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Long-Range Petroleum Migration in the Illinois Basin[1]

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ABSTRACT

The distribution of oil fields in the Illinois basin overlaps but extends considerably northward from the area where the New Albany Group, the basin's most prolific source rock, has generated oil. Oils from reservoirs in Silurian strata from central and western Illinois can be correlated geochemically and isotopically to bitumen from the New Albany near the southern tip of Illinois. We believe that these oils migrated long distances, perhaps 100 km (62 mi) or more from the south or southeast. Migration probably occurred late in the basin's history, after basin sediments were fully compacted, in response to a regional northward flow system set up by tectonic uplift in the south. The hydrodynamic drive for migration during this period was comparable in magnitude to the component of buoyant force acting along migration pathways; both hydrodynamic and buoyant forces contributed to migration. Migration efficiency and velocity are greatest when oil saturates a small part of the carrier bed's porosity. Capillary forces can aid migration by segregating oil into heterogeneities such as especially porous laminae, fractures, or karst channels in carrier beds. We suggest that the oil migrated through Devonian and Silurian carbonates along the weathered and karstified surface of a regional unconformity that formed during Kaskaskia deposition.

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INTRODUCTION

The distribution of petroleum production from the Illinois basin extends considerably beyond the area where source beds have generated oil (Figure 1). Almost 3.5 million metric tons (t) (26 million bbl) of oil were produced in Illinois during 1988 and cumulative production for the basin exceeded 570 million metric tons (4.1 billion bbl) by that year. Significant quantities of petroleum are produced from fields widely separated from known oil sources. These oils apparently migrated laterally over paths of many tens and perhaps more than 150 km (93 mi).

Accounts of petroleum migration over long distances in the Mid-Continent of North America are not uncommon. On the basis of the distribution of oil fields in the Williston basin, Dow (1974) argued that petroleum there has migrated more than 150 km (93 mi) from its source. Migration over similar distances is inferred in the Denver basin (Clayton and Swetland, 1980). Other descriptions of long-range migration include the Big Horn and Powder River basins in Wyoming (Sheldon, 1967) and the Alberta basin (Demaison, 1977; Moshier and Waples, 1985; Garven, 1989). Oliver (1986) suggested that long-range migration in North America is a general phenomenon occurring during periods of tectonic deformation along the plate margins.

In this paper, we define the migration in the Illinois basin on the basis of shale petrography and geochemical correlations. The basin's structure and stratigraphy are shown in Figures 2 and 3. We emphasize the origin of oil found in shallow reservoirs, mostly in Silurian strata, north and northwest of the central basin (Figure 1). Oil produced from these reservoirs comprises a small fraction of the basin's production (Figure 3), but is the most interesting for studying migration because it seems to have migrated farthest from source beds.

We argue that this oil, produced from reservoirs more than 200 km (124 mi) from the basin's depocenter, was derived from Devonian source rocks in or near the deep basin. We then use quantitative models of the basin's paleohydrology to investigate the past subsurface conditions that drove the migration. We conclude that long-range migration was not related to processes occurring as the basin subsided and filled. Rather, lateral migration probably occurred during the Mesozoic in response to a hydrologic regime that resulted from tectonic uplift in the southern part of the basin.

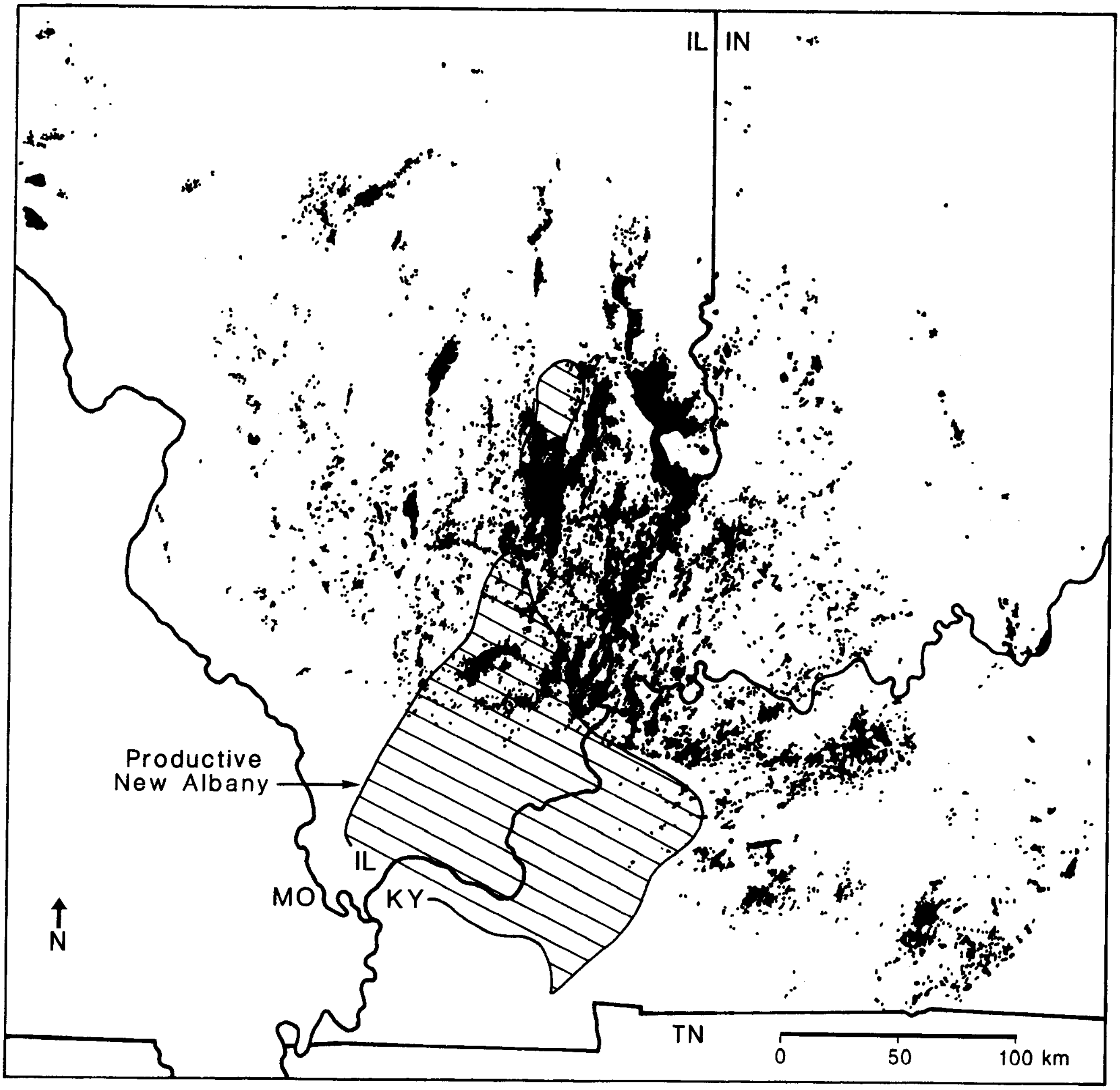

Figure 1—Areas of petroleum production (shown in black) in the Illinois basin (Howard, in press) and the extent of facies of the Devonian–Mississippian New Albany Group that Barrows and Cluff (1984) identified as prolific oil sources on the basis of organic facies, thermal maturity, and petrographic evidence (pattern). Source beds may extend considerably beyond the area labeled productive, as discussed in text.

GEOCHEMICAL CORRELATION AMONG OILS AND SOURCE BEDS

Many of the oils from the outlying reservoirs in Silurian strata can be correlated by their organic geochemistry and isotopic compositions to source beds of the Devonian–Mississippian New Albany Group in the deep basin. The New Albany Group is widespread through the deeper basin and has depocenters near the southern and western margins (Figure 4). These rocks have long been considered to be an important petroleum source because of their organic-rich facies and stratigraphic position relative to producing fields (Barrows and Cluff, 1984).

Figure 5 shows the gas chromatograms of two whole-oil samples from Sangamon County in west-central Illinois (Figure 4). The samples were taken from reservoirs

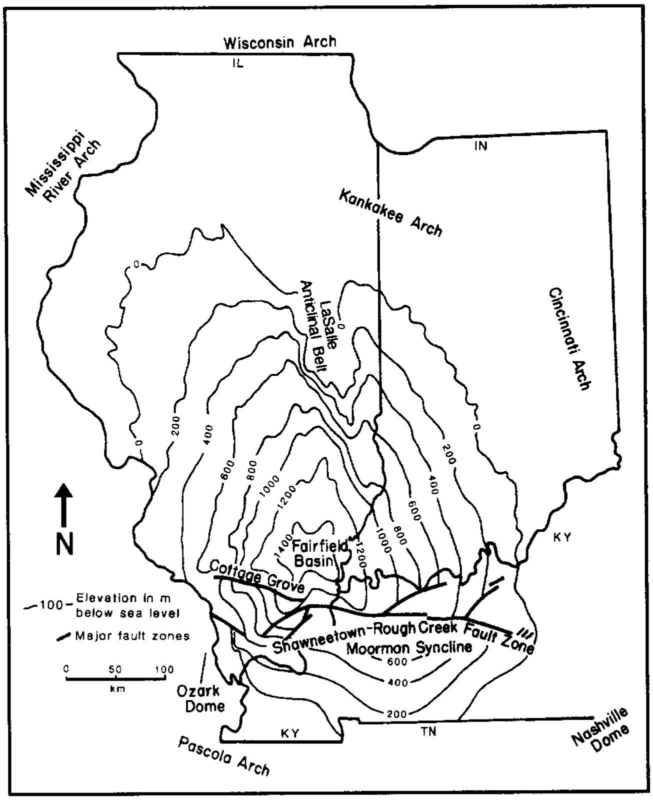

Figure 2—Structure map of the top of the Devonian–Mississippian New Albany Group in the Illinois basin (contours in meters below sea level) showing regional fault systems and the arches that bound the basin (Barrows and Cluff, 1984).

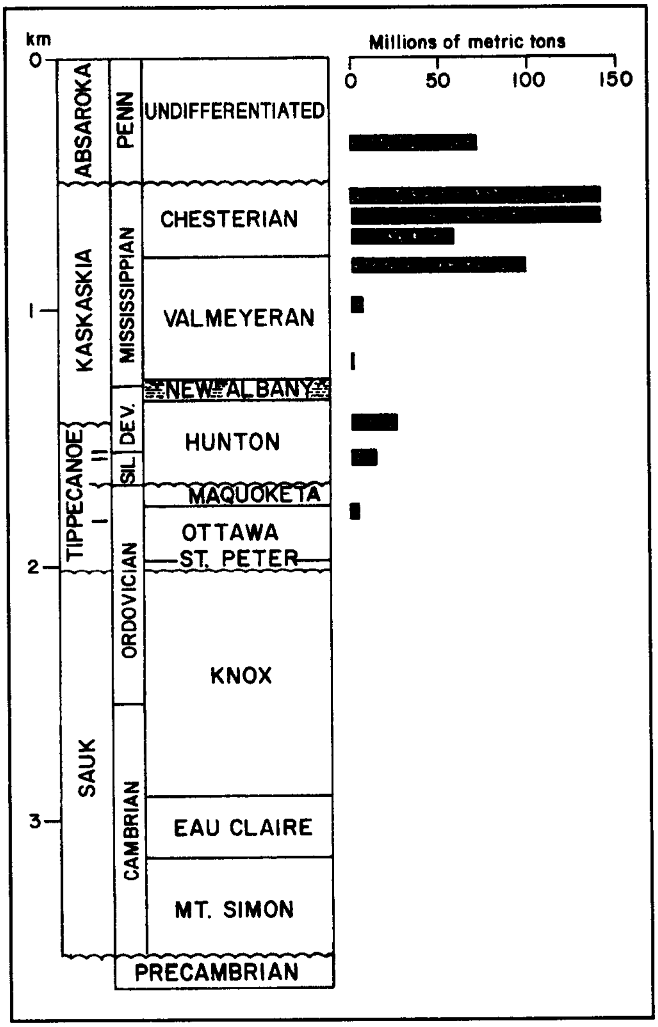

Figure 3—Generalized geologic column for the Illinois basin and stratigraphic distribution of cumulative oil production to 1983 (Howard, in press) (updated from Bell et al., 1964).

in Silurian strata at about 500 m (1640 ft) depth. The chromatograms are representative of those obtained from many of the outlying petroleum occurrences north and northwest of the basin (Hatch et al., in press).

