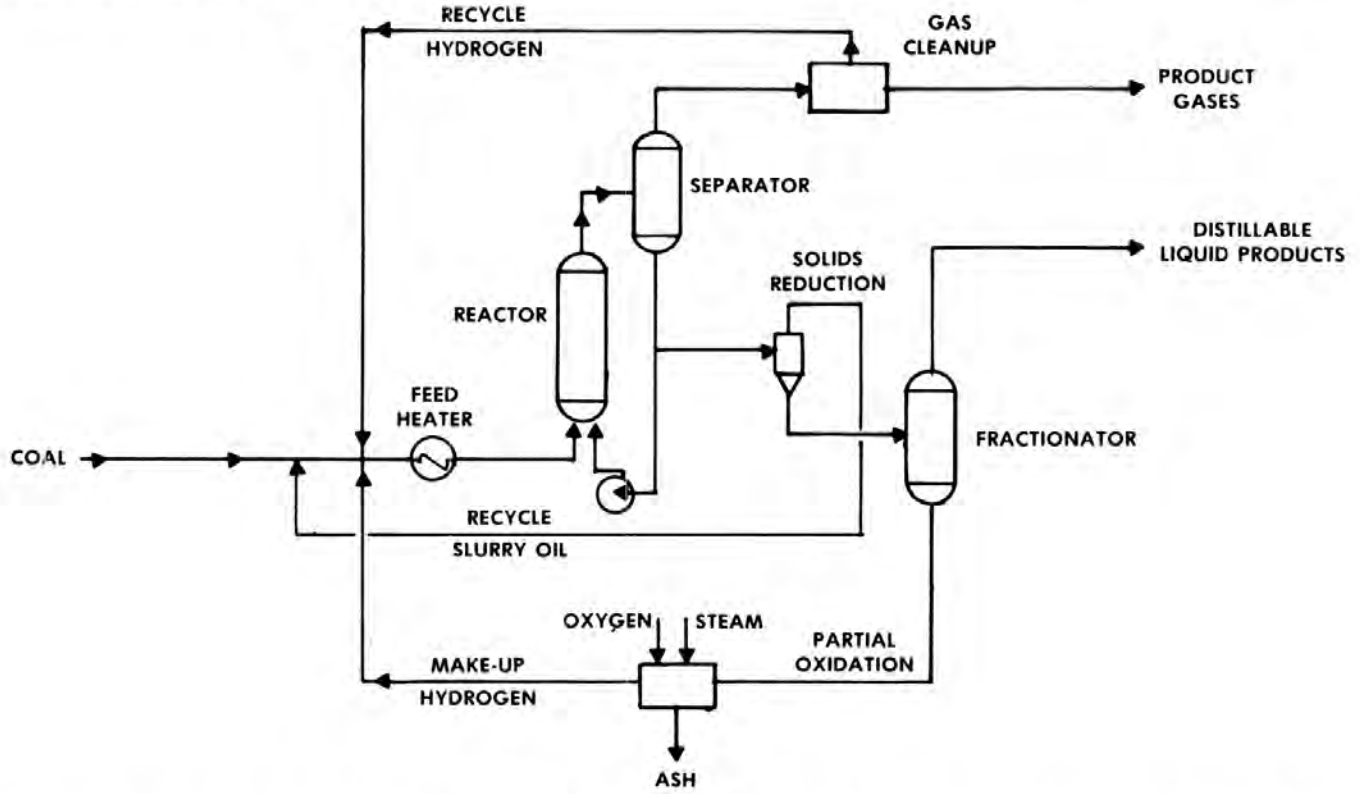


Figure 3. Simplified flow diagram of the H-coal process. From Hoertz and Swan (1979). Used with permission of the American Chemical Society.

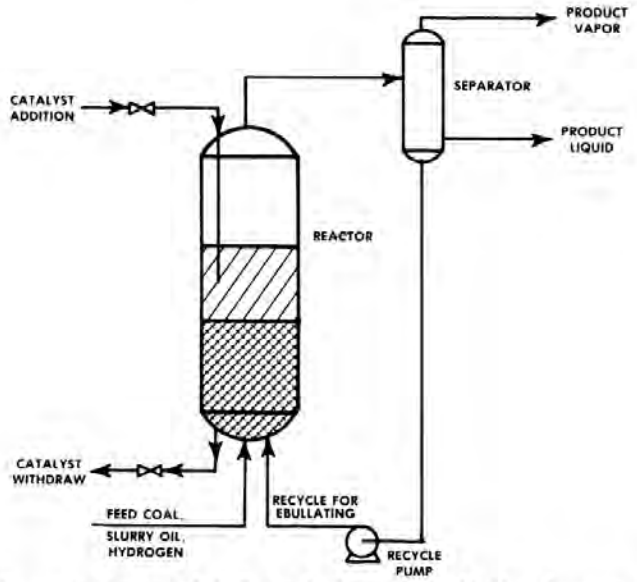


Figure 4. Diagram of ebullating bed reactor used in H-coal process. From Hoertz and Swan (1979). Used with permission of the American Chemical Society.

day H-Coal demonstration plant is now in operation at Catlettsburg, Kentucky. Ashland Oil Corporation is carrying out a feasibility study for the construction of a commercial plant in western Kentucky.

The Exxon Donor Solvent Process (EDS) (Fig. 5) (Epperly and Taunton, 1979) is similar to the SRC and H-Coal processes. Coal solution is carried out in the absence of a catalyst, as it is in the SRC process. However, in EDS the process solvent undergoes catalytic hydrogenation prior to recycling, and in this respect resembles the H-Coal process.

Recently, much attention has been given to two-stage liquefaction. In the first stage the coal slurry is heated and placed in a dissolver to produce a liquid. In the second stage a catalytic reactor converts the liquid products into products that resemble the hydrocarbon fractions obtained from petroleum distillation. Catalytic, Inc.'s, Wilsonville, Alabama, plant is currently being modified to accommodate two-stage liquefaction by the addition of an ebullating-bed catalytic reactor that hydrogenates solvent-refined coal to a liquid product.

Coal solution involves several consecutive reactions. One reaction could be:

coal---→preasphaltene---→asphaltenes---→oils.

The formation of preasphaltenes could be viewed as the primary reaction, but unless secondary reactions occur, the preasphaltenes, upon standing at room temperature, may form a solid that is less reactive than the original coal. Thus, it is desirable to convert these higher weight preasphaltenes into lower boiling, more stable hydrocarbon fractions. These secondary reactions take place in the second-stage catalytic reactor. Figure 6 illustrates the sequence of production (Maekawa and others, 1979). The asphaltene concentration reaches a maximum and then decreases with increasing reaction time; there is a corresponding increase in the oil products.

There are a number of other direct liquefaction processes, but those described are of major concern during the next few years. SRC-I and H-Coal are currently of prime importance.

Indirect Liquefaction

The SASOL indirect liquefaction process is the only process now operating on a commercial scale. When the units now under construction are operational, they will provide South Africa with nearly half of its current liquid fuel needs. The SASOL plant uses the Fischer-Tropsch process to convert the gasification products, CO and H_2, to liquid hydrocarbons. The gasification of coal produces a synthesis gas containing one part CO to 1.5 to 2.0 parts H_2. The following reactions take place:

$C + H_2O \rightarrow CO + H_2$

$C + 2H_2O \rightarrow CO_2 + H_2$

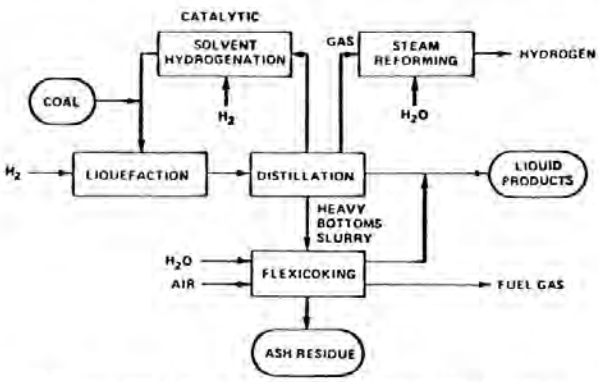


Figure 5. Simplified flow diagram of the Exxon Donor Solvent process (EDS). From Epperly and Taunton (1979). Used with permission of the American Chemical Society.

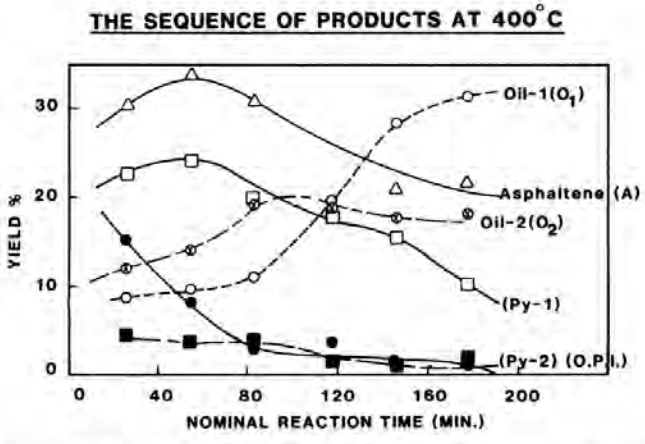


Figure 6. Graph showing sequence of products in two-stage liquefaction process. From Maekawa and others (1979). Used with permission of the American Chemical Society.

Typical product distribution, based on carbon number, is presented in Figure 7. Technical advances in the areas of gasification and reduction of high methane yield would make the Fischer-Tropsch synthesis a more attractive commercial process. The Texas Eastern Corporation is presently carrying out a feasibility study for the construction of a SASOL plant in western Kentucky.

Another indirect liquefaction process is based on the conversion of methanol to hydrocarbons using a zeolite catalyst introduced by Mobil Oil Corporation (M-Gas). The product yields from a 4-bbl-a-day pilot unit are presented in Table 1 (Morgan and others, 1980). Fifty-six percent of the methanol feed is lost as water. The superior fuel quality of the remaining 43 percent hydrocarbon yield must offset this high water weight loss if M-Gas is to be a viable process. A commercial M-Gas plant, based on methane rather than coal, is under construction in New Zealand.

Initial studies for an M-Gas plant in western Kentucky are being performed by W. R. Grace Co.

Hydrogen Requirements for Liquefaction

The data in Tables 2 and 3 (Lloyd and Davenport, 1980) show that the liquefaction of coal will require considerable amounts of hydrogen. They also show that crude has an advantage over coal since converting crude oil to gasoline requires little additional hydrogen.

