Material-balance assessment of the New Albany–Chesterian petroleum system of the Illinois basin

M. D. Lewan, M. E. Henry, D. K. Higley, and J. K. Pitman

ABSTRACT

The New Albany–Chesterian petroleum system of the Illinois basin is a well-constrained system from which petroleum charges and losses were quantified through a material-balance assessment. This petroleum system has nearly 90,000 wells penetrating the Chesterian section, a single New Albany Shale source rock accounting for more than 99% of the produced oil, well-established stratigraphic and structural frameworks, and accessible source rock samples at various maturity levels. A hydrogen index (HI) map based on Rock-Eval analyses of source rock samples of New Albany Shale defines the pod of active source rock and extent of oil generation. Based on a buoyancy-drive model, the system was divided into seven secondary-migration catchments. Each catchment contains a part of the active pod of source rock from which it derives a petroleum charge, and this charge is confined to carrier beds and reservoirs within these catchments as accountable petroleum, petroleum losses, or undiscovered petroleum. A well-constrained catchment with no apparent erosional or leakage losses is used to determine an actual petroleum charge from accountable petroleum and residual migration losses. This actual petroleum charge is used to calibrate the other catchments in which erosional petroleum losses have occurred. Petroleum charges determined by laboratory pyrolysis are exaggerated relative to the actual petroleum charge. Rock-Eval charges are exaggerated by a factor of 4–14, and hydrous-pyrolysis charges are exaggerated by a factor of 1.7. The actual petroleum charge provides a more meaningful material balance and more realistic estimates of petroleum losses and remaining undiscovered petroleum. The total petroleum charge determined for the New Albany–Chesterian system is 78 billion bbl, of which 11.4 billion bbl occur as accountable in place petroleum, 9 billion bbl occur as residual migration losses, and 57.6 billion bbl occur as erosional losses. Of the erosional losses, 40 billion bbl were lost from two catchments that have highly faulted and extensively eroded

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sections. Anomalies in the relationship between erosional losses and degree of erosion suggest there is potential for undiscovered petroleum in one of the catchments. These results demonstrate that a material-balance assessment of migration catchments provides a useful means to evaluate and rank areas within a petroleum system. The article provides methodologies for obtaining more realistic petroleum charges and losses that can be applied to less data-rich petroleum systems.

INTRODUCTION

Describing oil accumulations in the context of petroleum systems has been highly popularized in recent years (Magoon and Dow, 1994). Although this approach provides a means of conceptualizing the essential elements and processes responsible for discovered oil accumulations, it is not sufficient by itself to evaluate quantities of undiscovered oil (Otis and Schneidermann, 1997). One approach to quantifying petroleum systems is through a material-balance assessment, which requires determining petroleum charges and losses. Charge is the quantity of oil expelled from a volume of mature source rock, which is referred to as a hydrocarbon kitchen (Demaison, 1984) or pod of active source rock (Magoon and Dow, 1994). Losses are the quantities of petroleum lost from the system as a result of surface leakage, eroded section, or secondary-migration residual. The ultimate in place petroleum of a system is the difference between charge and losses (Figure 1A). Subtracting accountable in place petroleum from ultimate in place petroleum gives the quantity of undiscovered petroleum remaining in a system (Figure 1B). Conceptually, this quantity of undiscovered in place petroleum includes conventional and unconventional petroleum, which is the decisive criterion in ranking and assessing petroleum systems.