In Figure 6, we compare the organic geochemical composition of the saturate fraction of an oil sampled in Sangamon County (Figure 4) with that of an extract of the New Albany from Franklin County, Illinois, about 200 km (124 mi) to the south–southeast. The New Albany sample is from an area of the deep basin where the shale is rich in organics and thermally mature (see next section). The oil and shale extract samples are similar in their chromatographic characteristics and carbon isotopic compositions.

Mass fragmentograms of m/e 191 and m/e 217 (Figure 7), representative of the triterpanes and steranes in saturate fractions of the samples, indicate further geochemical similarity between the oil and shale extract. Such close correlations are common among outlying oils in the basin. Some outlying reservoirs may contain petroleum from Ordovician sources (Kruge et al., 1988; Hatch et al., in press), but oils from the New Albany are widespread in these outlying fields. Hatch et al. (in press), for example, correlated 22 of 24 samples from Silurian reservoirs to the New Albany source.

DISTRIBUTION OF PRODUCTIVE SOURCE BEDS

The area within which the New Albany Group is likely to have served as a petroleum source is limited by the distribution of oil-prone organic matter in these strata, and by the area where the organics have reached sufficient thermal maturity to produce oil. The amount and type of organic matter in this group of rocks is controlled by the shale's depositional environment, which is reflected by facies distribution within the group (Cluff, 1980; Barrows and Cluff, 1984). Near the southern depocenter, the New Albany shales commonly contain

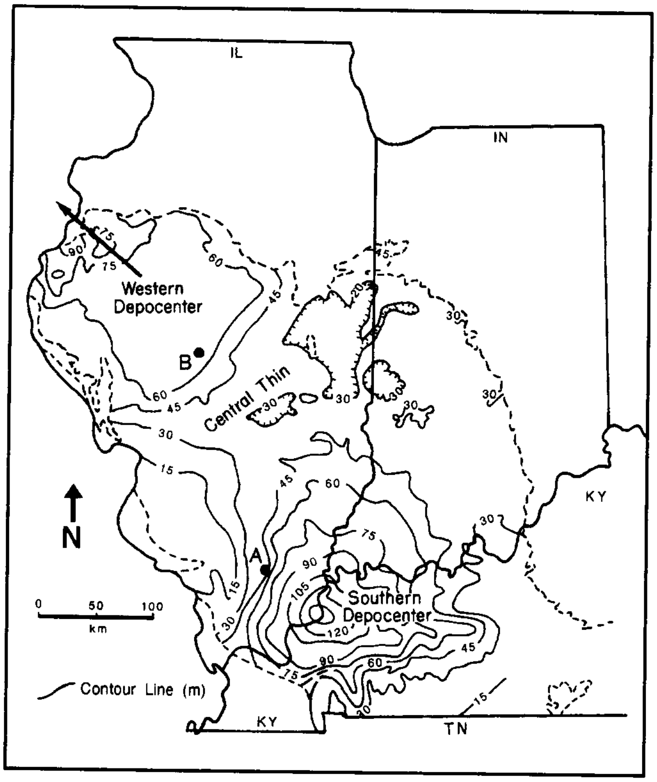

Figure 4—Isopachous map (contours in meters) of the New Albany Group (Devonian–Mississippian) showing southern and western depocenters (Barrows and Cluff, 1984). Point (A) shows location of oil samples analyzed in Figures 5–7, and (B) shows the Sangamon County location of source rock analyzed in Figures 6–7.

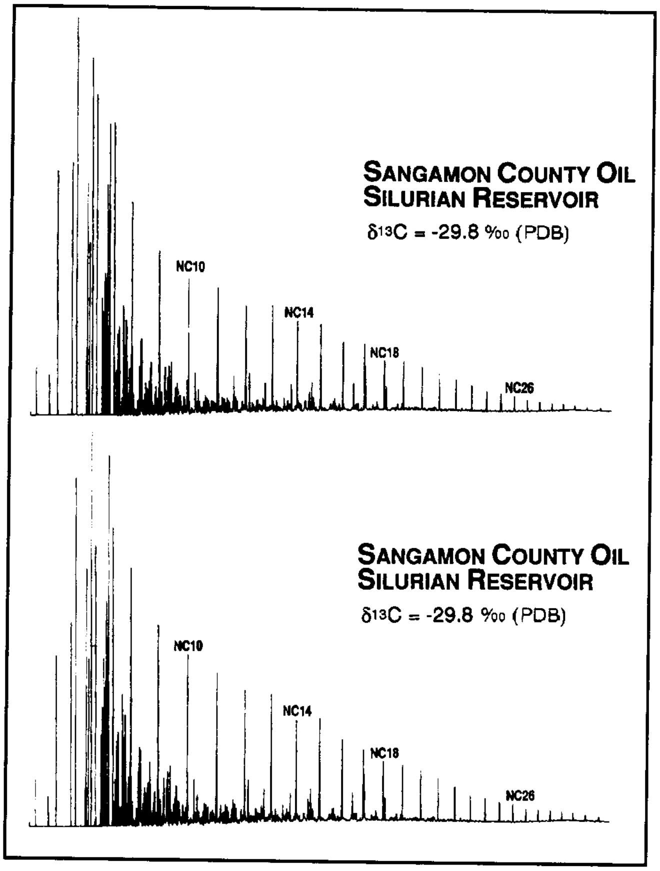

Figure 5—Gas chromatograms and stable carbon isotopic compositions of two whole-oil samples from Sangamon County in central Illinois (location shown in Figure 4).

laminated brownish black and black beds (Figure 8) deposited in relatively deep, anoxic waters. The anoxic facies generally contains 2.5–9% organic carbon and is the richest of the source beds in the Illinois basin. About 90–95% of the organic matter in this facies is well-preserved amorphous material interpreted to be of marine origin; these organics are typical of the oil-prone type II kerogen, as defined by Tissot et al. (1974). Solid hydrocarbons or bitumens occur in increasing amounts and the amorphous kerogen is progressively altered to a fragmented organic material with greater depth and thermal maturity (Barrows and Cluff, 1984). These observations indicate that the organic-rich, anoxic facies has likely generated significant amounts of oil.

The anoxic facies grades northward and westward into a bioturbated, greenish gray shale facies. Here, organic matter, which is predominantly humic, has been incompletely preserved in a moderately oxygenated environment (Barrows and Cluff, 1984). In contrast to the anoxic facies, the moderately oxic facies contains only 1–2% organic carbon. The organics are characteristic of type III kerogen and constitute a poor petroleum source.

On the basis of vitrinite reflectance measurements (Figure 9) (Barrows et al., 1979) and Rock-Eval analyses (Hatch et al., in press), the New Albany has reached sufficient thermal maturity to generate oil over limited areas of the basin. The New Albany reached this level of maturity in southeastern Illinois and northwestern Kentucky, as well as along a narrow band in a synclinal belt along the Indiana border. Hence, the New Albany is likely to have generated oil prolifically only within relatively restricted areas (Barrows and Cluff, 1984).

The areas where source rocks have generated oil prolifically account for a significant fraction of the petroleum that has been discovered in the basin, but these areas are strikingly small compared to the areal distribution of all the producing reservoirs in Illinois (see Figure 1). The reservoir distribution might be better explained by attributing some minor source potential to the New Albany in the outlying areas, where the source is less mature and poorer in organics. The New Albany may indeed have produced oil over a broader area, considering the uncertainty in relating vitrinite reflectance measurements to the onset of hydrocarbon generation.

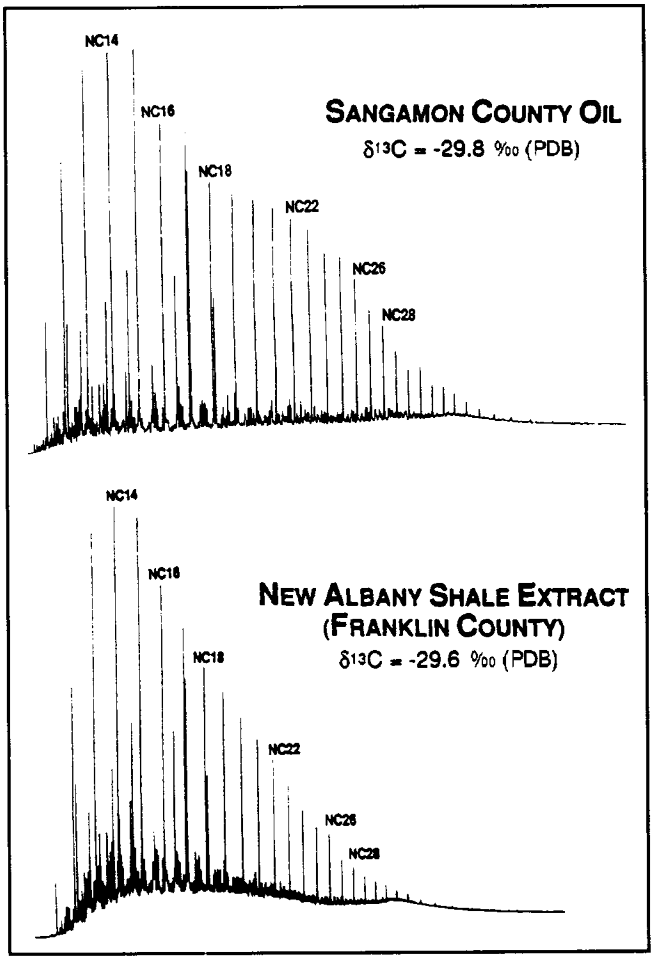

Figure 6—Gas chromatogram and stable isotopic composition from saturate fraction of one oil sample from those given in Figure 5 compared to chromatogram of bitumen sample from the New Albany Group in Franklin County, southern Illinois (location shown in Figure 4).

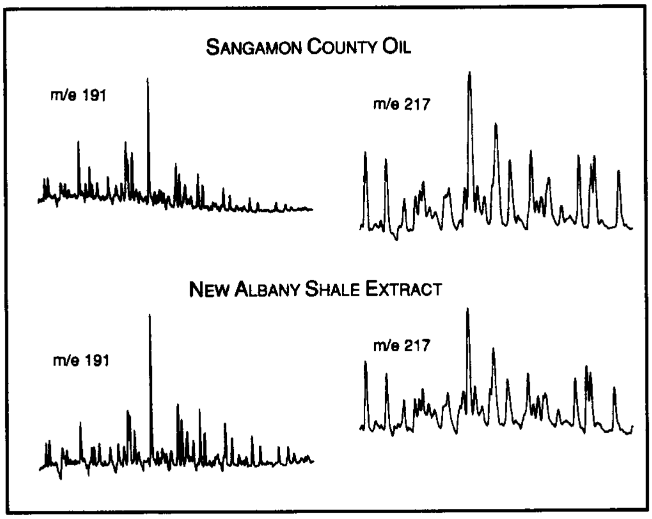

Figure 7—Mass fragmentograms for m/e 191 and 217 of the oil and extract samples listed in Figure 6.

For this reason, Barrows and Cluff (1984) delineated a second area that contains at least some beds of the anoxic facies and where vitrinite reflectance is at least 0.5%. To date there is no petrographic evidence that hydrocarbons were generated in these rocks in sufficient quantity to have been expelled into carrier beds; nonetheless, some of the marginal beds may have produced oil.

Significant areas of production, however, cannot be explained even by invoking a marginal source. About 10% of the petroleum reserves of the Illinois basin lie outside the zones of prolific and marginal oil generation. Such production occurs where the New Albany is unlikely to have produced hydrocarbons locally because of its thermal immaturity and lack of appreciable amounts of oil-prone organic matter. Many of the producing fields in Silurian strata, for example, are far removed from viable source rocks. Widely removed fields in Silurian strata include those in and near Sangamon, Christian, and Pike Counties, Illinois (occurrences in northwest corner of Figure 1).