Hydrogen consumption is a major consideration in the cost of the production of liquid fuels from coal. For a 25,000-ton-a-day H-Coal plant, hydrogen production accounts for about 10 percent of the total production cost. The capital investment in the equipment required for hydrogen production accounts for about 13 percent of the production cost (Clarence Johnson, personal commun.). Thus, the cost of hydrogen can account for

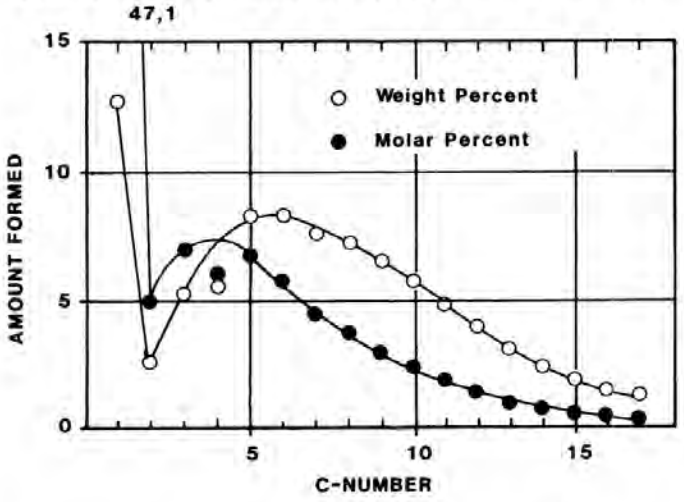


Figure 7. Graph showing distribution of product (by carbon number) from Fischer-Tropsch process.

Table 1.—Yields from Methanol in 4 B/D Fluid-Bed Pilot Unit. From Morgan and Others (1980).

Average bed temperature, **C**	413
Pressure, kPa	275
Space velocity (whsv)	1.0
Yields, Wt-% of Methanol Charged	
Methanol + ether	0.2
Hydrocarbons	43.5
Water	56.0
CO, CO_2	0.1
Coke, other	0.2
	100.0
Hydrocarbon Product, Wt-%	
Light gas	5.6
Propane	5.9
Propylene	5.0
I-butane	14.5
N-butane	1.7
Butenes	7.3
C_5 + gasoline	60.0
	100.0
Gasoline (Including Alkylate)	
(96 R + O, RVP = 9.0 psi)	88.0
LPG	6.4
Fuel gas	5.6
	100.0

Table 2.—Hydrogen/Carbon Ratios and Heating Values of Several Fuels. From Lloyd and Davenport (1980).

	H/C Ratio	Btu/Lb.
No. 2 fuel oil	1.86	19,600
No. 4 fuel oil	1.51	18,720
Australian shale oil	1.63	18,790
French shale oil	1.61	18,560
H-coal liquid, ASO	1.45	18,280
H-coal liquid, ASB	1.37	18,340
Coal (typical hvBb)	0.82	14,320

Table 3.—Hydrogen and Mineral Contents of Various Energy Sources.

	Hydrogen Content*	Mineral Content
Energy Source	Wt-%	Wt-%
Coal	2-6	6-18
Tar sands	10	85
Green River oil shale	10	80-95
Crude oil	12-14	0.02-0.1
Gasoline	16	—
Natural gas	24.7	—

*Moisture- and mineral-matter-free basis

20 to 25 percent of the cost of the liquid product. Table 4 shows that a reduction in light hydrocarbon formation would reduce the cost of liquid production (Clarence Johnson, personal commun.).

Table 4.—Hydrogen Consumption in Coal Liquefaction.

Liquid products	1.5%
90% oxygen removal	1.0%
90% sulfur removal	0.2%
60% nitrogen removal as NH_3	2.1%
Light hydrocarbons	2.1%
Wt-% H_2/bbl	5.0%

Cost of Synthetic Liquids

The 1979 selling price of synthetic fuels is shown in Table 5 (U. S. Senate, Subcommittee on Synthetic Fuels of the Committee on the Budget, 1979). The cost of petroleum and its competing synthetic fuels is shown in Figure 8 (U. S. Senate, Subcommittee on Synthetic Fuels of the Committee on the Budget, 1979). It should be pointed out that the cost of foreign oil is the range for much of the crude oil sold on contract. The price of crude on the spot market is frequently higher than this, and has frequently been in the $40/bbl range. If the cost of coal liquids is compared to the spot market price of foreign oil, the coal-derived liquids are more competitive than indicated in Figure 8.

IMMR LIQUEFACTION RESEARCH

University of Kentucky Institute for Mining and Minerals Research (IMMR) programs studying liquefaction fall into three broad areas: resource characterization, process studies, and product characterization. Some IMMR liquefaction programs in each area are briefly outlined.

Table 5.—Synthetic Fuels Comparative Economics (1979 $).

	Selling Price ($/Barrel)	Selling Price ($/MMBTU)*
SHALE OIL		
Underground mine/surface retort	22-26	3.70-4.30
Open pit mine/surface retort	24-26	4.00-4.30
Modified in situ	15-24	2.50-4.00
Combined MIS/surface	15-21	2.50-3.50
COAL LIQUEFACTION		
SRC-I	30-36	5.00-6.00
Hydroliquefaction	34-38	5.70-6.30
Indirect liquefaction	35-39	5.80-6.50
OIL SANDS		
Hot water extraction	26-33	4.30-5.50
In situ	31	5.20
COAL GASIFICATION		
First generation	35-46	5.80-7.70
Second generation	35-53	5.80-8.80

*Based on 6 million Btu per barrel

Resource Characterization

In the past year ton-size samples have been collected from several commercial mining operations. The history of these samples is well documented and the sam-

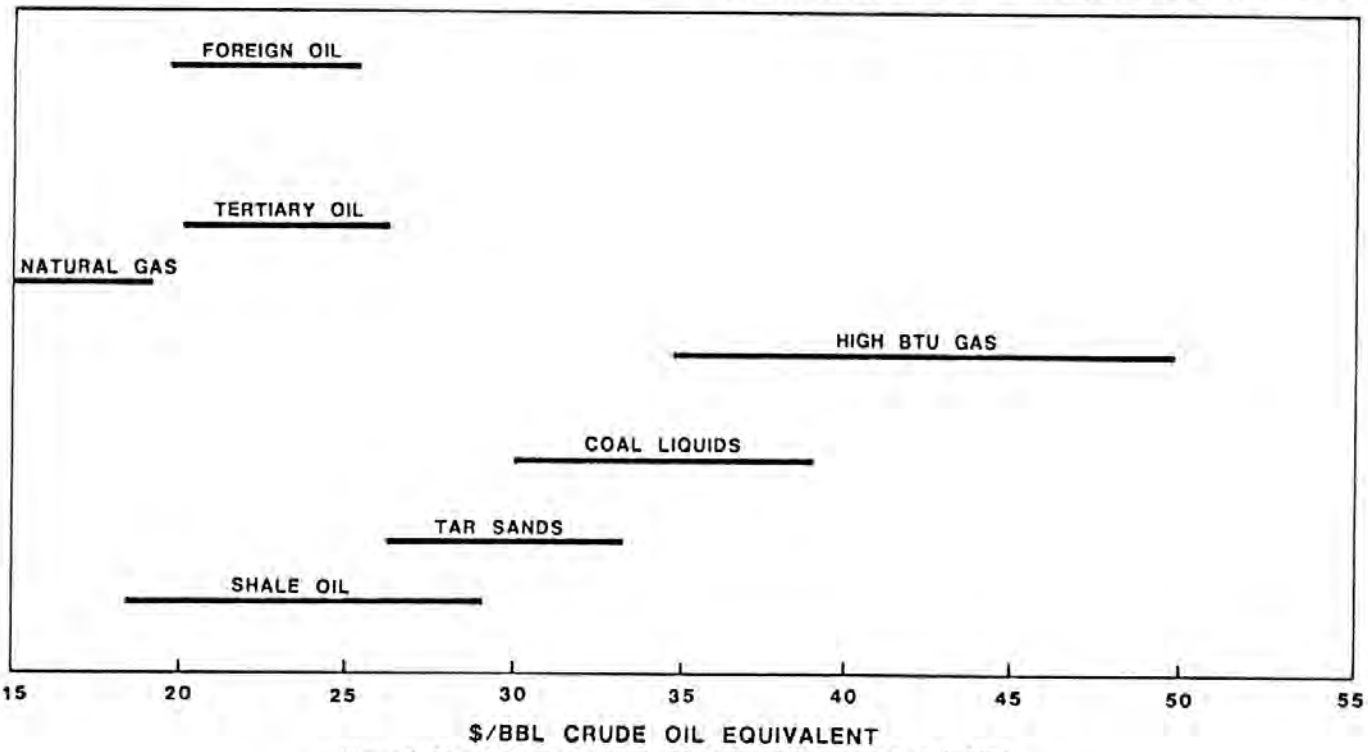


Figure 8. Graph showing costs of petroleum and synthetic fuels in 1979.

ples are collected under known, controlled conditions. The samples are collected in sufficient quantities for analysis and liquefaction studies. Samples of the collected coals have been provided to companies that are developing liquefaction processes.

The samples collected from the commercial mines will include run-of-the-mine samples, washed samples (if available), and at least three channel samples. The samples will undergo the usual coal analyses, such as ultimate, proximate, ash, and trace element. The samples will also be characterized by detailed petrographic analysis.

Portions of the collected samples will be retained. Should subsequent liquefaction studies reveal the need for further analytical data, IMMR will be able to make a survey of samples representative of a large fraction of the western Kentucky commercial production without the delay of sample collection.

A study is underway to identify coal preparation facilities in western Kentucky. Samples will be collected from several preparation plants in several phases of preparation. The liquefaction characteristics of these coal fractions will be evaluated to learn how coal preparation influences the liquefaction process. Since the present preparation facilities were not designed to produce coal for liquefaction, a program will be in itiated to evaluate other coal preparation schemes and the impact they will have on the liquefaction process.

The catalyst used in some liquefaction processes is expensive and increases the price of a gallon of liquid fuel. A program is underway to evaluate a number of minerals that occur near proposed liquefaction plants for catalytic activity. If this program is successful, a relatively cheap mineral could replace the more expensive catalysts presently in use.

Process Studies

Significant corrosion in the fractionation area and vacuum tower have been encountered at the SRC plants at Wilsonville, Alabama, and Fort Lewis, Washington. Corrosion rates exceeding 1,000 mils per year were reported in some instances. The severity of the problem has required relining, retraying, or replacing columns. Adding sodium carbonate to the Wilsonville coal feed reduced corrosion to manageable levels. The immediate cause of the observed deterioration was not evident because of the numerous parameters involved. The corrosion rates encountered at a demonstration plant while processing a high- and a low-chlorine Kentucky coal are shown in Figure 9. The 200 to 300 mils/year corrosive rate of stainless steel encountered with the high-chloride coal is far too high for a commercial operation.

IMMR, Ashland Oil, Inc., and Air Products and Chemicals, Inc., carried out a cooperative research program on corrosion. Work completed to date helped define a corrosion mechanism. The results from this study have been used to make process design and materials selection for the SRC-I and H-Coal commercial plants. A synopsis of the work follows.

The liquid used in the corrosion experiments was collected at the Wilsonville, Alabama, SRC-I demonstration plant from the T-105 atmospheric distillation tower tray 9 bypass. The sample was collected July 24, 1979, when sodium carbonate was being added to the coal feed at the maximum rate of 40 pounds of sodium carbonate for each 2 tons of coal. A Kentucky No. 9 coal was used as the plant feed. The liquid contained less than 10 ppm total chloride. In the first set of corrosion experiments coupons of 304L stainless steel and 1050 carbon steel were immersed into 500 ml of tray 9 liquid and heated at 220° C for consecutive time intervals. This testing temperature is representative of the temperature of tray 9, which was located near the area of maximum corrosion in the column. Average corrosion rates for those time intervals, as calculated from weight-loss measurements, are shown in Figure 10 (Johnson and others, 1980). Under these conditions the corrosion rate is greater for the carbon steel, but the rate for both steels is low compared to the high rates observed at Wilsonville during the period prior to the sodium carbonate addition. The rate for both steels declines with time. The corrosion rates observed during the first 20 hours represent the effect of up to 50 percent phenols and other corroding species present in the as-received liquid. It is clear that those species, by themselves, are not active enough to produce the dramatic effects observed during the plant incidents.

After the first 20 hours, 1,000 ppm ammonium chloride and 664 ppm chloride were added to the tray 9 liquid. The corrosion rates with ammonium chloride present were at least a factor of 10 greater than in the absence of ammonium chloride. The corrosion rate, in the presence of chloride, decreased with cumulative time of immersion. The results shown in Figure 11 clearly demonstrate that ammonium chloride enhances the corrosion rate and that the corrosion rate decreases with time.

Other similar corrosion experiments have been performed involving variations in the liquid medium. Figure 11 summarizes corrosion rates for the first 5 hours of exposure of 304L stainless steel and 1050 carbon steel coupons to tray 9 liquid, as-received and with various additives. Figures 11-A and -B show the corrosion rate using the as-received liquid and the liquid with 1,000 ppm ammonium chloride added. Figure 11-C shows that adding 970 ppm ammonium carbonate

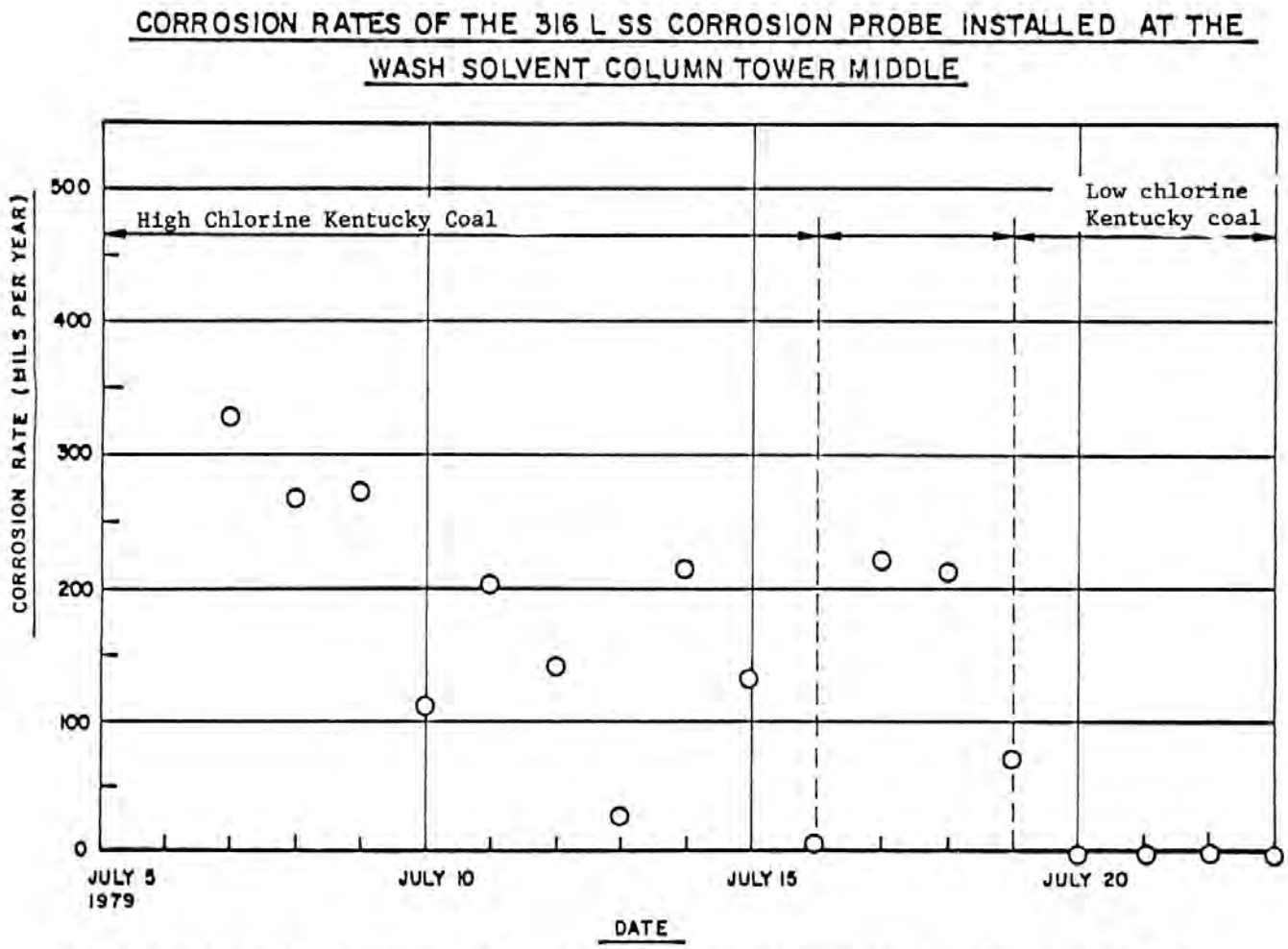


Figure 9. Corrosion rates at SRC demonstration plant at Wilsonville, Alabama, processing high- and low-chlorine Kentucky coal.

and 365 ppm NH_4+ does not cause an increase in the corrosion rate over that of the as-received tray 9 liquid. Since the results of the ammonium carbonate experiment are equal to or slightly greater than the results of the experiment with added ammonium chloride, it appears that the ammonium ion and ammonia provide little, if any, enhancement in the corrosion rate of the as-received material. Adding 1,420 ppm ammonium thiocynate to the tray 9 liquid containing ammonium carbonate (Figure 11-D) did not cause a significant increase in the corrosion rate. The carbon steel showed a slight gain in weight.

The experiments represented by Figures 11-E-H were carried out with a fraction of the tray 9 liquid. Phenols were removed from the as-received tray 9 liquid. The corrosion rates of the carbon and stainless steel coupons in the oil fraction were essentially the same as the low rates obtained with the as-received tray 9 liquid. This fraction is referred to as "oil," even though it contains some nitrogen compounds. Adding 970 ppm ammonium carbonate to the oil fraction did not alter the corrosion rates. Likewise, adding 1,000 ppm ammonium chloride to the oil layer caused an insignificant increase in the corrosion rates. However, when the phenol fraction was added to the oil fraction containing the 970 ppm ammonium carbonate and 1,000 ppm ammonium chloride, a high corrosion rate was obtained. The reason the corrosion rate for this reconstructed tray 9 liquid (Fig. 11-H) is slightly higher than the corrosion rate for the tray 9 liquid containing ammonium chloride (Fig. 11-B) may be traces of water remaining after the separation. However, other factors, including experimental scatter, may easily account for the difference. Figures 11-E through 11-H clearly demonstrate the synergism exhibited by the phenol and chloride components. The high corrosion rates obtained in liquid H show that the carbonate ion does not inhibit corrosion and that the sodium carbonate added to the feed coal does not suppress corrosion by supplying carbonate ions to the tray 9 liquid.

Figure 12 shows that water-soluble chloride accumulates in the atmospheric distillation tower (Davis and others, 1980). The corrosion rates, measured during the time interval in Table 6 (Pat Barnett, personal

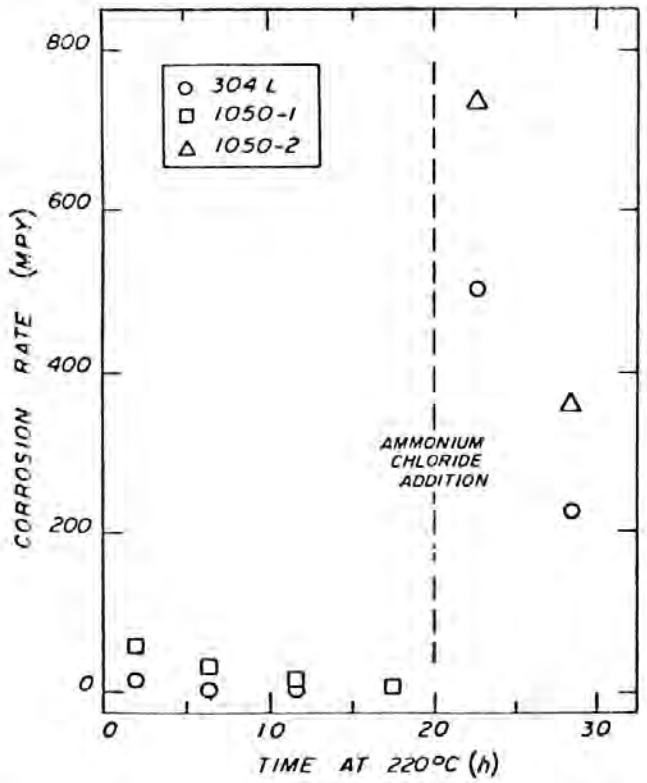
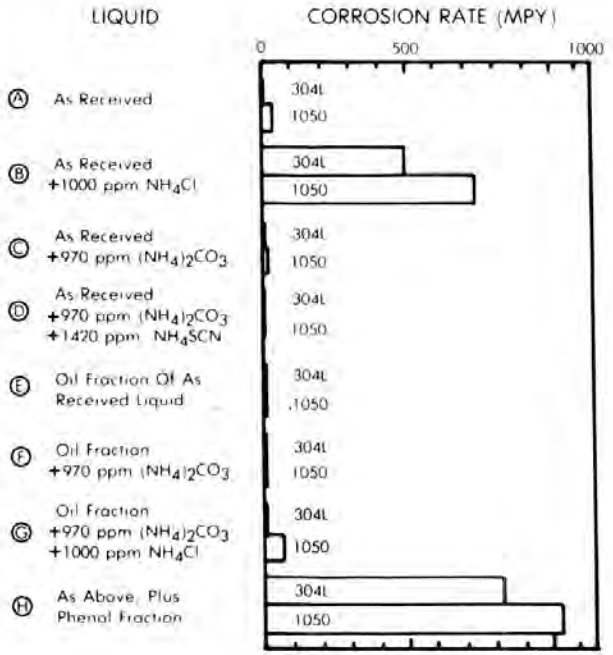


Figure 10. Corrosion rates of 304L stainless steel and 1050 carbon steel coupons as a function of the time of exposure to tray 9 liquids at Wilsonville, Alabama, demonstration plant. As-received liquids were used from 0 to 20 hours; 1,000 ppm NH_4Cl was added after 20 hours, using a fresh 1050 coupon.