Accurately determining migration distances or the amounts of oil displaced during migration is difficult because of uncertainty in the areal extent of Devonian source rocks and the paucity of geochemical data. These outlying oils must have migrated at least tens of kilometers from a marginal source area or for over 100 km (62 mi) from an area where the New Albany generated oil prolifically; the westernmost occurrences reported by Howard (in press) and Hatch et al. (in press) must have traveled even farther. Given the lack of evidence that petroleum might have been generated in outlying rocks, long-range migration of oils from the areas of intense generation seems the most viable explanation of the distribution of New Albany–sourced oil.

BASIN PALEOHYDROLOGY

Petroleum migrates in the subsurface partly in response to the subsurface hydraulic gradients that drive groundwater flow through deep strata. Thus, knowledge of a basin's hydrostratigraphy and deep groundwater flow subsequent to the onset of petroleum generation is fundamental to understanding oil migration.

Hydrostratigraphy

The Illinois basin began to subside slowly and fill with sediments during the Cambrian and continued to

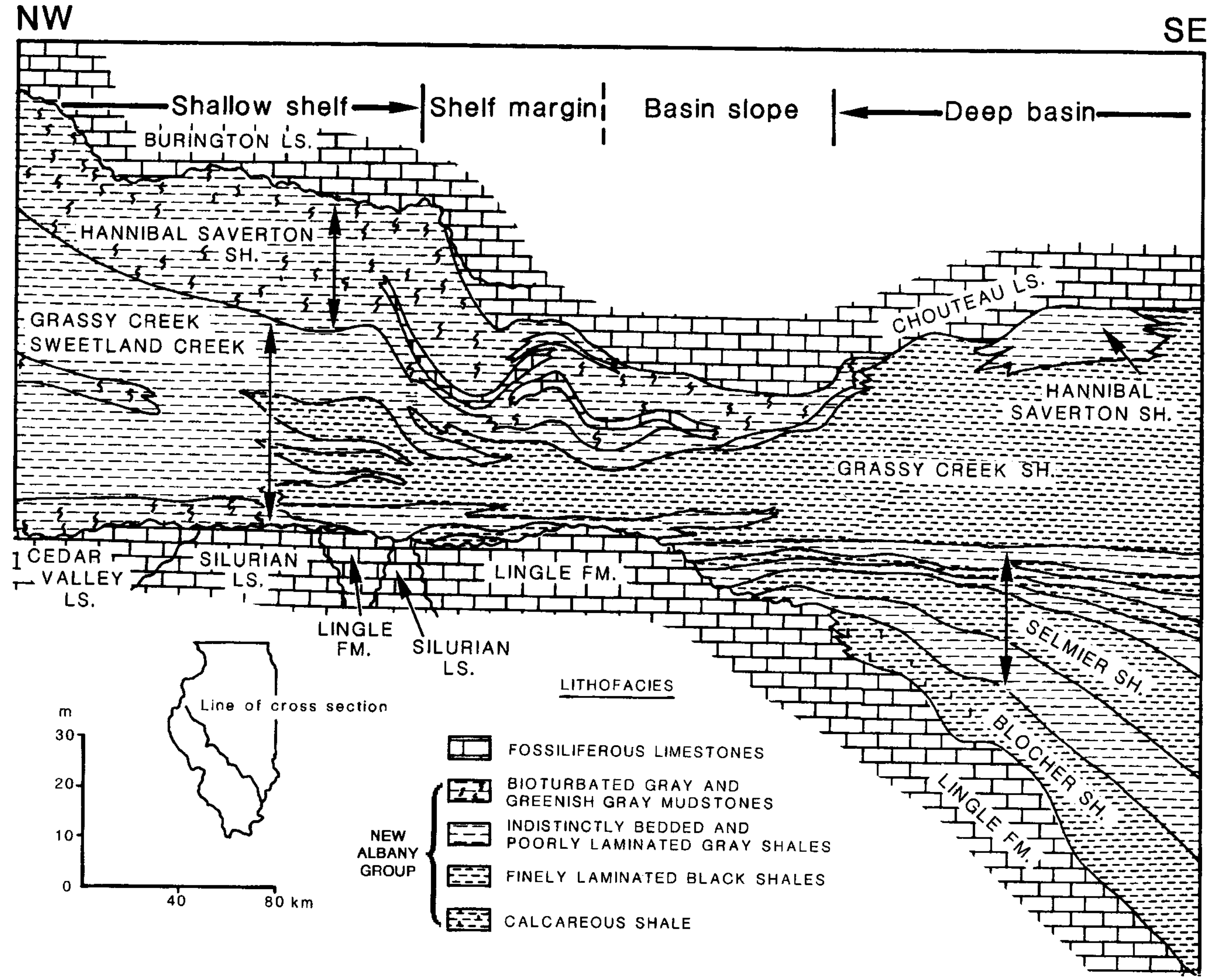

Figure 8—Stratigraphic cross section of the New Albany Group showing facies changes from the western to southern depocenters (Barrows and Cluff, 1984).

do so through the Pennsylvanian and into the Permian (Kolata and Nelson, in press). During the Paleozoic, the developing basin was an elongate embayment that trended northeasterly and was open to the sea along its southern margin. Six major unconformities mark hiatuses in deposition during this time. More than 4 km (2.49 mi) of sedimentary rocks are preserved in the basin within Illinois, and more than 7 km (4.35 mi) occur in the Rough Creek graben in western Kentucky.

The lowermost strata within Illinois are composed largely of Cambrian and Lower Ordovician orthoquartzites and carbonates. These formations rest unconformably on crystalline Precambrian basement and extend throughout much of the basin. Deep strata, which are strikingly shale poor, are dominated hydrologically by sheet sandstones, especially the Cambrian Mt. Simon and Ordovician St. Peter formations. These clean sandstones are notable for their high permeabilities (Buschbach and Bond, 1974), which reflect the paucity of clays in early sediments (Dalrymple et al., 1985). For example, the trend of permeability versus porosity for these sandstones is two orders of magnitude higher than the trend for less-clean sandstones from the Gulf of Mexico basin (Figure 10). Because of their high permeabilities and hydraulic continuity, the deep sandstones form a basal aquifer complex (Bond, 1972).

An Upper Ordovician through Mississippian interval of carbonate rocks interbedded with sandstones and shales overlies the basal sandstones. The Ordovician Maquoketa and Devonian–Mississippian New Albany groups fall in this interval. These shales, believed to be the most significant petroleum sources, form regional aquitards. Sandstones here are less continuous than in the lower strata, but some, such as the Devonian Dutch

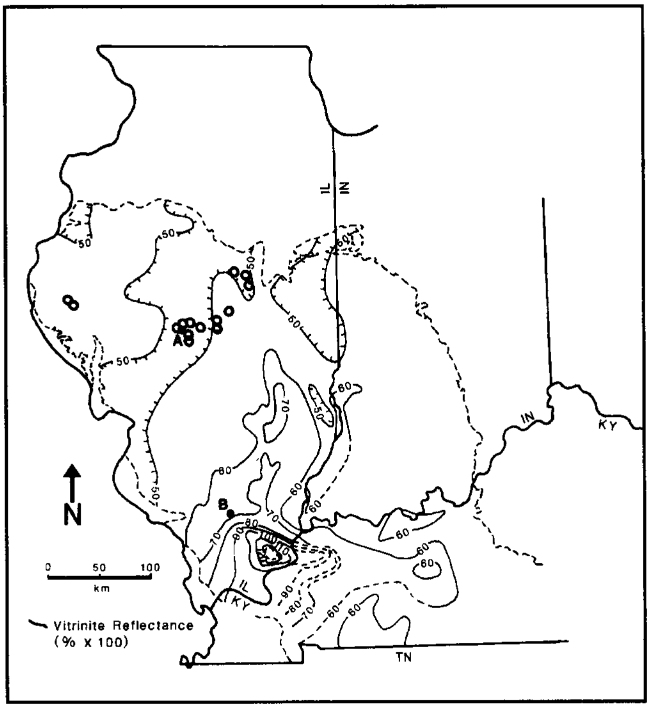

Figure 9—Contour map of vitrinite reflectance of the New Albany Group based on analyses from 238 wells. Values are mean percent reflectance in oil of at least 20 measurements per sample (Barrows et al., 1979). Also shown are sampling locations (A) and (B) from Figure 4, and locations of some outlying oils correlated by Hatch et al. (in press) to the New Albany source. Dashed lines show the limits of the strata; tic marks show areas where the New Albany Group is less than 50 m thick.

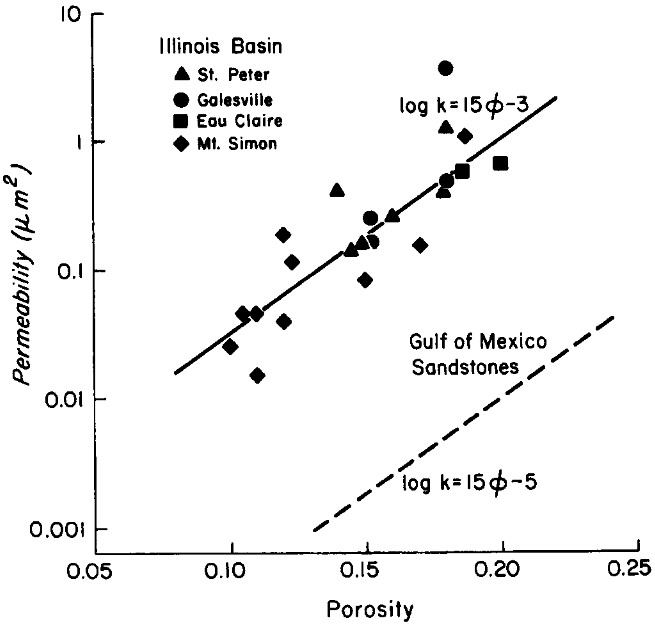

Figure 10—Permeabilities of Cambrian and Ordovician sandstones as determined from drill-stem tests at injection wells in the Illinois basin, plotted against porosity (data from Buschbach and Bond, 1974). Solid line is regression fit used in hydrologic calculations. Dashed line shows trend of permeability with porosity for sandstones of the Wilcox Group and Vicksburg and Frio formations of the Gulf of Mexico basin (Loucks et al., 1984).

Creek, are sufficiently widespread to likely act as aquifers on regional scales.

The basin is capped by Pennsylvanian strata composed of sandstone, shale, limestone, and coal. With the exception of a few Permian relicts (Kehn et al., 1982), these are the youngest Paleozoic deposits preserved in Illinois. Damberger (1971) suggested that about 1.5 km (4921 ft) of sediments were deposited in southernmost Illinois after the Late Pennsylvanian and subsequently eroded. This estimate agrees with reconstructions of sedimentation following the Alleghenian orogeny that predict deposition of about 1 km (3280 ft) of Permian sediments there (Beaumont et al., 1988), and would explain the high ranks of Pennsylvanian coals in the southern part of the basin.

The southern basin was deformed during the late Paleozoic through the Mesozoic by uplift of the Pascola arch and later downwarp of the Mississippi embayment (Marcher and Stearns, 1962). The Pascola arch was a domal uplift comparable in size to the present-day Black Hills and Nashville dome. The arch began to rise some time after the Early Permian and was fully developed in the Early to middle Cretaceous. The Mississippi embayment subsided in the Late Cretaceous, burying the arch and the southern one-third of the basin. This cycle of uplift and subsidence gave the basin its present spoon shape.

Paleohydrologic Models

We used computer simulation techniques (Bethke et al., 1988) to reconstruct the past groundwater hydrology of the Illinois basin. In the computer models, we combined estimates of the properties of the basin's hydrostratigraphy with information about the basin's evolution (such as burial rates and the development of topographic relief) to calculate past groundwater flow. The mathematical basis of the models is described in detail elsewhere (Bethke, 1985, 1986a).

The numerical technique works by calculating the hydraulic potential of groundwaters at points throughout the basin, and then using variation in the calculated potentials to compute groundwater discharge rates and directions. Hydraulic potential, defined as the mechanical energy of a unit volume of groundwater (assumed to be of constant density), represents the net amount of work done on the groundwater to bring it to ambient pressure (i.e., the $V \cdot dP$ work of thermodynamics) (Lewis and Randall, 1961) and carry it through the Earth's gravitational field to its current elevation (Hubbert, 1940). The potential Φ can be calculated from pressure P and depth z below an arbitrary elevation (sea level in this paper), as

$$\Phi = P - \rho g\, z, \tag{1}$$

where ρ is the density of water and g is the acceleration of gravity. The difference between Φ at a point and the value at the basin surface above that point is the deviation in pressure from a hydrostatic gradient.