Corrosion rates (averaged for the first five hours of exposure at 220 C) of 304L stainless steel and 1050 carbon steel coupons, exposed to tray 9 liquids. The asterisk * indicates the only case of (slight) coupon weight gain. In F and G, the ppm levels are calculated using the weight of the combined oil and phenol fractions.

Figure 11. Corrosion rates of 304L stainless steel and 1050 carbon steel coupons exposed to tray 9 liquids at Wilsonville, Alabama, demonstration plant. The asterisk indicates the only case of coupon weight gain. Levels of liquids F and G calculated using weight of combined oil and phenol fractions.

commun.), were high when the water-soluble chloride was measured.

The distillation tower is diagrammed in Figure 13. The chloride in the bottom of the tower is higher than in the incoming feed; the chloride concentration builds up in the bottom of the tower. The volatile chloride should readily distill from the top of the tower. However, the high phenol content of the liquid in the tower increases the solubility of the volatile chloride so that it does not distill from the tower. Rather, the chloride concentration builds up at some point in the lower part of the tower; the exact point will depend on process variables such as the temperature and liquid flow.

The soluble chloride path through the Wilsonville, Alabama, SRC-I plant has been deduced. This has resulted in further sampling and experiments at Wilsonville.

Chloride corrosion has received widespread attention. Unfortunately, the only high-chloride coals processed thus far in demonstration plants have been from western Kentucky. Retsch and Kohn (1980) suggested, in a recent article in "Chemical Engineering," that a simple solution to the problem of chloride corrosion might be to get the coal from a different location:

> . . . Exxon's early autoclave tests showed strong indications that sulfur compounds were the dominate corrosive species for typical donor-solvent coal liquids, according to Jerry Sorell, an engineering associate with Exxon Research and Engineering Co. (Florham Park, N. J.). In contrast, chloride-corrosion cracking may be a problem in SRC processing—where high-chloride-content Kentucky coals are being used.
>
> Yet, troublesome problems are sometimes easily solved. South Africa's SASOL is reputed to have solved a stubborn corrosion problem simply by switching the type of coal feed it used—a matter of getting feed from a different mine.

While the data in Table 7 make it clear that low-chlorine coals are readily available in western Kentucky (Gerald Thomas, personal commun.), it appears that eventually high-chlorine coal must be processed if coal liquefaction is to provide a significant portion of United States liquid fuels.

A survey of the reactivity of Kentucky coals is underway. The data in Figure 14 were obtained in a microclave reactor capable of rapid heat-up and cool-down that was designed at IMMR (Mori and Davis, 1980). The results demonstrate that a high conversion is obtained for short reaction times and that secondary reactions actually cause an apparent lower conversion at longer reaction times. There is a difference between

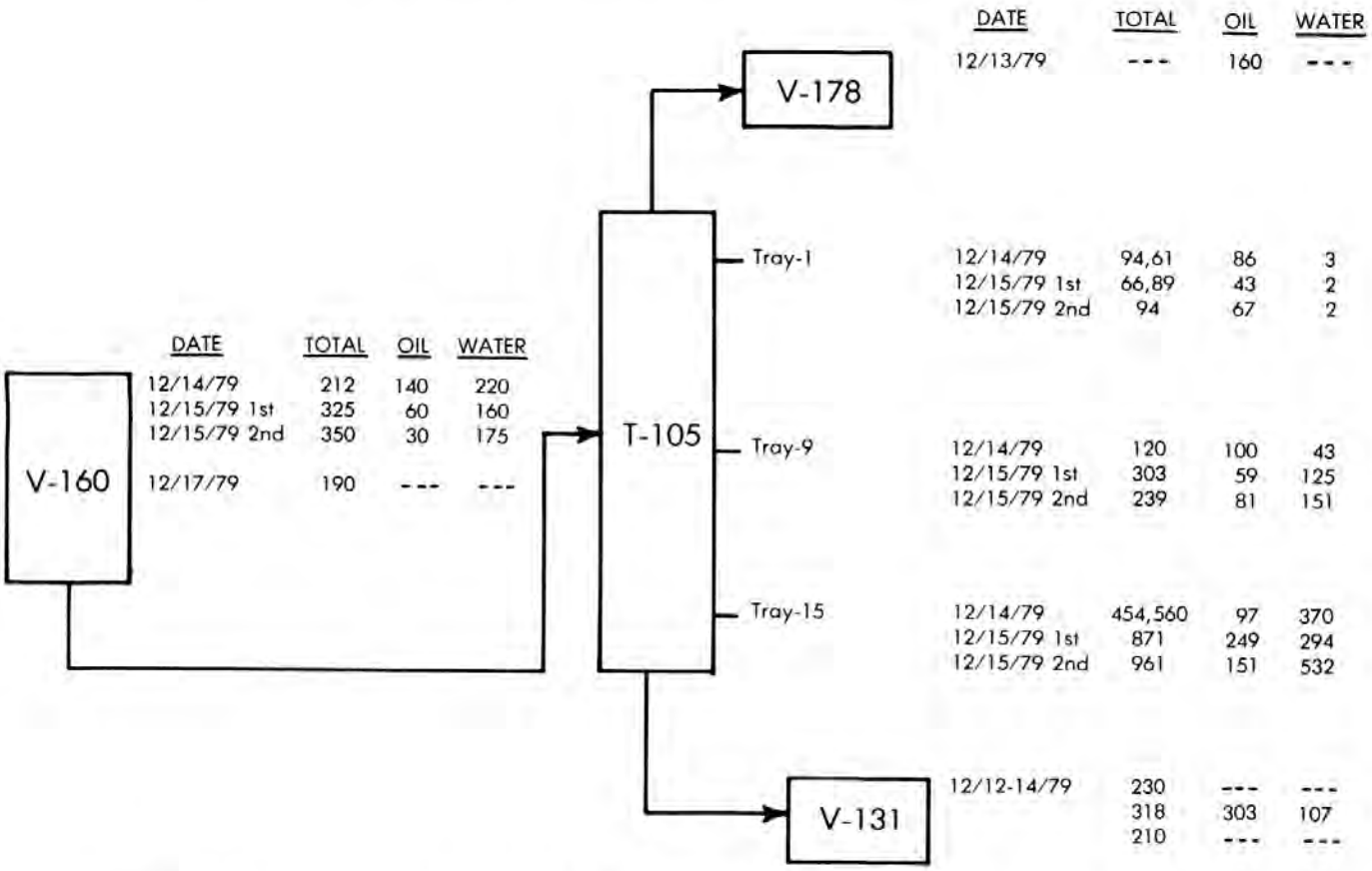


Figure 12. Graph showing chloride distribution in process stream around the T-105 atmospheric distillation column.

the catalyzed conversion and the reaction in the absence of a catalyst. The reactions occurring in the preheater will be studied in a reactor under construction at IMMR. This reactor, in combination with a stirred tank catalytic reactor that is near completion, will allow IMMR to evaluate the reactivity and product slate obtained from two-stage liquefaction of Kentucky coals. A 2-inch reactor process demonstration unit is under construction by Xytel Corporation for IMMR; this 10 kg/hour unit will enable IMMR to investigate the range of li quefaction processes under conditions that simulate the full process flow chart.

IMMR has a number of instruments that permit characterization of the outermost surface layers of materials. These instruments find many applications in areas such as catalyst and corrosion studies. One of these instruments, the scanning electron microscope (SEM) has potential for determining molybdena distribution in a hydrotreating catalyst. Molybdena is added to an alumina pellet in such a way that the molybdena is concentrated at the surface of the pellet. This concentration profile may be desirable since it may overcome some of the problems associated with diffusion of large coal molecules into the interior of the pellet. The SEM cross-sectional views of the pellet in Figures 15 and 16 clearly show the uniform distribution of aluminum in the alumina support and the concentration of molybdenum on the exterior of the pellet. The brighter area represents the higher concentration (*Larry Rice, personal commun.*). This distribution persists after the catalyst has been used for a short coal run. In many cases, similar concentration profiles can be recorded for the distribution of catalyst poisons in a used catalyst. These and similar instrumental techniques are used to obtain concentration profiles in corrosion scales. The element-depth profile in Figure 17 was obtained for a corrosion scale from the distillation tower from the Wilsonville, Alabama, SRC demonstration plant using electron spectroscopy for chemical analysis (ESCA) (Richard Shalvoy, personal commun.). ESCA is especially valuable since the chemical valence of the surface element may be determined by this technique. This technique has made it possible to show that a methanation catalyst, supplied by United Catalysts of Louisville, Kentucky, contained nickel in the metal and oxide forms as well as in a compound formed with the support.

For many coal liquefaction processes, precoat pressure filtration has been demonstrated to be an effective technique for separating ash-forming materials and un-

Table 6.—Plant Feed Parameters and T-105 Corrosion Rates During Periods of Sample Collections.

Date	Type of Coal Being Fed	Na_2CO_3 Added, lb/2 Tons Coal	Chlorine in Coal, %	Corrosion Rate* (MPY) Measured at Tray No. 9	Tray No. 15
7/24/79	Ky. No. 9 (Lafayette)	40	0.25	<1	<1
12/12/79	Ky. No. 9 (Lafayette)	10	0.18	9	27
12/13/79	Ky. No. 9 (Lafayette)	10	0.18	37	120
12/14/79	Ky. No. 9 (Lafayette)	10	0.18	37	186
12/15/79	Ky. No. 9 (Lafayette)	15	0.18	93	436
12/16/79	Ky. No. 9 (Lafayette)	15	0.18	205	321
12/17/79	Ky. No. 9 (Lafayette)	15	0.18	130	204
12/18/79	Ky. No. 9	15	0.18	56	77

*Corrosion rates of 321 ss. Corrosometer (c) probe wire. Rates correspond to the periods ending at 0700 hrs. of the date indicated.

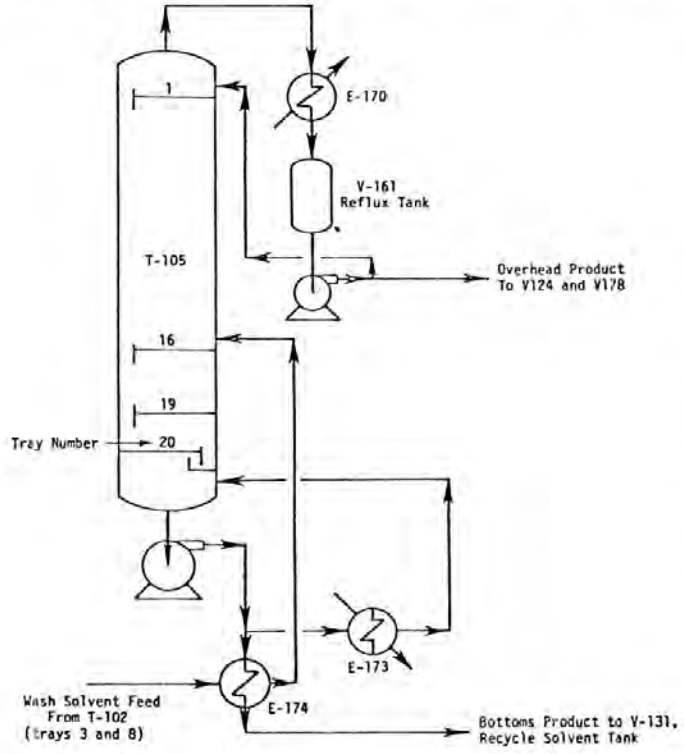


Figure 13. Diagram of T-105 atmospheric distillation chamber.

Table 7.—Chloride Content of Some Kentucky Coals.

KCERL Number	Coal Seam	County	Chloride
7237	11	Webster	0.18
7239	11	Webster	0.18
7242	4	Butler	0.02
7245	9	Muhlenberg	0.08
7246	9	Muhlenberg	0.11
7244	11	Muhlenberg	0.05
7248	9	Muhlenberg	0.04
7253	9	Henderson	0.05
7224	9	Hopkins	0.03
7227	14	Hopkins	0.02
7229	4	Hopkins	0.03
7232	11	Union	0.04
7235	9	Union	0.14
7222	11	Hopkins	0.03
7122	12	Hopkins	0.03
7124	14	Hopkins	0.02

converted coal from the very viscous liquefied coal. Precoating the filter medium is necessary because the large amount of submicron-size particles could easily block the pores of the filter medium. Currently, diato-

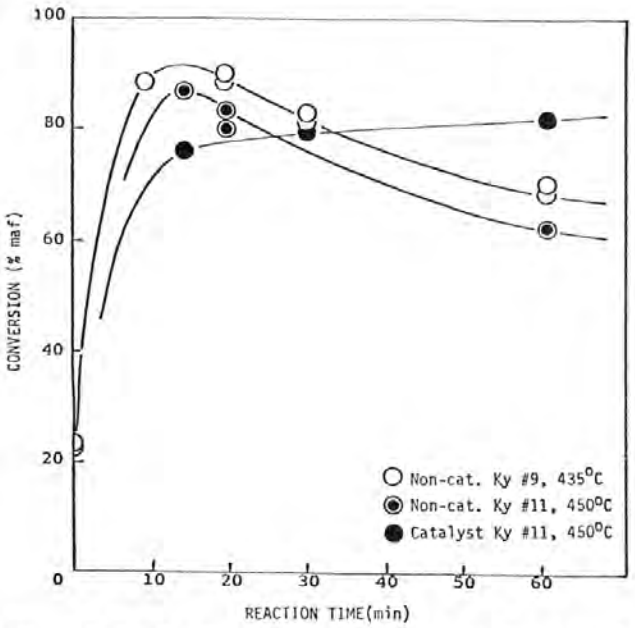


Figure 14. Reaction time and conversion of various Kentucky coals.

maceous-type filter aids are used as precoat materials. Although an adequate supply of diatomite poses no major difficulty for the filter aid requirement for a major synthetic fuel facility, its relatively high price will render precoat pressure filtration in coal liquefaction unattractive. If coal bottom ash can be used effectively as a filter aid, the economics of precoat pressure filtration would be more attractive.

Experimental work carried out at IMMR (Shou and others, 1979) indicates that coal bottom ashes that are simply crushed to about 100-mesh size can be used as an economical filter aid in a coal liquefaction solid separation process. Experimental results show that precoat pressure filtration using bottom ash precoat yields filtrate containing ash less than 0.1 weight percent and sulfur less than 0.7 weight percent. These low ash and sulfur contents will meet the Environmental Protection Agency's combustion emission standards. However, precoat made of extremely fine and narrow size range ash particles is unable to give an effective separation. Filtration rates generated from ash precoat filtration are comparable to those rates obtained using diatomite precoat. The study demonstrated that coal bottom ash is an excellent substitute for traditional diatomaceous filter aid. By utilizing coal bottom ash as a filter aid, not only is precoat filtration process economy significantly improved, but also there will be no foreign material to contaminate the filtration products. Filter cake may be used as a supplemental solid fuel, and ash may be recovered for recycling.

Product Analysis

PDU run 9 was carried out by Hydrocarbon Research, Inc. (HRI), using Kentucky No. 11 coal. This run was

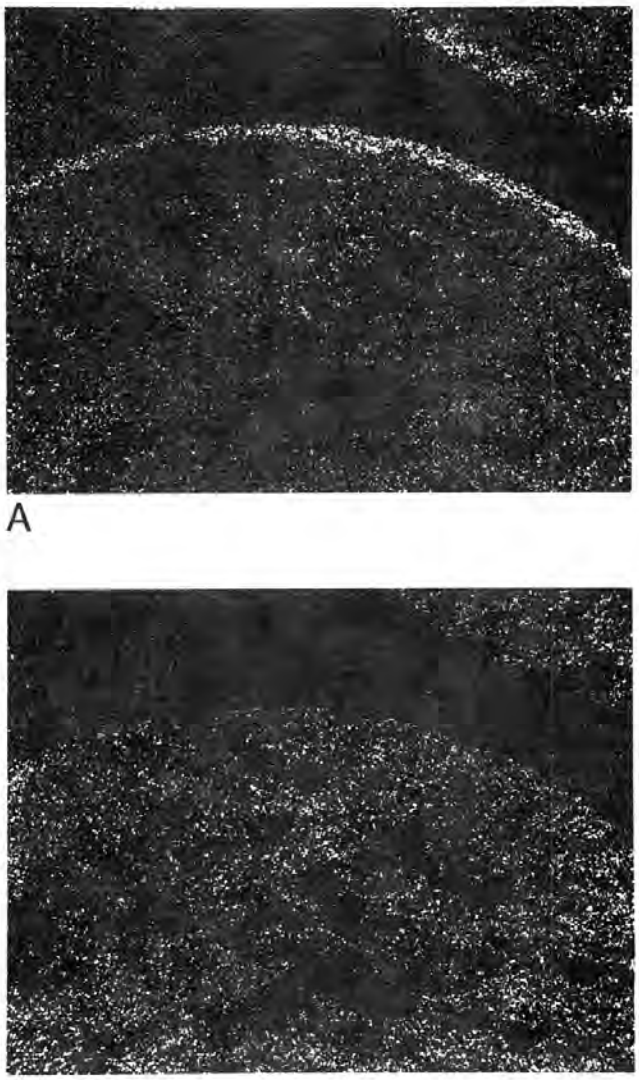


Figure 15. Cross-sectional views of alumina pellet with molybdena concentrated on surface, using scanning electron microscope. (A) Molybdena. (B) Aluminum.

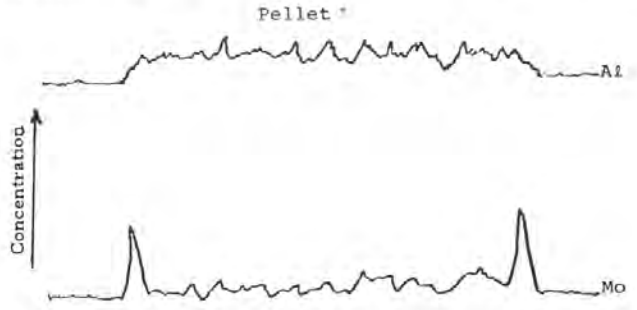


Figure 16. Profile showing concentration of aluminum and molybdenum in molybdena-coated alumina pellet.

carried out in the HRI pilot plant to simulate commercial H-Coal operation with a Kentucky coal. The products from this PDU run were analyzed in a joint undertaking by Ashland Oil, Inc., and IMMR. This effort