Groundwater moves from areas of high to low potential (i.e., toward areas of lower mechanical energy), much as heat moves toward areas of lower temperature. The rates and directions of flow depend on the permeability structure of the subsurface. In two dimensions, the horizontal (x direction) and vertical discharges are given by Darcy's law

$$q_x = -\frac{k_x}{\mu}\frac{\partial \Phi}{\partial x}$$

$$q_z = -\frac{k_z}{\mu}\frac{\partial \Phi}{\partial z}.$$

Here, q_x and q_z are specific discharge (the volume of groundwater flowing across a plane of unit area per unit time) along x and z, and k_x and k_z are permeabilities in the primary directions, and μ is groundwater viscosity. The overall rate and direction of discharge are the vector sum of the directional discharges.

The velocity of groundwater flow through a porous rock is somewhat greater than the numerical value of discharge, even though both velocity and discharge can be expressed in the same units. Consider, for example, a groundwater discharging at 1 cm^3 (0.06 in.^{3}) of fluid per cm^2 per year (or 1 cm/yr) through a rock with 20% porosity. Because the fluid moves only through the pore space of the rock, each cubic centimeter of fluid must migrate forward by 5 cm/yr (2 in./yr). The general relationship is

$$v_x = \frac{q_x}{\phi}\,;\quad v_z = \frac{q_z}{\phi}\,,$$

where ϕ is the interconnected porosity of the rock. The overall velocity is the vector sum of the x and z components.

Gradients in hydraulic potential sufficient to drive flow on the basin scale can develop in various ways. In basins in which sediments compact during burial, the sediments transfer pressure to the pore fluid and increase the fluid's hydraulic potential (equation 1). The widespread zone of geopressured sediments in the Gulf of Mexico basin formed by this process (Dickinson, 1953; Harrison and Summa, 1991). Fluid migrates out of the overpressured strata toward the surface or basin margins in response to the increased potential. Bredehoeft et al. (1988), for example, showed that sediment compaction drives regional groundwater flow through the subsurface of the Caspian basin.

Topographic relief across basin surfaces also produces potential gradients that can drive basin-scale flow (e.g., Hubbert, 1940; Tóth, 1962, 1963). In this case, increased potentials develop not in response to changes in pressure along the top surface, which is atmospheric, but due to variation in the elevation of groundwater along the water table. Groundwater recharges the basin at high elevation, where the fluid has the highest potential energy (equation 1), and discharges from basin strata at low elevation. Darton (1909), in his study of the hydrology of South Dakota, was among the first to recognize the role of even moderate relief in driving regional groundwater flow.

Hydrologic Properties

The simulations presented in this study reflect, in part, the properties assumed for the medium, principally the compaction rate during burial and the permeability of deep strata. Strata are taken to be interlayerings of three rock types: sandstone, shale, and carbonate. In the calculations, each rock type compacts during burial to an equilibrium porosity corresponding to the weight of overlying sediments. Porosity varies with burial depth Z according to

$$\phi = \phi_0\, e^{-\mathrm{b}Z} + \phi_1\,, \tag{2}$$

where ϕ_0, b, and ϕ_1 are constants. The constants used in the simulations (Table 1) give porosity profiles that approximately match observed compaction of Illinois basin sandstones (Metarko 1980; Hoholick, 1980), Mid-Continent shales (Athy, 1930), and carbonate rocks from a continental platform (Halley and Schmoker, 1983).

The model results are especially sensitive to the permeabilities assumed for sandstones because of the sandstone aquifers that extend throughout the basin. Sandstone permeability in the simulation varies with porosity according to the correlation

$$\log\, k_x = A\phi + B, \tag{3}$$

where A and B are constants for each rock type. Permeability does not exceed 1 μm^2 (1 darcy) at any point. By this correlation, permeability decreases rapidly as a sediment compacts. We estimate vertical permeability from k_x by assuming a local anisotropy k_x/k_z.

Figure 10 shows measured permeabilities of deep sandstone aquifers in the Illinois basin (Buschbach and Bond, 1974) plotted against porosity, and a semilog regression of the data giving the best-fit values for A and B of 15 and –3, respectively. The figure also shows a best-fit line for measured permeabilities of Tertiary sandstones from the Gulf of Mexico basin (Loucks et al., 1984). The correlation for Gulf sandstones has the same

Table 1. Coefficients Used to Calculate Porosity and Permeability

	Porosity*			Permeability**		
	ϕ_0	b (km^{-1})	ϕ_1	A	B	k_x/k_z
Sandstone	0.40	0.50	0.05	15	−3	2.5
Carbonate	0.40	0.55	0.05	6	−4	2.5
Shale	0.55	0.85	0.05	8	−7	10

*By equation (2), expressed as a fraction.
**By equation (3), in μm^2 (darcys); permeability ≤1 μm^2 at all points.

slope A, but the intercept B is two log units less than the value for sandstones from the Illinois basin. On the average, then, basal sandstones of the Illinois basin are more permeable by a factor of 100 than Gulf sandstones of the same porosity, probably because of the small clay content in the basal aquifers of the Mid-Continent.

The permeabilities of carbonate rocks and shales in the basin are more difficult to estimate than those of sandstones principally because of a lack of representative measurements in the deep basin. Fortunately, these estimates are less critical to the results of this study than those for sandstones (hydrologic models calculated using differing correlations for carbonate and shale permeability are available by writing to C. M. Bethke). We set the correlation coefficients for shales and carbonates (Table 1) to fall within the typical ranges for these rock types (Freeze and Cherry, 1979). According to these assumptions, sandstones are more permeable than carbonates, which, in turn, are more permeable than shales. Because the interlayered rocks contrast in permeability, strata in the basin tend to conduct fluids laterally more readily than across strata.

Flow Driven by Sediment Compaction

We present models of two past groundwater flow regimes in the Illinois basin. The first simulation accounts for groundwater flow driven by sediment compaction as the basin subsided and infilled through most of the Paleozoic. The simulation follows sedimentation beginning with the onset of subsidence in the Late Cambrian and continuing through the Permian. The calculations employ a simplified basin cross section extending from the Fairfield basin, a depocenter in southern Illinois for much of the Paleozoic, for 400 km (249 mi) toward the north–northwest (Figure 11). The cross section passes to the west of the LaSalle anticlinal belt and east of the Mississippi River arch.

We divide basin strata into ten chronostratigraphic units (Table 2) for the calculation. Where possible, we chose the boundaries between units at unconformities so that the time units closely represent the basin's rock stratigraphy. The uppermost stratigraphic unit consists of up to 1.5 km (1 mi) of Permian sedimentary rocks that may have been deposited and subsequently eroded, as discussed previously. The Permian unit was included in

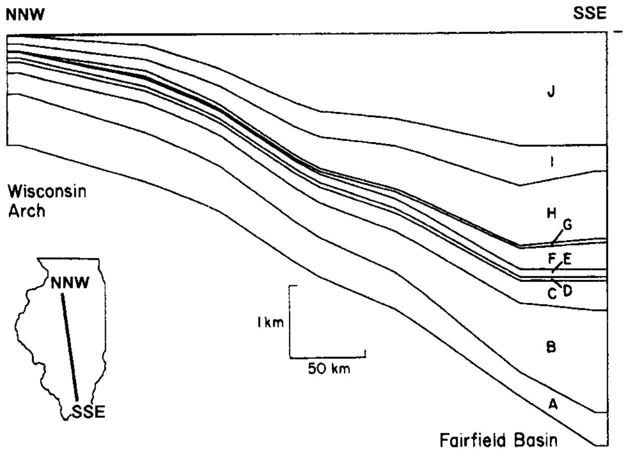

Figure 11—Cross section used in simulations of compaction-driven groundwater flow in Paleozoic. Section extends 400 km (249 mi) from the Fairfield basin to the flank of the Wisconsin arch. Chronostratigraphic units are described in Table 2.

the calculation to achieve the maximum duration and effect from compaction flow.

Simulation results for the end of the Pennsylvanian and the end of the Permian are shown in Figure 12. The Permian results represent the maximum likely duration of basin subsidence and compaction-driven flow in the Illinois basin. Arrows within the cross sections show the directions and true (i.e., average microscopic, rather than darcy) velocities of groundwaters relative to the medium. Contour lines are equipotentials that, in this figure, connect points where fluid pressures are equally in excess of hydrostatic.

The modeling results portray a flow system characterized by slow fluid velocities, and pore pressures that remain near hydrostatic. Throughout the simulation, fluids move less than about 2 km/m.y (1.2 mi/m.y.). Fluid velocity in compaction-flow systems that develop small excess pressures depends on the sedimentation rate (Bethke, 1985). Slow velocities shown in the simulation arise from the very gradual Illinois basin subsidence, which accepted sediment at an average rate of only about 30 m/m.y. (98 ft/m.y.) near its depocenter.

Fluid pressures in the simulation never exceeded hydrostatic by more than 0.01 MPa (0.1 atm). The greatest hydraulic potentials occur at moderate depth in a wedge-shaped distribution that developed from the draining effect of the basal aquifer complex. Groundwaters on the lower side of the wedge migrate stratigraphically downward, seeking areas of lesser potential.

The modeled distribution of hydraulic potentials differs markedly from the potentials in overpressured basins such as the Gulf of Mexico basin, where pressures can exceed hydrostatic by many tens of megapascals MPa (hundreds of atmospheres). Basins with

Table 2. Basin Hydrostratigraphy Assumed in Calculations

Hydrostratigraphic Unit	Chronostratigraphy System	Chronostratigraphy Series or Stage	Rock Stratigraphy*
J	Permian		Postulated Permian sediments
I	Pennsylvanian		All Pennsylvanian formations
H	Mississippian	Valmeyeran and Chesterian	Pope, Remaining Mammoth Cave Sgp, Top of Knobs to north
G	Mississippian	Kinderhookian	Basal Mammoth Cave Sgp to south, Kinderhookian Knobs Sgp
	Devonian	Upper Devonian	New Albany Gp (Knobs Sgp)
F	Devonian	Lower Devonian and Middle Devonian	Basal Knobs to north, Devonian Hunton Sgp
E	Silurian	Alexandrian and Niagaran	Silurian Hunton Sgp
D	Ordovician	Cincinnatian	Ordovician Maquoketa Gp, remainder of Ottawa Sgp to south
C	Ordovician	Champlainian	Ottawa Sgp, Glenwood Fm, St. Peter Ss
B	Ordovician	Canadian	Prairie du Chien Gp
	Cambrian	St. Croixan	Jordan Ss, Eminence Fm, Potosi Dol, Franconia Fm
A	Cambrian	St. Croixan	Ironton Ss, Galesville Ss, Eau Claire Fm, Mt. Simon Ss

*Abbreviations: Dol = dolomite, Fm = formation, Gp = group, Sgp = supergroup, Ss = sandstone.

widespread overpressured zones generally contain shaly sediments deposited at rates of about 1 km/m.y. (3280 ft/m.y.) or more (Bethke, 1986b). Sediments are buried rapidly enough in these basins that strata cannot expel pore fluids at sufficient rates to accommodate normal compaction (Dickinson, 1953). As deep strata in the Illinois basin compacted, overpressures probably did not develop because of the low burial rate of ≤30 m/m.y. (98 ft/m.y.), its low shale content of <10% in deep strata, and the widespread sandstone aquifers with relatively high permeabilities (Figure 10).

Flow Driven by Topographic Relief

The second paleohydrologic model simulates groundwater flow set up by Mesozoic (or latest Paleozoic) uplift of the Pascola arch in the southern basin. The Pascola arch (Figure 13), located between the Ozark uplift and the Nashville dome, can be compared in size to the present-day Black Hills. Uplift caused as much as 4.5 km (14,763 ft) to be eroded from Paleozoic strata, and brought the most basal aquifers in the Illinois basin to the sub-Upper Cretaceous erosional surface. The Upper Cretaceous Tuscaloosa Formation in Kentucky and Tennessee contains erosional debris from the arch, including cobbles of chert from Mississippian carbonates and pebbles of Cambrian sandstones (Marcher and Stearns, 1962). On the basis of the sizes of sediments shed from the arch, Marcher and Stearns conservatively estimated that the arch rose at least 300 m (984 ft) above the surrounding topography.