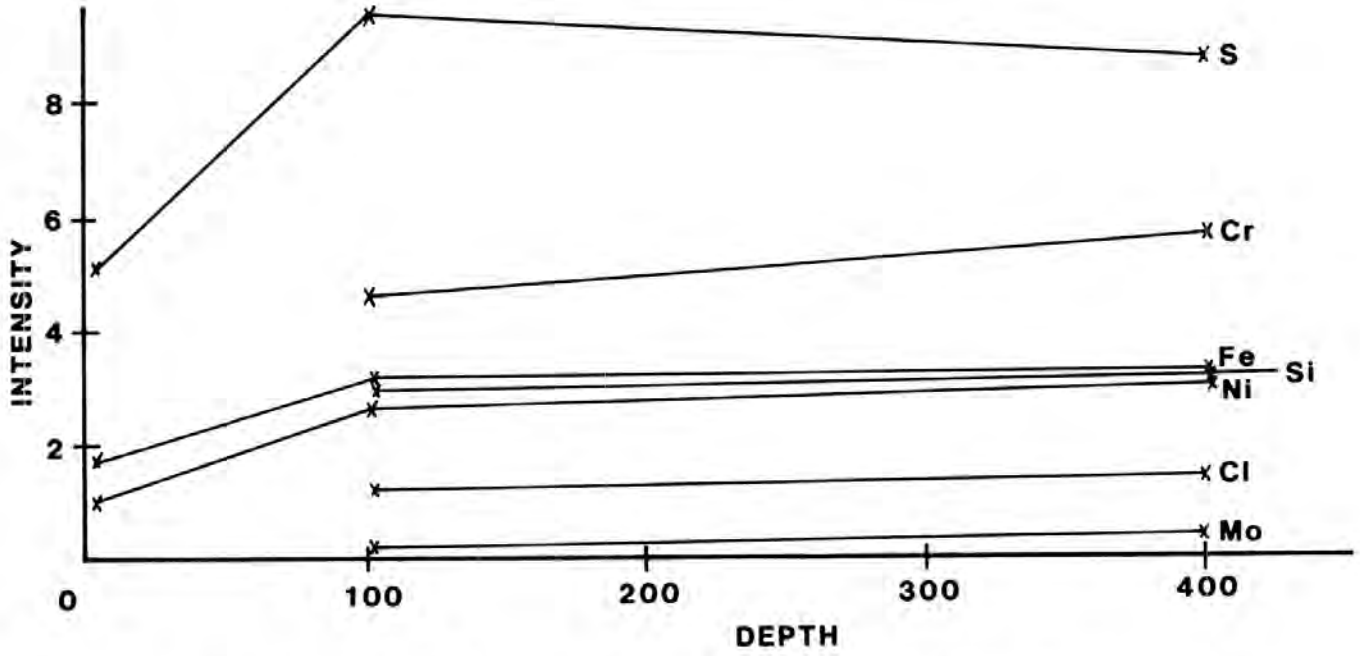


Figure 17. Depth concentration profile of elements in the corrosion scale from Wilsonville, Alabama, T-105 distillation tower.

required many of the methods developed by IMMR prior to the analysis.

Other analyses are directed toward a variety of liquefaction problem areas, especially waste disposal and potential environmental problems.

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CORRELATION OF THE DEVONIAN-MISSISSIPPIAN BLACK SHALE IN THE APPALACHIAN AND EASTERN INTERIOR BASINS IN KENTUCKY

John G. Beard
and
Roy C. Kepferle

ABSTRACT

Although geographic distribution and thickness of the Devonian-Mississipian black shale in Kentucky have been well researched, the internal character has not. Using geophysical logs, cores, and lithostratigraphy, the Devonian-Mississippian black shale in the Appalachian and Eastern Interior Basins in Kentucky are correlated.

INTRODUCTION

Surface exposures of Devonian and Mississippian black shale in central Kentucky cover about 540,000 acres. The horseshoe-shaped outcrop belt begins in Ohio, extends southerly into northeastern Kentucky at the Ohio River in Lewis County; curves southwesterly to Lincoln County, westerly through Marion County, and northwesterly to Jefferson County; and extends northerly back across the Ohio River into Indiana (Fig. 1).

The geographic distribution and thickness of the black shale are well researched (Schwalb and Potter, 1978; Potter, 1978; Schwalb and Norris, 1978; Fulton, 1979), but the research concerning the shale's internal character is not as complete. The internal stratigraphy of the black shale east of the Cincinnati Arch has been extensively documented, but the relationship of this section with the Cumberland Saddle and the Eastern Interior Basin to the west has not been defined. In addition, geophysical logging in the subsurface of western Kentucky revealed recognizable units that have not yet been related to the surface section.

Careful study of cores taken by the Kentucky Geological Survey from the black shale sequence in five key areas on and west of the Cincinnati Arch, and associated surface exposures, has led to revision of previously held stratigraphic concepts. The chief evidence for revision is the presence of the alga(?) *Foerstia (Protosalvinia)* in the Cumberland Saddle and on the west side of the arch.

PREVIOUS WORK

David Dale Owen was the first to describe the black shale in Kentucky in 1856 (p. 91); he called it the "Black Lingula shale." He very accurately located the geographic position of the horseshoe-shaped outcrop (Fig. 1) and studied it in some detail for associated coal deposits, concluding that there were none. He did not assign an age to the Kentucky deposits, but concluded the black shale in Indiana was sub-Carboniferous (Lineback, 1970, p. 4).

In Kentucky the shale has various names. On the west side of the Cincinnati Arch and in the subsurface of the Eastern Interior Basin it is called the New Albany Shale, after Borden, who first called it the "New Albany black shale" (1874, p. 150, 152, 158, 172). In south-central Kentucky it is called the Chattanooga Shale (Hayes, 1891, p. 143), and east of the Cincinnati Arch it is called the Ohio Shale (Andrews, 1870, p. 62) and Sunbury Shale (Hicks, 1878, p. 216-220). The general geographical divisions within the New Albany Shale were recognized in Kentucky, Indiana, Tennessee, and Ohio by Campbell (1946). Subdivisions within the Chattanooga Shale were recognized in Tennessee and south-central Kentucky by Conant and Swanson (1961). Subdivisions within the Ohio Shale in Ohio were recognized by Pepper and others (1954). More recent studies have brought about refinement and redefinition of the subdivisions of the New Albany Shale in Indiana and adjacent parts of Kentucky (Lineback, 1970). In 1976 characterization studies of the Devonian shale in the Appalachian, Illinois, and Michigan Basins were initiated by the Morgantown Energy Research Center (MERC) of the Energy Research and Development Administration (ERDA), Morgantown, West Virginia. With the subsequent establishment of the U. S. Department of Energy (DOE), the facility became known as the Morgantown Energy Technology Center (METC). The characterization studies were part of the Eastern Gas Shales Project and were designed to encourage discovery and production of natural gas from the Devonian shale. Much of the research was performed by industry, State and Federal surveys, and universities. Investigations in Kentucky were performed by the Kentucky Research Group of the University of Kentucky, composed of personnel from the Department of Geology and the Kentucky Geological Survey. The Devonian-Mississippian black shale in eastern Kentucky was studied by other

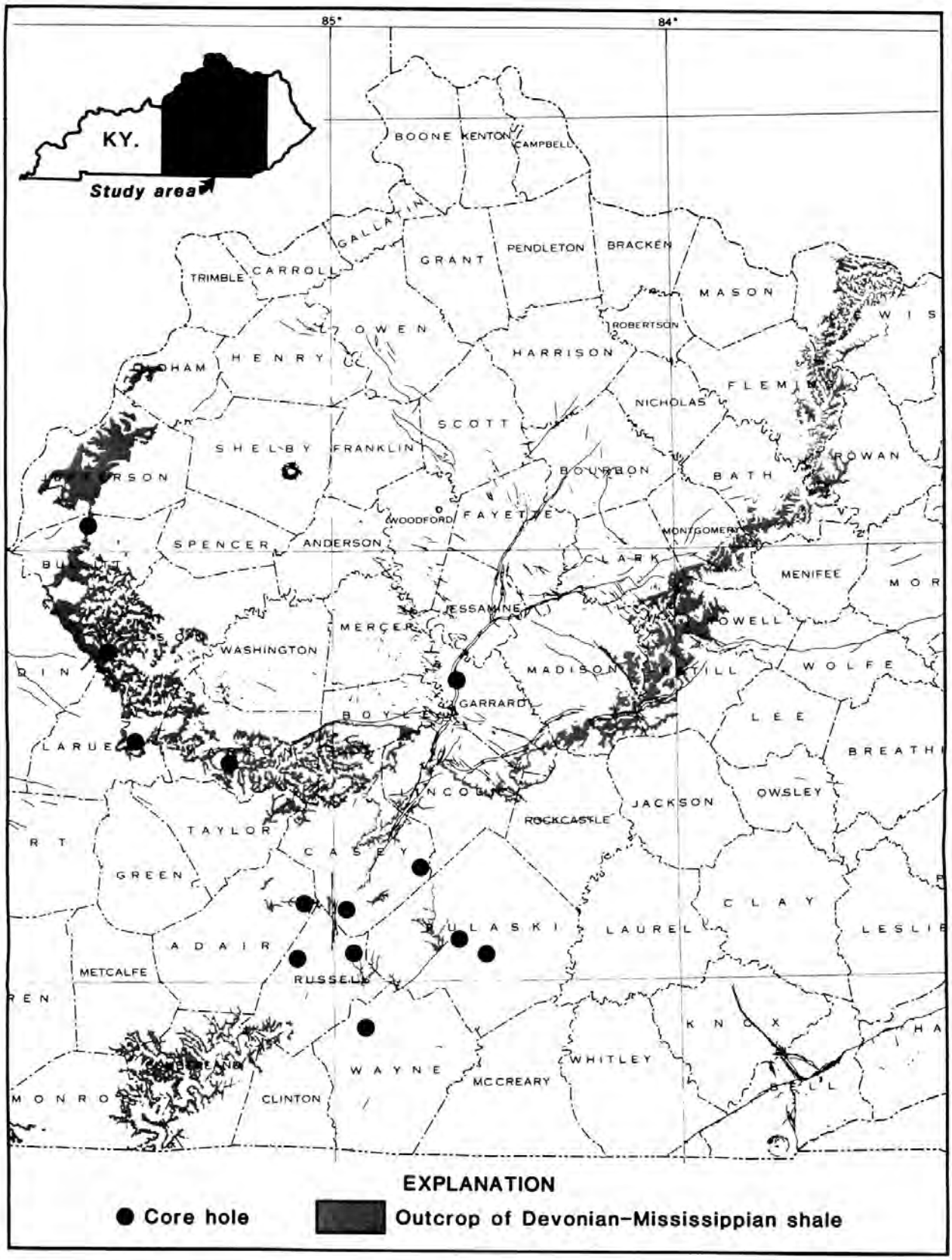

Figure 1. Outcrop of Devonian and Mississippian black shale and locations of core holes in this report.

contractors, including the University of Cincinnati and the U. S. Geological Survey. This work led to further subdivision of the Devonian shale in eastern Kentucky (Provo and others, 1978) and regional correlations throughout much of the Appalachian Basin (Wallace and others, 1977; Roen and others, 1978; Kepferle and others, 1978). Western Kentucky was studied by Schwalb and Norris (1978) in conjunction with studies of the Eastern Interior Basin by the state surveys of Illinois, Indiana, and Kentucky. Subdivision of the shale followed the recommendations of the Illinois State Geological Survey.

The subsurface study of western Kentucky was extended to include the outcrop on the western flank of the Cincinnati Arch, which had received scant attention in the past. The Kentucky Geological Survey cored five wireline holes near the outcrop (Fig. 1). These cores and eight additional cores stored at the Kentucky Geological Survey Core Library were described in detail. The latter cores came from locations throughout the Cumberland Saddle, south of the central outcrop belt (Fig. 2). The data derived from the study of these cores contributed greatly to refining stratigraphic correlation

Figure 2. Generalized distribution of Devonian and Mississippian black shale in east-central United States and major structural features of this report. (Modified from Conant and Swanson, 1961, plate 14.)

of the Devonian black shale sequence between the Appalachian Basin and the Eastern Interior Basin.

STRATIGRAPHIC FRAMEWORK

The Devonian and Mississippian black shale outcrops around the Lexington Dome, a structural high on the regional Cincinnati Arch. The arch extends from Cincinnati, Ohio, to the south-southwest through the Cumberland Saddle to the Nashville Dome. It marks the boundary between the Appalachian and Eastern Interior Basins.

The Devonian shale is commonly 20 to 40 feet thick in the Cumberland Saddle. It thickens northwestward to 470 feet in the Illinois Basin (Schwalb and Norris, 1978); it also thickens northward and eastward into the Appalachian Basin. In Kentucky it attains a thickness of more than 1,700 feet (Fulton, 1979).

The Devonian Ohio Shale that outcrops east of the Cincinnati Arch is subdivided into, in descending order, the Cleveland Member, the Three Lick Bed, and the Huron Member (Fig. 3). The Ohio Shale is overlain by the Bedford Shale-Berea Siltstone sequence and unconformably overlies limestone, dolomite, and shale that range in age from Middle Devonian to Late Ordovician. Within the Huron Member is a *Foerstia* zone (Schapf and Schweitering, 1970; Schweitering and Neal, 1978) that is a key biostratigraphic marker in the Appalachian Basin.

Southward from the eastern outcrop the Bedford-Berea sequence thins and the Sunbury Shale merges

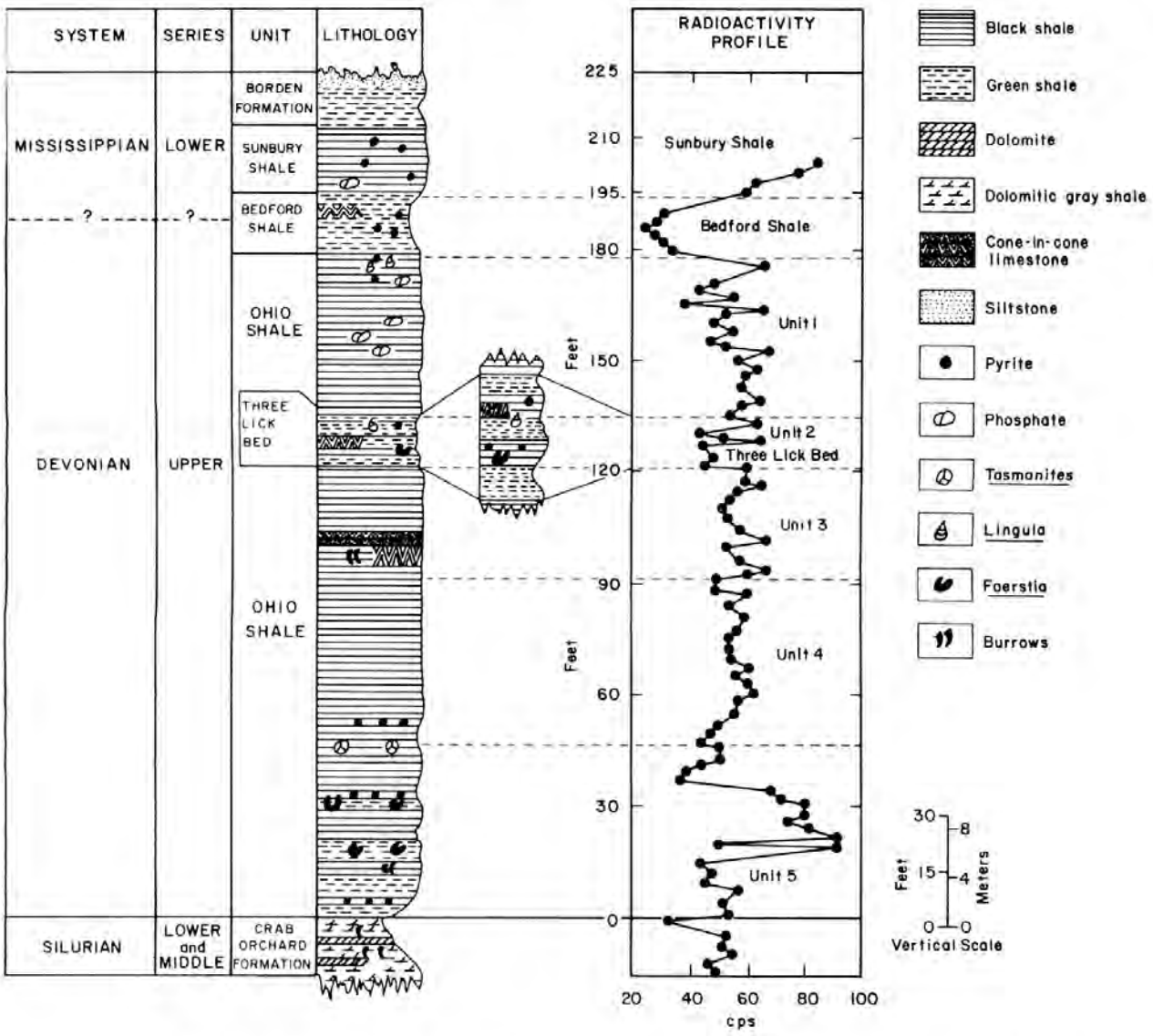

Figure 3. Columnar section with radioactivity profile of Ohio Shale at type location of Three Lick Bed near Morehead, Rowan County, Kentucky. (From Provo and others, 1978.)

with the Ohio Shale, at which position it becomes the Chattanooga Shale.

On the west side of the Cincinnati Arch, in the vicinity of Louisville, Kentucky, the New Albany Shale has been subdivided by Lineback (1970) on the basis of interbeds of greenish-gray and olive-gray clay shales. The subdivisions are, in descending order, the Clegg Creek, Camp Run, Morgan Trail, Selmier, and Blocher Members. These members can be recognized in the Kentucky Geological Survey core taken in Bullitt County, Kentucky, south of Louisville (Norm No. 1, Fig. 4).

Stratigraphic correlations in the Illinois Basin rely mainly on lithostratigraphy and wireline geophysical logs. Before discovery of this core, the westernmost location of *Foerstia*-bearing Devonian shale known to the authors was an outcrop on the Cumberland Saddle, along Minor Branch in northern Casey County, Kentucky. The state surveys of Indiana, Kentucky, and Illinois agreed to accept Illinois State Geological Survey terminology. The accepted subdivisions of the New Albany Shale, in descending order, are the Grassy Creek, Sweetland Creek, and Blocher Members. Schwalb and Norris (1978) prepared isopach maps and two east-west cross sections of these three units. The subdivisions as applied in western Kentucky are shown in the geophysical log of the Duchscherer No. 1 Berryman Well, Meade County, Kentucky (Fig. 5), but are not correlative with surface nomenclature. Early correlation between the Appalachian and Illinois Basins was based on the succession, in descending order, of an upper black shale, alternating interbedded beds of greenish-gray and black shale, a middle black shale, a lower unit of alternating beds of greenish-gray and black shale, and a lower thin black shale. These units corresponded to recognized subdivisions of the Ohio Shale on the eastern flank of the arch: the Cleveland Member, the Three Lick Bed, the upper Huron Member, the middle Huron Member (which contains Foerstian remains), and the lower Huron Member (which also contains Foerstian remains in its upper part) (Provo and others, 1978). On the western flank of the Cincinnati Arch, in the vicinity of Louisville, the corresponding units were identified by Provo and others (1978, p. 1) as the Clegg Creek, Camp Run, Morgan Trail, Selmier, and Blocher members of the New Albany Shale, as used by Lineback (1970). This correlation was questioned by Griffith (1977, p. 37), who found the greenish-gray shale beds difficult to trace west of the crest of the Cincinnati Arch. It was also questioned by Jordan (1979, p. 183), who failed to find, west of the Cincinnati Arch, trace fossils in the greenish-gray shale beds characteristic of the greenish-gray shale in the Three Lick Bed of the Ohio Shale. Correlation is complicated by the thinning of all units and the possible disappearance of some units in the Cumberland Saddle on the crest of the Cincinnati Arch, as noted previously.

Foerstia was reported from the west side of the Cincinnati Arch by Hoskins and Cross (1952, Fig. 7), but no stratigraphic position was given. Stratigraphic location of the *Foerstia* horizon was unsuccessful until Mr. Nelson Shaffer of the Indiana Geological Survey (written commun., 1980) referred the authors to core containing Foerstian remains. Before this core was uncovered, the westernmost location of a complete section of Devonian shale in the Cumberland Saddle that contained *Foerstia* is also present within 3 1/2 feet of the top of the New Albany Shale on the south side of Buttonmold Knob in Bullitt County, Kentucky; it also occurs from 33.90 to 36.75 feet in a core taken near the same location (Norm No. 1, Fig. 5). These recent discoveries of Foerstian remains in the upper part of the New Albany section make possible a more reasonable correlation between the Appalachian and Illinois Basins. The section above the *Foerstia*, east of the Cincinnati Arch is represented in Norm No. 1 by the upper 3 1/2 feet of the New Albany Shale (Fig. 6).