The Pascola arch, because of its relief and the permeable aquifers exposed at its crest, probably served to recharge a regional flow system in which groundwaters flowed northward through the Illinois basin. Flow also may have been driven in part by the relief resulting from sediments shed from the Alleghenian orogen (Beaumont et al., 1988, their Figure 15). The LaSalle anticlinal belt, Mississippi River arch, and Ozark dome likely focused at least some of the flow northward across central Illinois (Bethke, 1986a). Bethke (1986a) proposed that this hydrologic system formed the hydrothermal zinc-lead ores of the upper Mississippi Valley district along the basin's northern margin.

The flow regime probably persisted until the Late Cretaceous downwarp of the Mississippi embayment (Stearns and Marcher, 1962). The regime flowed counter to present-day flow in deep strata: deep groundwaters currently flow southward and westward due to Quaternary incision of the Ohio and Mississippi rivers (Bond, 1972). The Mesozoic regime might be compared to modern groundwater flow in the Dakota aquifer system of South Dakota. Groundwater there recharges in and near the Black Hills and discharges hundreds of kilometers east under the Missouri River drainage (Darton, 1909; Bredehoeft et al., 1982).

We modeled Mesozoic groundwater flow along a cross section extending 700 km (434 mi) from the Pascola arch through the Fairfield basin and then northward to the flank of the Wisconsin arch (Figure 14). The cross section is a simplification of the basin's Cambrian through Pennsylvanian stratigraphy (Table 2).

The section crosses the Cottage Grove fault system,

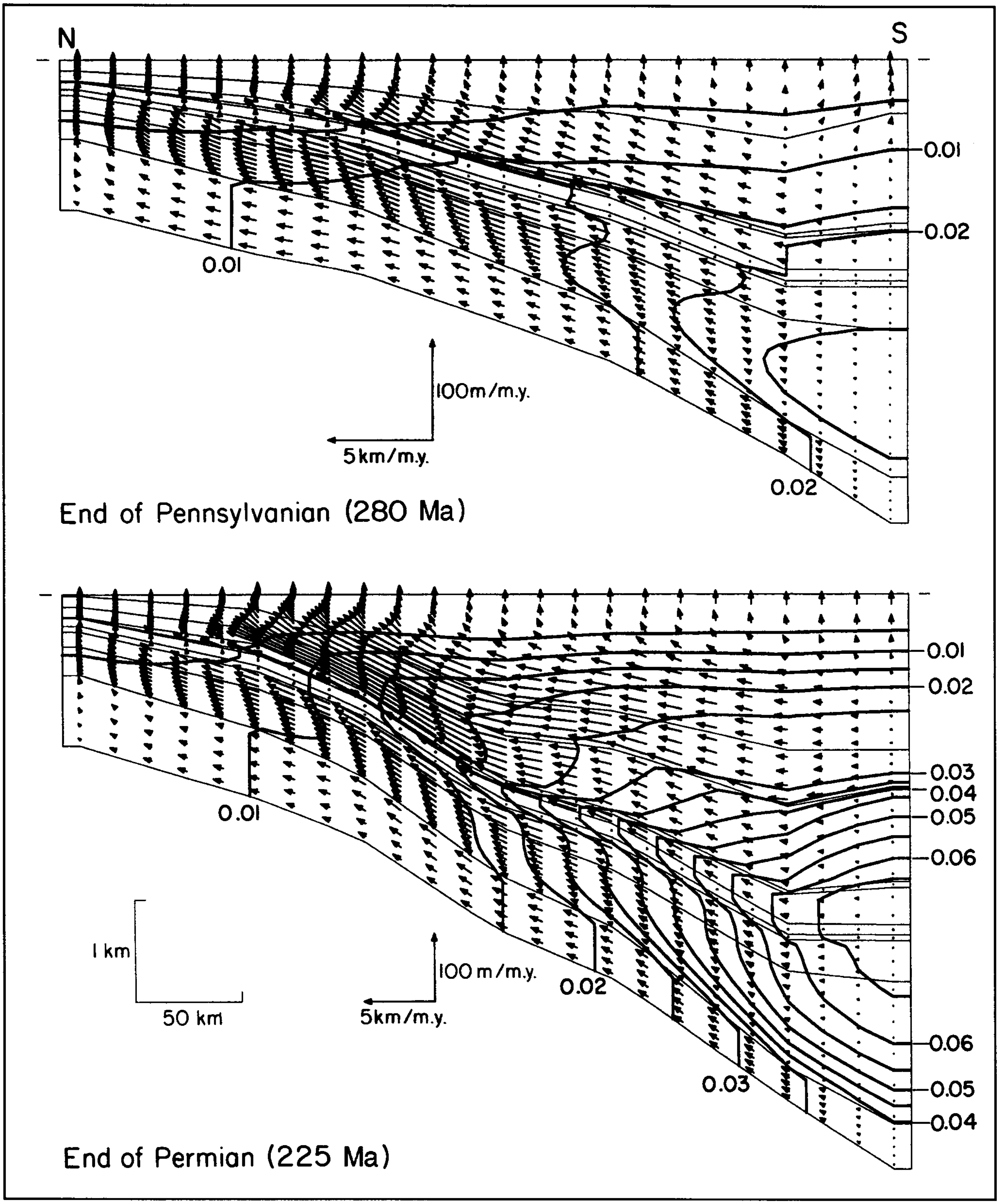

Figure 12—Calculated compaction-flow regime in Illinois basin at the ends of the Pennsylvanian and Permian, respectively, assuming past deposition of 1.5 km (1 mi) of Permian sediments. Arrows show groundwater velocity relative to the medium. Dark lines are equipotentials relative to hydraulic potential at the basin surface (MPa≈10 atm) showing the excess pressures that result from sediment compaction.

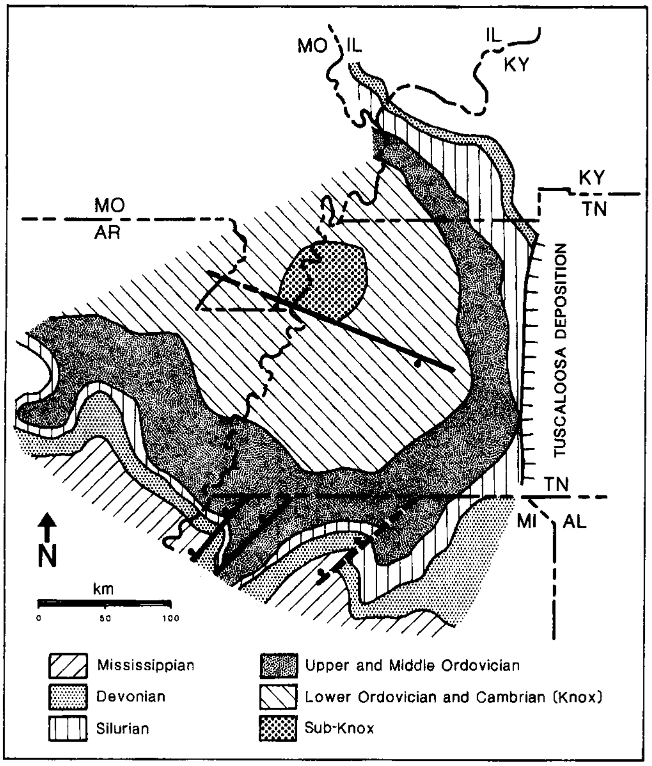

Figure 13—Sub–Upper Cretaceous subcrop map showing erosional surface of Pascola arch and area of Tuscaloosa deposition (after Schwalb, 1982). Upthrown sides of faults are marked.

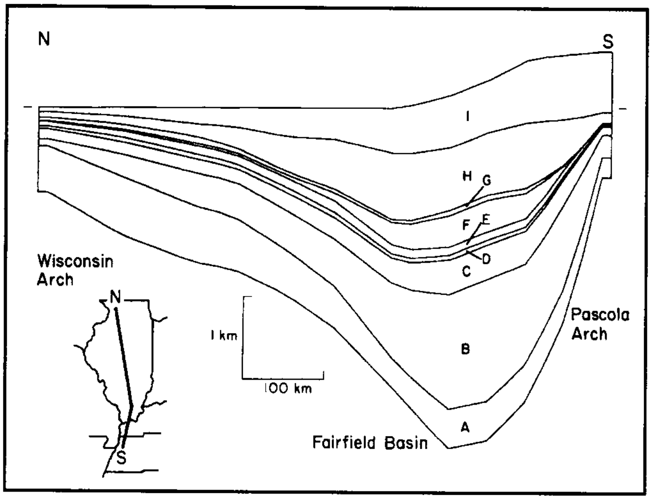

Figure 14—Cross section used for calculations of Mesozoic groundwater flow. Section extends 700 km (434 mi) from the past position of the Pascola arch northward through the Fairfield basin to the flank of the Wisconsin arch. Chronostratigraphic units are described in Table 2.

an east-west–trending structural feature in southern Illinois and western Kentucky (Figure 2), and the Lusk Creek fault zone, which forms the northwest boundary of the Reelfoot rift (see Buschbach and Kolata, in press; Nelson and Kolata, in press). The degree to which faults affect groundwater flow depends on the amount of gouge in the fault plane and whether aquifers become juxtaposed with aquitards. The amount of fault gouge depends primarily on the shale content in surrounding strata and the stress normal to the fault plane (Weber, 1986). The deep strata contain little shale, and it seems unlikely that fault motion affected the continuity of the thick basal aquifers. Fault movement was primarily strike-slip in the Cottage Grove fault zone, and rift-related movement along Lusk Creek fault zone occurred before the basal aquifers were deposited. For these reasons, we assume that flow on a regional scale could traverse the fault zone.

Flow velocities and hydrodynamic driving forces depicted by the flow model depend proportionately on the estimate of past topographic relief across the basin. Furthermore, even if relief could be determined exactly, the velocities predicted by the model might be understated because of the likelihood that deep strata have permeabilities that on regional scales exceed those determined by well tests (e.g., Garven, 1986). Hence, the hydrologic modeling is useful for gauging the magnitudes of past flow rates and driving forces only to within the uncertainties involved in estimating past relief and aquifer permeabilities.

In calculating the model shown in Figure 15, we assumed that the arch rose 700 m (2296 ft) above the northern basin, giving an average northward slope of 1‰. This value is somewhat greater than Marcher and Stearn's (1962) 300 m (984 ft) estimate of the minimum relief on the arch, which they termed conservative, and comparable to the Permian relief implied by Beaumont et al.'s (1988) calculations. We also report hydrodynamic drives that result from assuming lesser and greater past relief (Table 3).

Figure 15 shows the results of simulating groundwater flow in the Mesozoic. Topographic relief across the basin drives groundwater at rates of about 1–2 m (3–6.5 ft) per year through the deep aquifer complex in Cambrian and Ordovician strata. Groundwater flow rates in the overlying Silurian through Mississippian strata vary depending on lithology, but in several units reach about 5 m/yr (16 ft/yr). The potential gradient in Ordovician through Mississippian strata that contain the main source rocks and most petroleum reservoirs in the basin reflects the topographic relief on the water table. The calculated gradient $d\Phi/dl$ through these strata is about 0.03 MPa/km (0.5 atm/mi). Throughout the basin, flow rates induced by the topographic relief were several orders of magnitude more rapid than those indicated (Figure 12) for compaction-driven flow.