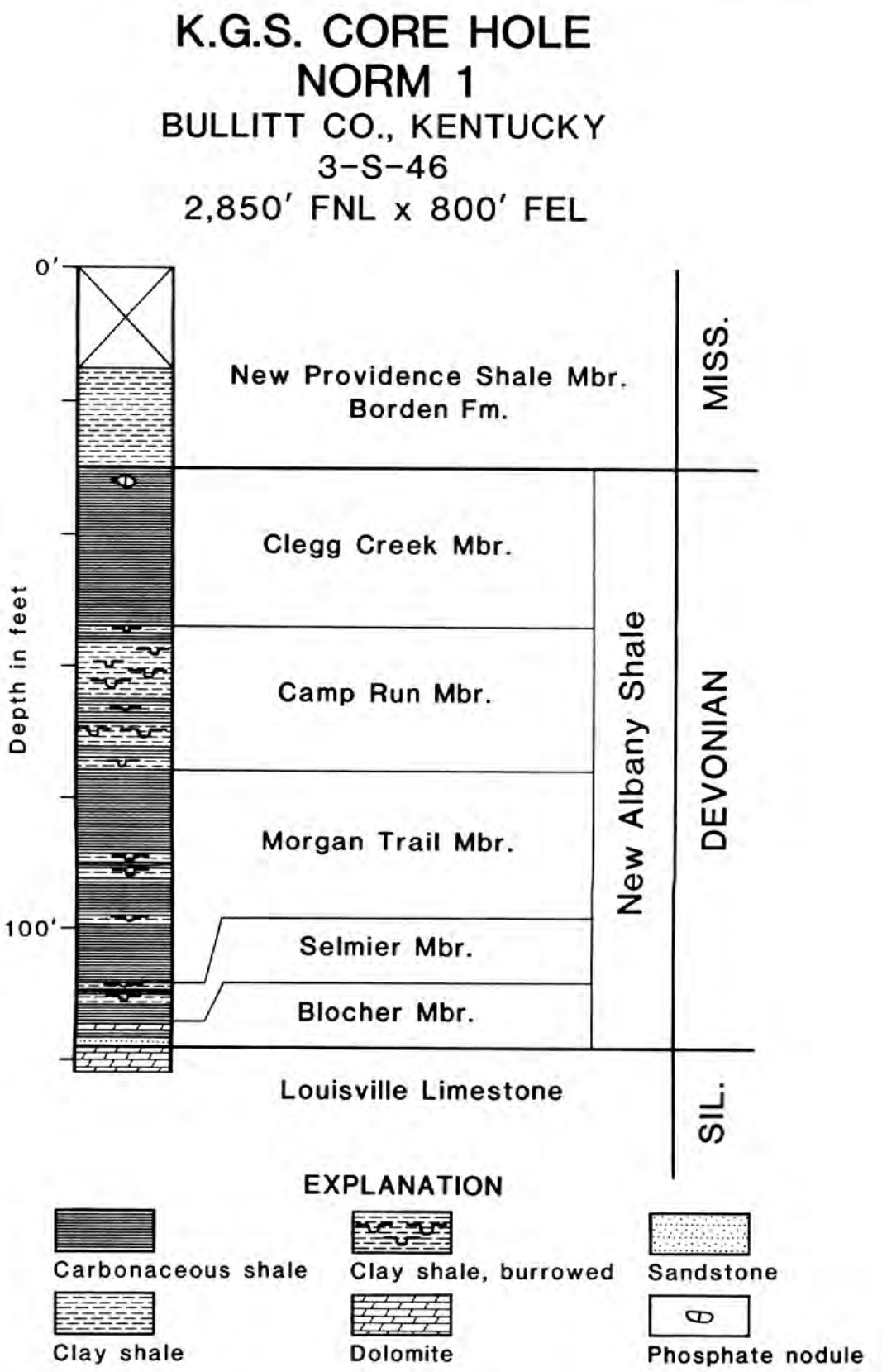

Figure 4. Columnar section of Norm No. 1 core hole, Bullitt County, Kentucky, illustrating Lineback's (1970) stratigraphy.

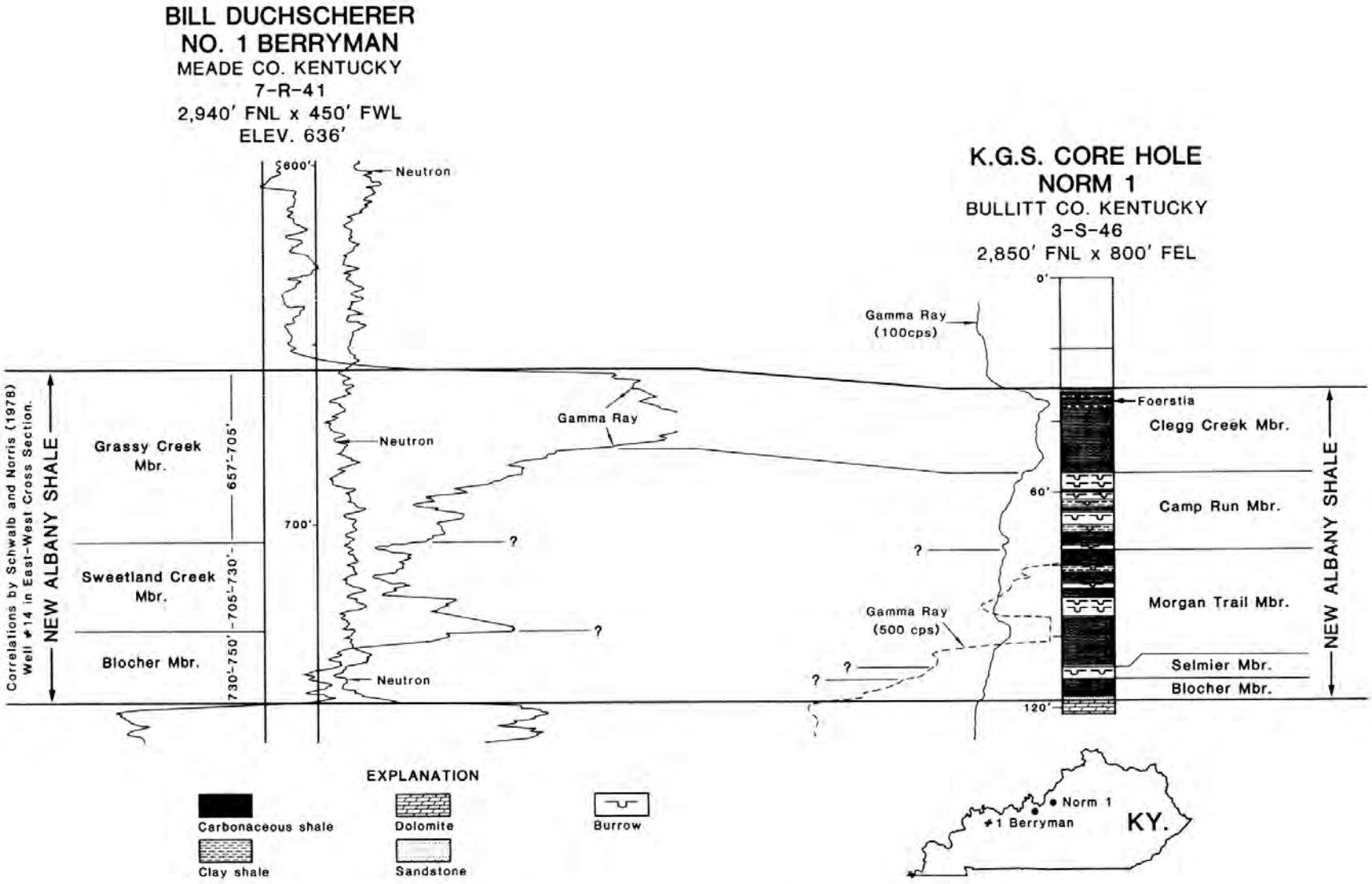

Figure 5. Relationship between surface and subsurface stratigraphy in Eastern Interior Basin. Figure

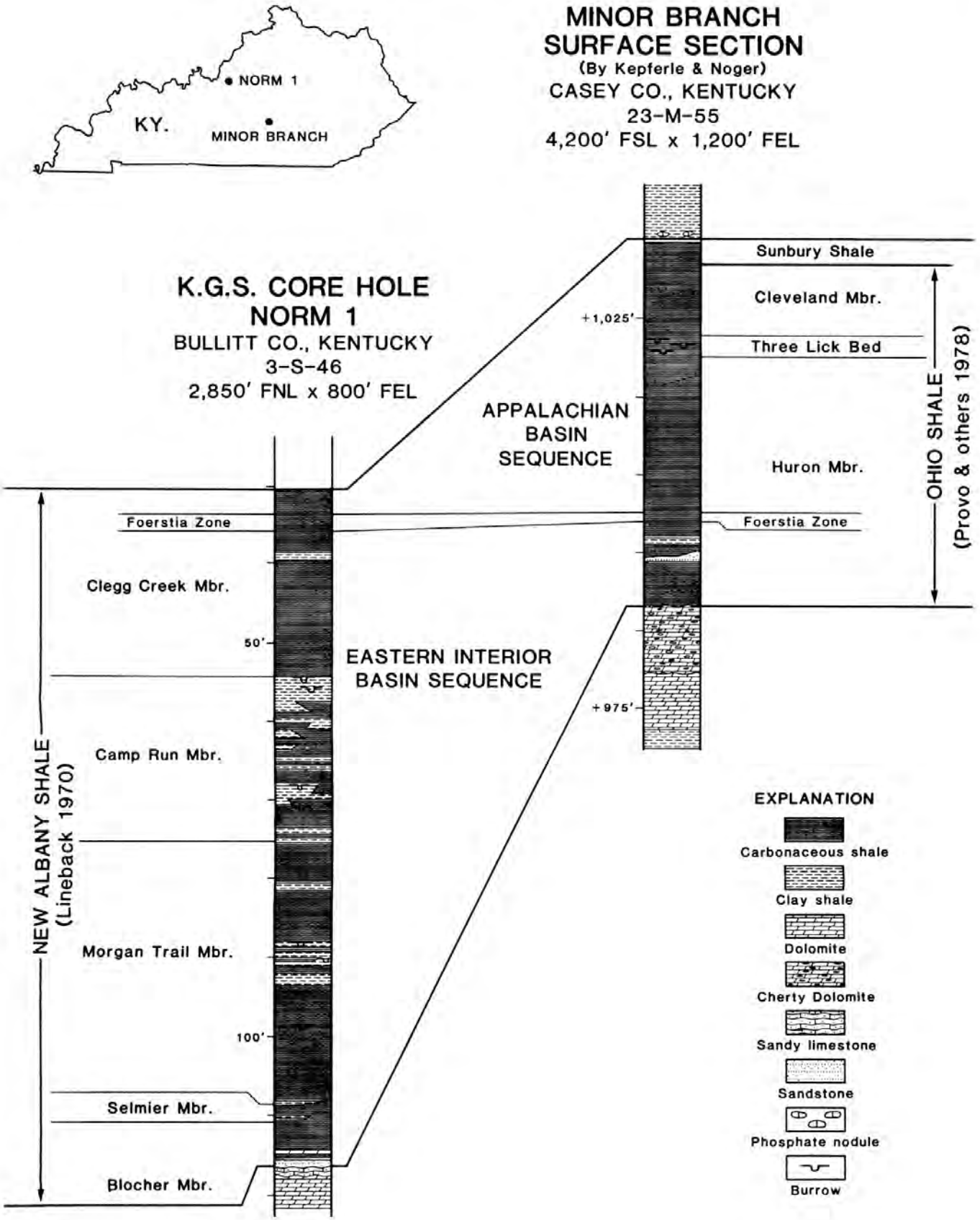

Figure 6. Correlation between Appalachian Basin and Eastern Interior Basin.

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