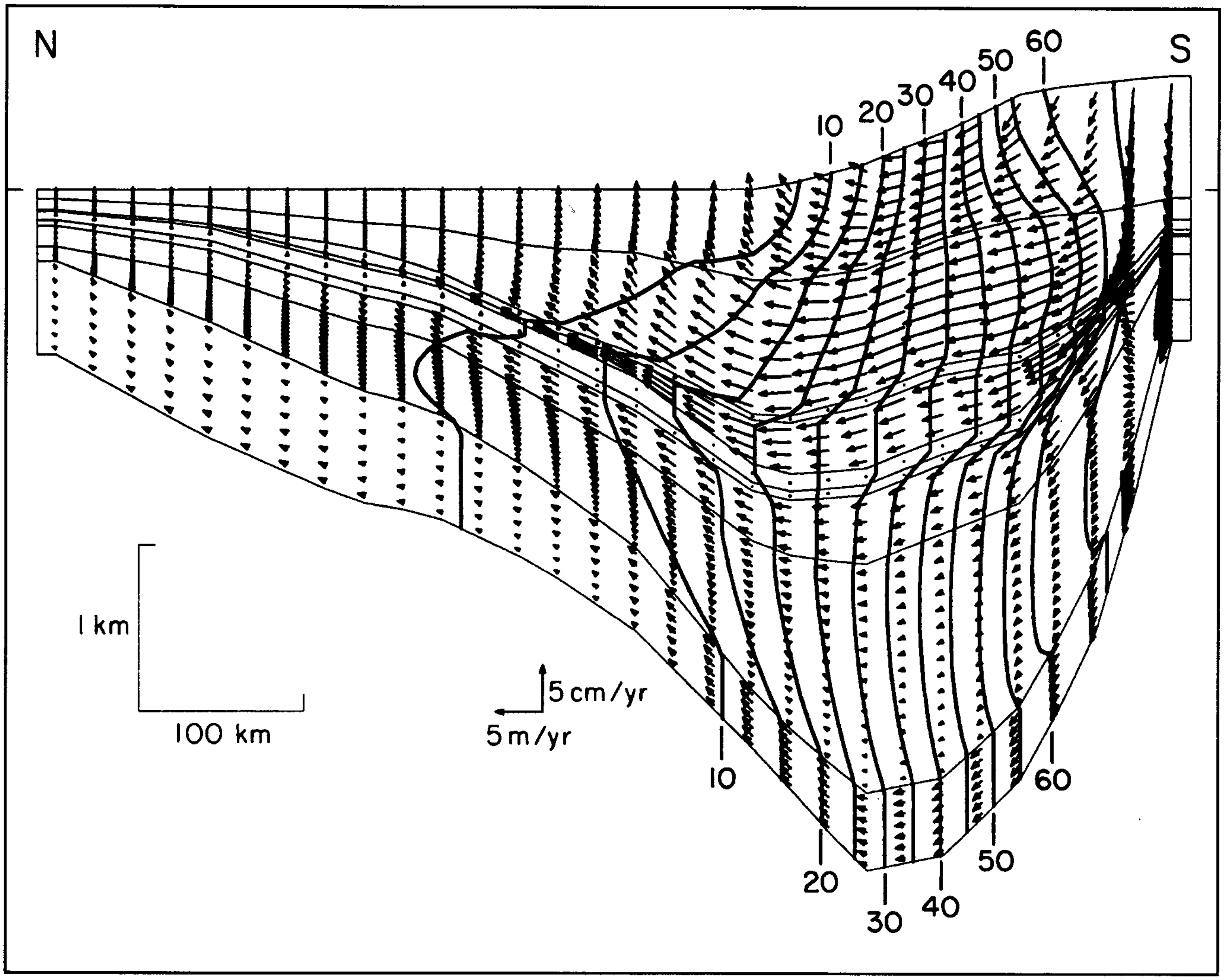

Figure 15—Calculated groundwater flow regime resulting from uplift of Pascola arch in the Mesozoic or latest Paleozoic. Dark lines are equipotentials (MPa, relative to atmospheric pressure at sea level) showing the drive for groundwater flow resulting from topographic relief across the basin.

CONTROLS ON PETROLEUM MIGRATION

Over the past decade, most geologists have come to agree that petroleum migrates along carrier beds from source rock to reservoir as a separate phase that is largely immiscible with groundwater (e.g., Tissot, 1987). The most direct evidence supporting this conclusion is that compounds within families such as the *n*-alkanes (except for small carbon number *n* chains, which diffuse readily and can exsolve as gas) are present in similar proportions in source rocks, along migration pathways, and in reservoirs. Because the compounds of varying molecular weight are differentially soluble in water, their proportions would fractionate if the oil migrated in an aqueous solution. In fact, the lack of fractionation among oil components during migration allows oils to be correlated with their source rocks geochemically (e.g., Figures 6 and 7).

A complete description of oil migration, then, accounts not only for the hydrodynamic factors already discussed, but the buoyant and capillary forces that act on the immiscible phase. Assuming that oil density remains constant, an adequate approximation for this paper, oil, like groundwater, has a hydraulic potential that represents its mechanical energy per unit volume (Hubbert, 1953). The potential

$$\Phi_o = P_o - \rho_o g z,$$

reflects the cumulative work required to bring the oil to pressure P_o and carry it to depth z. The pressure P_o on the oil phase in a porous rock generally exceeds the water pressure P by the capillary pressure P_c, so that $P_o = P + P_c$. Hence, the hydraulic potential of oil differs from that of water in the same rock because of oil's lesser density (commonly 0.6–0.7 g/cm^3) (England et al., 1987) and its capillary pressure. Capillary pressure is the additional pres-

Table 3. Estimated Driving Forces for Migration*

	E (kPa/km)	(atm/mile)
Paleozoic compaction**	0.03	0.0005
Mesozoic topography†		
300 m relief	10	0.2
700 m relief	30	0.5
1000 m relief	40	0.7
Buoyancy‡	20	0.3

*Calculated from equations (4) and (5).
**From results in Figure 12.
†From results in Figure 15.
‡Assuming, $\rho - \rho_o = 0.4$ g/cm^3, and a carrier bed slope of 0.5% (from Figure 2).

sure necessary to saturate the water-filled pore space of rock with increasing amounts of oil, which in the great majority of cases has a smaller surface tension than water. Capillary pressure rises as oil is introduced because the oil must displace water from areas with progressively higher capillary forces (such as narrow pore throats) to achieve further saturation. Berg (1975) and Jennings (1987) detailed measuring and interpreting capillary pressure measurements. The trend of capillary pressure reflects the grain size, compaction, cementation, and heterogeneity of the rock, as well as its internal connectivity and roughness. Capillary pressures are lower where pore throats are broad, and rise steeply with increasing saturation in poorly sorted or unevenly cemented rocks.

The oil discharge q_{ol} along a direction l is the volume of oil that crosses a unit area of the carrier bed per unit of time. Discharge is given by

$$q_{ol} = -\frac{k_l k_{ro}}{\mu_o} \frac{d\Phi_o}{dl}$$

(Peaceman, 1977). Here, k_l is permeability along the carrier bed, μ_o is the oil's viscosity, and k_{ro} is relative permeability to the oil phase, which ranges from 0–1. Relative permeability describes the mobility of the rock's oil phase, which depends on the distribution of oil within the rock's pore space. At small saturations, the oil forms discrete globules in the centers of pores of a water-wet rock (Leverett, 1941) so that oil is immobile. If enough oil saturates the rock to form an interconnected network through the pore space, however, oil is mobile and k_{ro} is not zero. The minimum saturation to achieve mobility is the rock's irreducible oil saturation because it cannot be recovered once introduced to the rock. Hence, the irreducible saturation of carrier beds exacts an inevitable loss of oil during migration.

Forces Driving Migration

Oil migrates in response to hydrodynamic, buoyant, and capillary driving forces. The magnitudes of the forces that act to drive migration can be derived from the flow equations presented in the previous section (Hubbert, 1953). Mechanical work is the product of force applied on an object and the distance the object traverses. Because hydraulic potential is the cumulative work applied to move a volume of fluid to a given position, the force driving flow along a direction l is the negative gradient $-d\Phi_o/dl$ in that direction (Hubbert, 1940).

The hydraulic potential of an oil phase Φ_o can be written in terms of hydraulic potential for water Φ,

$$\Phi_o = \Phi + (\rho - \rho_o)\,gz + P_c$$

by combining equations 1, 2, and 3. The hydrodynamic, buoyant, and capillary driving forces along a direction l, then, are given

$$E = -\frac{d\Phi_o}{dl} = E_b + E_b + E_c\,,$$

where

$$E_b = -\frac{d\Phi}{dl}\,, \qquad (4)$$

$$E_b = -(\rho - \rho_o)\,g\frac{dz}{dl}\,, \qquad (5)$$

$$E_c = -\frac{dP_c}{dl}\,.$$

The driving forces work to move oil to areas of lesser hydraulic potential of water, depth, and capillary pressure.

Using the results of the hydrologic simulations already presented, we estimated the magnitudes of the hydrodynamic forces that acted during basin compaction and the Mesozoic flow system as well as the buoyant drives along the inferred migration pathways. The resulting forces are given in Table 3.

Efficiency and Velocity of Migration

The process responsible for long-range migration must be sufficiently efficient so that the oil is not dissipated as irreducible saturation within the carrier bed, and rapid enough to allow oil to reach distal reservoirs during the interval of migration. In this section, we argue that migration efficiency and velocity are greatest when the oil flows through only a small fraction of the carrier bed.

The efficiency of oil migration through a carrier bed is the ratio of the amount of oil that reaches traps or discharges from the bed to the amount that remains in the bed's pore space as irreducible saturation. A significant amount of oil may be required to achieve irreducible saturation in a sediment. England et al. (1987), for example, tested various sandstones and found that the saturations required for oil to flow ranged from 18 to 91%; the

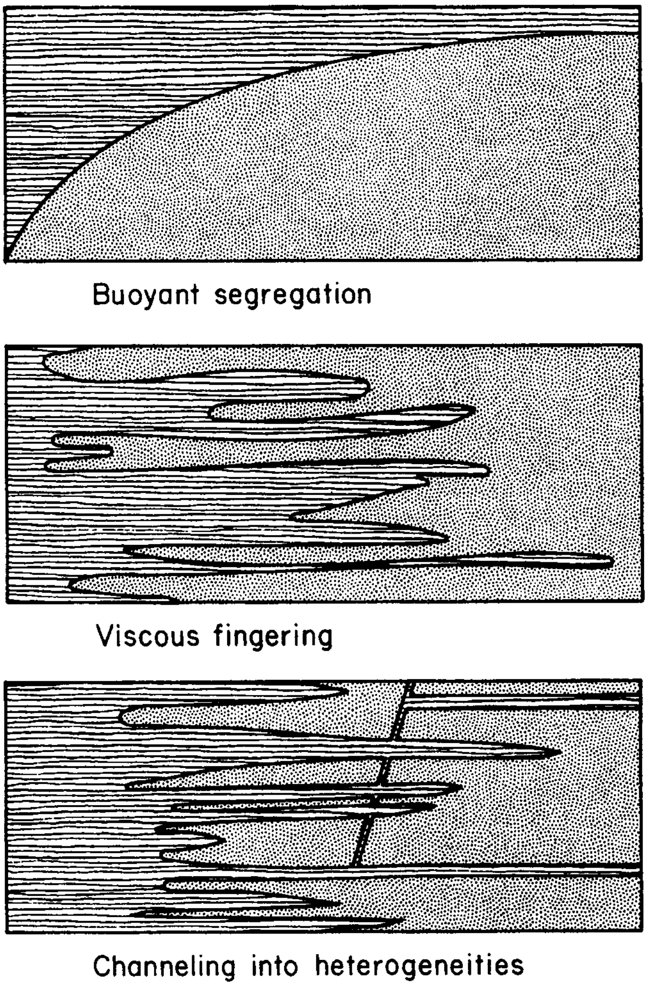

Figure 16—Origins of heterogeneous oil saturations in carrier beds shown schematically for oil moving from left to right from a hypothetical homogeneous distribution (Bethke, 1989). Horizontal lines indicate no oil, stipple indicates oil-saturated carrier beds.

average value in these tests was about half of the pore volume of the rock. Studies that balance the volumes of oil generated in source rocks with the amount that could be lost to irreducible saturation during migration (e.g., England et al., 1987) indicate that oil must migrate through only a small fraction of the carrier bed. If the entire bed served as a migration pathway, vast quantities of oil would remain within the bed's pore structure. The loss of oil in this latter case would be sufficient to preclude migration over long distances.

Migration is most rapid when oil moves through a small fraction of the carrier bed. A single fluid flowing through an aquifer at a given rate of discharge moves at a velocity that varies inversely with the aquifer's porosity. In other words, at a given rate of discharge, fluid traverses greater distances through rocks of lower porosity. Groundwater, for example, moves rapidly through fractured granites even at modest discharge rates because the fraction of the rock occupied by connected pore space (the fractures) is very small.

By the same principle, the velocity of petroleum migration depends on the fraction of the carrier bed through which the oil is mobile. Migration is most rapid when the oil moves through a saturated pathway that occupies a small part of the carrier bed. Consider a carrier bed of which a fraction f_o is sufficiently saturated to allow oil to flow. If the total discharge per unit width is $Q_o = bq_o$, where q_o is the average oil discharge and b is the bed thickness,

$$v_o = \frac{Q_o}{f_o \phi b S_o}.$$

S_o is the average oil saturation where oil is mobile. For a given discharge rate Q_o, the velocity of migration increases with decreasing porosity, carrier bed thickness, irreducible oil saturation, and the fraction f_o of the bed carrying the flow.

Heterogeneous oil saturations can develop within a carrier bed by several processes (Figure 16), including buoyant segregation, viscous fingering, and channeling into the bed's irregularities by capillary forces. As discussed in a following section, we believe that capillary channeling was important in controlling carrier bed saturation during long-range migration in the Illinois basin. Figure 17 illustrates the capillary driving forces that act on oil within a carrier bed. If a carrier bed were perfectly homogeneous, capillarity would work to equalize saturation (arrow 1, Figure 17). In a heterogeneous bed, however, local gradients in capillary properties produce a stronger control on oil saturation. Arrow 2 (Figure 17) illustrates the drive from fine to coarse-grained laminae within the bed. Oil preferentially occupies the laminae with the broadest pore apertures, even if these laminae make up only a small fraction of the rock.

Capillary pressures in macroscopic fractures, vuggy pores, and karst channels are negligible. Capillarity drives oil into such openings (arrow 3, Figure 17) regardless of the oil saturation within the open space. Hence, heterogeneities in carrier beds, whether fractures, irregularities in grain size, or karst features, can work to concentrate the oil saturation in a relatively small fraction of the bed, permitting efficient and rapid migration.

DISCUSSION

The tectonic and hydrologic framework within which petroleum migrates has been a subject of controversy at least since Munn (1909) proposed that groundwater flow plays a role in the migration of petroleum and its accumulation into reservoirs. Many studies of both actively subsiding (e.g., Athy, 1930) and ancient (e.g., Vigrass, 1968) basins have emphasized the role of sedi-

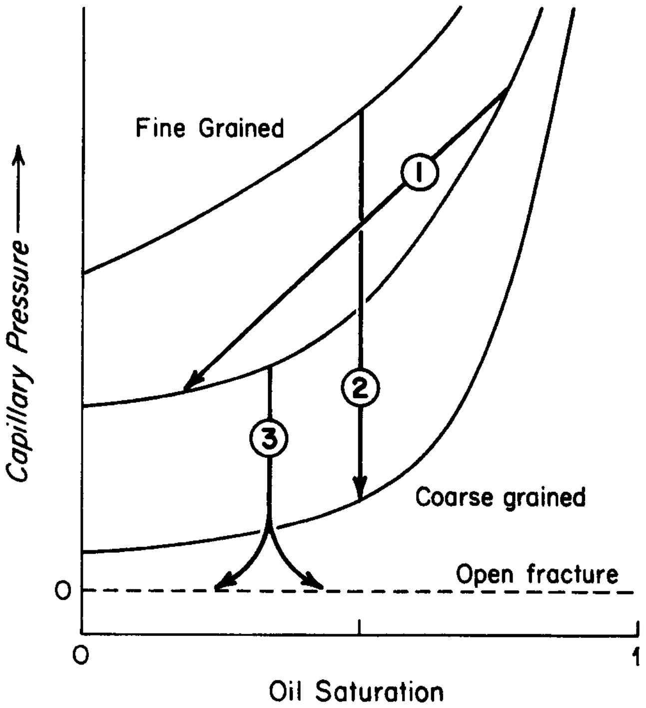

Figure 17—Driving forces for oil migration arising from capillary effects. (1) Drive toward less-saturated areas within bed of uniform grain size. (2) Drive for migration from fine-grained to coarse-grained rocks. (3) Drive from sediment into an open fracture, regardless of saturation within the fracture.

ment compaction in providing the drive for petroleum migration. Other studies (e.g., Rich, 1921; Hubbert, 1953; Tóth, 1980; Garven, 1989) considered that regional groundwater flow set up by topographic relief across basin surfaces drives oil migration. Rich (1921, 1931), for example, considered compaction-driven flow to be subordinate to artesian flow arising from head differences across the basin in driving migration through carrier beds.

Other workers (Salisbury, 1968; Oliver, 1986) suggested that thrust faulting or tectonic compression could drive migration. Berry (1973) attributed the high hydraulic potentials in the California Coast Ranges to lateral tectonic compression, and Ge and Garven (1989) investigated fluid flow in compressional tectonic environments. The Illinois basin as a whole, however, has not undergone compressive orogeny on a large scale nor been subject to major thrust faulting; presumably compression has not been important in driving migration in the basin.

Role of Sediment Compaction

In his study of shale porosity in northern Oklahoma, Athy (1930, p. 25) concluded that "the primary cause of the movement of oil from a shale source bed to reservoir is compaction within the shale beds." This concept has provided the basis for many subsequent studies (e.g., Magara, 1976; Bonham, 1980). Magara (1976, p. 543), for example, assumed that "water expulsion due to compaction of sediments is the most important factor in causing hydrocarbons to migrate from source rocks to reservoirs." Indeed, compaction likely drives migration in actively subsiding basins such as the Gulf of Mexico, where rapid sedimentation maintains geopressures (Bethke et al., 1988) and oil is currently observed to be migrating near modern depocenters (Nunn and Sassen, 1986).

Sediment compaction is unlikely to have played a role in migrating oil within the Illinois basin. First, as has been discussed, sediment compaction only slightly increased the hydraulic potentials of deep groundwaters and, hence, provided little hydrodynamic drive for oil migration. Even though the migration pathway from source to reservoir in the Illinois basin was nearly horizontal, so that buoyancy operated in a direction almost normal to flow, the predicted hydrodynamic drive is several orders of magnitude smaller than the estimated buoyant drive (Table 3).

The small potential gradients and hydrodynamic drives given by the calculation (Figure 12) reflect the low sedimentation rates and high aquifer permeabilities characteristic of intracratonic basins. We were somewhat uncertain about the permeabilities chosen for the simulation because permeabilities on regional scales can differ from those measured in well tests, such as those in Figure 10. Regional scale permeabilities generally are greater than those measured on local scales because the former account for heterogeneities such as large-scale fracture networks (e.g., Garven, 1986). Accounting for the scale effect, then, would lead to smaller predicted hydraulic potentials and, thus, even less hydrodynamic drive in the compacting basin.

These results imply that oil is unlikely to have migrated in response to dewatering of deep overpressured zones (e.g., Sharp, 1978) because overpressures such as those characteristic of the Gulf of Mexico basin do not develop in the paleohydrologic reconstructions of the Illinois basin. This conclusion might be extended to include other North American basins that have hosted long-range migration, such as the Williston, Denver, and Western Canada, and Appalachian foreland basins because these basins also contain basal aquifer complexes and underwent slow burial.

The timing of oil generation in the basin also argues against sediment compaction having played a role in driving long-range migration. Due to its shallow burial under relatively cool conditions, the New Albany Group began to generate oil late in the basin's history (Cluff and Byrnes, in press). Figure 18 shows the timing of oil generation calculated assuming various past geothermal gradients. At geothermal gradients of 30°C/km (1.65°F/100 ft) or less, the New Albany began to generate oil in the central basin during the Late Permian. Thus, the interval of generation began after the New Albany and most or all of the overlying strata had been deposited and compacted. Oil could have been produced earlier if geothermal gradients in the late Paleozoic were greater than 30°C/km (1.65°F/100 ft). In this case, however, oil would had to have migrated during the time interval after generation began but before sedimentation ceased; if this interval existed, it probably was short.

Role of Topographic Relief

Oil is more likely to have migrated over long distances through the Illinois basin during the Mesozoic in an environment of northward groundwater flow. The post–Early Permian and Mesozoic flow regime (Figure 15), set up by uplift of the Pascola arch in the southern basin, provided a stronger driving force for migration than the earlier Paleozoic regime of compaction-driven flow. From the calculations in Table 3, topographic relief drove migration with a force about equivalent to that estimated for the component of buoyant force acting along the migration pathway. In addition, oil was actively being generated in the New Albany Group (Figure 18) (Cluff and Byrnes, in press) during the Permian–Mesozoic flow regime, providing for an explanation of migration consistent with the timing of oil generation.

The estimated hydrodynamic and buoyant driving forces for migration (Table 3) are nearly equal, so that the dominant drive cannot be determined within the uncertainty of the calculations. Other oils in the basin, such as those found in younger strata nearer the central basin, likely migrated along steeper pathways than the oils considered in this study, and hence experienced greater buoyant forces than those calculated here.

Hydrodynamic and buoyant drives act on oil in fundamentally different ways. Whereas hydrodynamic drives act to move oil in the direction of decreasing hydraulic potential, which commonly is laterally along deep aquifers, buoyancy can act only to drive oil along pathways with an upward vertical component. A regional hydrodynamic drive likely would play a major role in aiding long-range migration by sweeping hydrocarbons past irregularities in the slopes or capillary structures of carrier beds. We doubt that the carrier beds, which dip by an average of only 0.5%, have a sufficiently regular structure over the scale of tens of kilometers to allow oil to migrate under the influence of buoyancy alone. Oil migrating by its buoyancy might pond in widespread regions where the slopes of carrier beds are small rather than reach traps to form economic reservoirs. Although some studies (e.g., Davis, 1987) suggested that hydrodynamic drives generally can be taken as subordinate to buoyancy, we stress the importance of considering hydrodynamic forces in driving migration along the nearly horizontal carrier beds within cratonic basins.

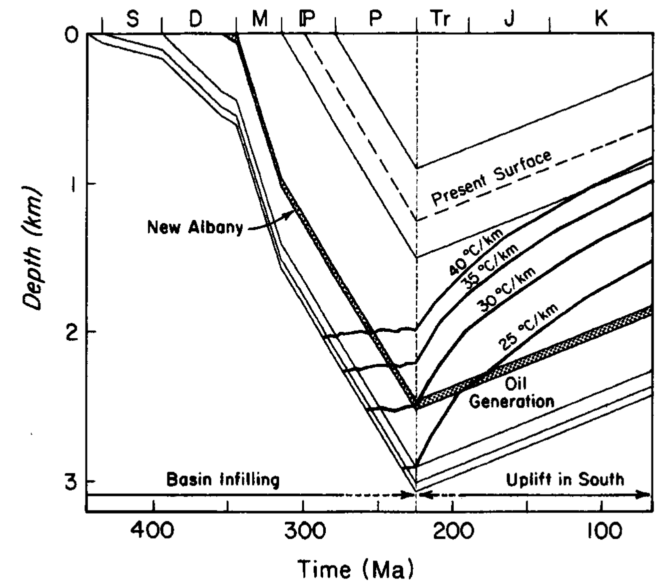

Figure 18—Burial history reconstruction of the New Albany Group (shaded) showing calculated time when the group became thermally mature. Dark lines show onset of sufficient thermal maturity for oil generation, assuming past geothermal gradients of 25, 30, 35, and 40°C/km (1.35, 1.65, 1.9, and 2.2°F/100 ft). The oil window for each geothermal gradient is the area below the corresponding line. Calculations were made using Lopatin's method (Waples, 1980).

Carrier Beds for Long-Range Migration

A remaining problem is identifying the carrier beds through which the oil migrated to reach the outlying reservoirs. Because the New Albany–sourced oils are found today in reservoirs within the Niagaran series of the Silurian, they must have migrated either downward out of the New Albany, or upward and then across a fault plane into older strata.

The most suitable beds for carrying long-range migration are probably the Devonian and Silurian strata that lie beneath the New Albany. As described previously, petroleum migrates most efficiently and rapidly through thin beds or strata with heterogeneous capillary structures such as fractured rocks or karstic limestones. The Upper Devonian Sylamore Sandstone, which is immediately below the source beds of the New Albany Group, is sporadically present in central and western Illinois (Wilman et al., 1975). The sand rarely is more than 1.5 m (5 ft) thick and generally just a few centimeters thick, making it a candidate for carrying oil (Oltz and Crockett, 1989).

Immediately underlying the Sylamore is a widespread unconformity that merges with the sub-Kaskaskia unconformity near the basin margins (Figure 19). Strata beneath the unconformity include carbonate and cherty carbonate rocks of the Middle Devonian as well as lime-

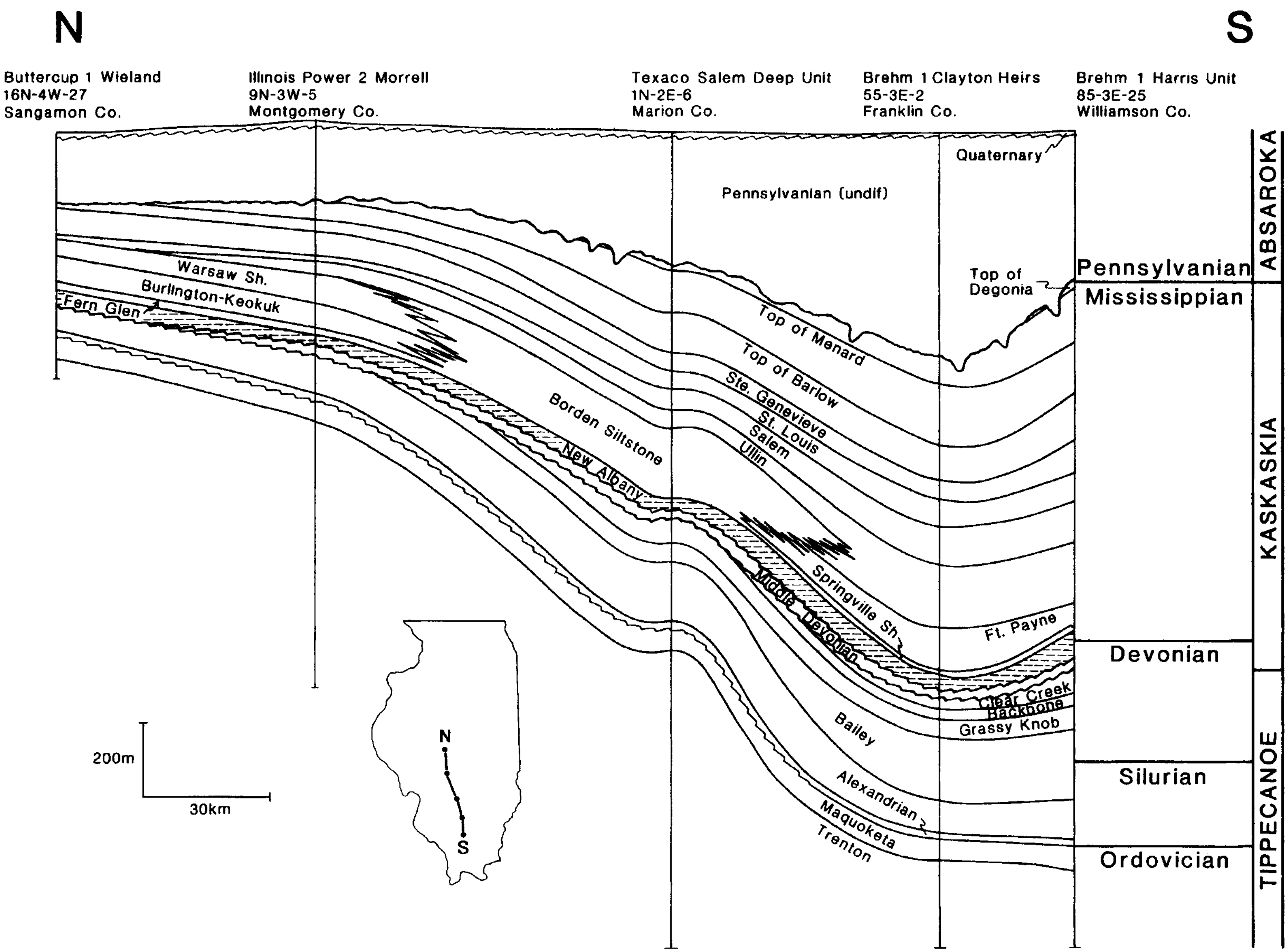

Figure 19—Structural cross section from the deep Illinois basin to the area of production from Silurian reservoirs showing strata surrounding the New Albany Group (drawn by S. T. Whitaker, after Whitaker, 1988). Cross section shows Tippecanoe (Ordovician) and higher strata plotted relative to the present surface. Line of section is shown in inset. Wavy lines indicate positions of erosional unconformities, including the sub-Kaskaskia unconformity at the base of Middle Devonian strata. Cross section is constructed from data from wells in (south to north) Williamson, Franklin, Marion, Montgomery, and Sangamon Counties.

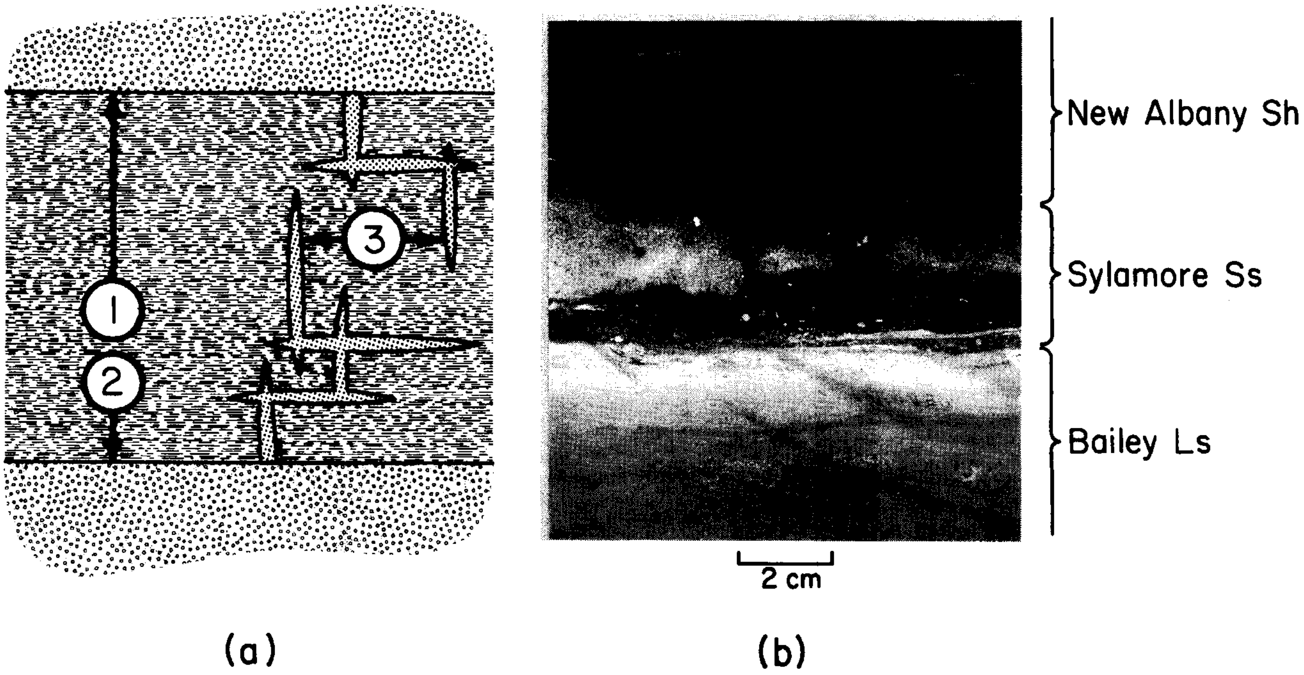

Figure 20—Primary migration from a petroleum source bed into surrounding carrier beds. (a) (1) Flow driven through the sediment matrix or its microfractures by the combined effects of buoyancy, capillary effects, and internal pressures generated within the source bed. (2) Flow driven downward against buoyant forces by gradients in capillary and internal pressures. (3) Migration into macroscopic fractures in response to capillary and pressure gradients. (b) Photograph of a core sample of the Sweetland Creek Member of the New Albany Group, a thin stringer of the Sylamore Sandstone (Upper Devonian), and the Bailey Limestone (Lower Devonian). Core is from Tom Doran 1 Koch well in Washington County (Sec. 34, T15, R5W), Illinois, at 648.2 m (2126.6 ft) depth. Photograph shows oil saturation in the New Albany source and Sylamore carrier beds.

stones and dolomites of the Niagaran Series of the Silurian System (Figure 20). These strata were exposed to extensive weathering during the Devonian and are known to have developed extensive karst features along the Sangamon arch (Whiting and Stevenson, 1965). Weathered fractures and karst features are also observed in samples from along the unconformity in more deeply buried areas. In addition, limestones along the unconformity have been extensively dolomitized, a process that has increased porosity and permeability. The outlying reservoirs described in this study produce from dolomite or karst porosity that in core samples sometimes resembles the vuggy porosity encountered in reefs (Whiting, 1956). The weathered and dolomitized limestones along the sub-Kaskaskia surface are perhaps the most attractive candidates for having carried the long-range migration.

CONCLUSION

The phenomenon of long-range petroleum migration in cratonic basins, sometimes over pathways 150 km (93 mi) or more in length, has been observed in a number of the interior basins in North America. However, the nature of migration processes, especially those operating over long distances, has been controversial for more than 80 yr. This study suggests that long-range migration in the Illinois basin occurred late in the basin's history during a Mesozoic period of regional groundwater flow. The northward flow regime was set up by tectonic uplift of the Pascola arch in the southern basin. The hydrodynamic drive for migration, which was comparable to the component of buoyant drive acting along the nearly horizontal migration pathways, aided migration by sweeping oil past irregularities in the dips of carrier beds where the oil otherwise might have accumulated in noneconomic quantities. Interestingly, only northward migration has been observed in the Illinois basin; virtually no economic reservoirs have been discovered south of the Cottage Grove fault zone, which extends westward from near the Rough Creek fault zone in southern Illinois (Figure 1) (Nelson and Krausse, 1981).

We believe that Devonian and Silurian limestones immediately underlying a widespread unconformity at the base of the New Albany Group carried much of the migrating oil to the reservoirs in Sangamon and Christian counties. Porosity in the limestones had been enhanced by weathering during the formation of sub-New Albany unconformities, and by dolomitization. Capillary forces within the beds would have segregated oil into weathered channels through which the oil migrated. Such segregation increases the efficiency and velocity of migration, helping explain the long distances traversed. We doubt that the oil migrated for long distances along faults. The central basin contains few fault systems, and none oriented along the inferred migration directions.

These results suggest that the nature of past migration in the Illinois basin, and by analogy in ancient basins within continental interiors, differs sharply from the migration currently occurring in actively developing basins along continental margins. In the Gulf of Mexico basin, for example, petroleum is generated concurrently with sedimentation, and oil migrates vertically upward along salt domes and the growth faults that develop in response to deep geopressuring (Rubey and Hubbert, 1959; Bruce 1973); a large fraction of the Gulf basin's most productive fields are associated with domes and growth fault complexes. Petroleum accumulation here is controlled, in part, by the distribution of geopressures (Fowler, 1970; Timko and Fertl, 1971). In contrast, significant lateral migration occurred in the Illinois basin. This basin generated oil late in its history, and developed neither geopressured zones nor growth faults during compaction. In each of these aspects, petroleum migration in the basins of cratonic interiors cannot be viewed as an ancient analog of the migration observed within basins along continental margins. Migration studies especially need to account for the high level of lateral hydrologic continuity within interior basins, the late timing of oil generation, and the tectonic histories of the arches, located along basin margins, whose movements affect basin hydrodynamics.

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