Various renditions of this material-balance approach have been employed to estimate undiscovered petroleum on a global scale (e.g., Miller, 1992; Hunt, 1996), within basins (e.g., Neruchev, 1964; Conybeare, 1965; McDowell, 1975; Goff, 1983; Kontorovich, 1984; Cornford, 1993), for prospect evaluations (e.g., Sluijk and Nederlof, 1984), and in assessing accumulations (e.g., Trask, 1936; Bishop et al., 1983; Riediger, 1994;). Although the input for all of these methodologies is essentially the same as that shown in Figure 1, the high uncertainty in obtaining realistic petroleum charges and losses (Charpentier et al., 1995) has rendered them inconclusive and their utility debatable. To develop this approach and establish realistic quantities for petroleum charges and losses, a well-constrained petroleum system is needed to minimize uncertainties. Requirements for such a petroleum system included an extensive drilling history, proven source rock to oil correlations, established subsurface geological framework, well-defined pod of active source rock, and little or no remaining undiscovered petroleum.
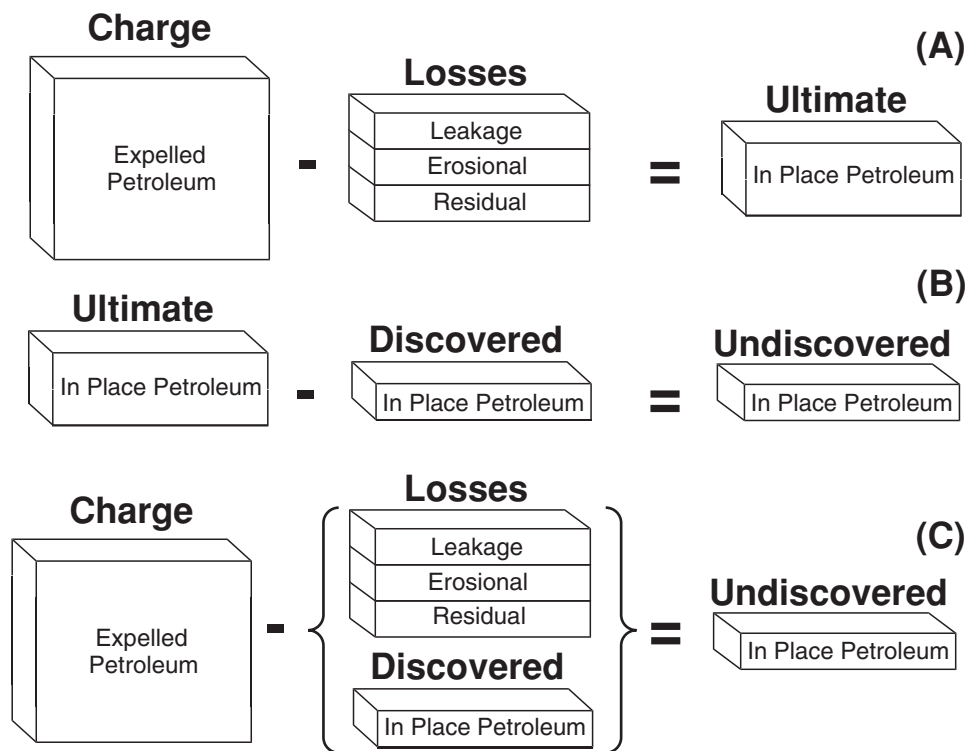
Figure 1. General pictorial of material-balance expressions describing (A) ultimate in place petroleum, (B) undiscovered in place petroleum, and (C) summation of expressions A and B.

The New Albany–Chesterian petroleum system of the Illinois basin meets these requirements, with approximately 90,000 wells penetrating the Chesterian section (Petroleum Information Corporation, 1996), more than 99% of the produced oil being correlated to the New Albany Shale (Hatch et al., 1990), numerous cross sections and isopach maps of key horizons (Swann and Bell, 1958; Hasenmueller and Comer, 1994), available subsurface samples of New Albany Shale ranging from immature to overmature (Frost, 1980; Robl et al., 1983; Hasenmueller and Leininger, 1987), and a 50% probability of only an additional 6.1 million bbl of recoverable oil remaining in undiscovered accumulations greater than 1 million bbl (Macke, 1996). This last attribute is especially important because it allows the quantity of undiscovered petroleum to be initially set to zero, which reduces the number of unknowns to be determined in obtaining realistic quantities of petroleum charge and losses (Figure 1C). Another important attribute of this system is the predominance of oil over gas (gas to oil ratio = 750 ft^3/bbl [Macke, 1996]), which focuses the material-balance assessment on one petroleum phase (i.e., oil) rather than on two phases (i.e., oil and gas).

The objective of this article is to present a methodology for quantifying the New Albany–Chesterian petroleum system through a material-balance approach. As a result of this quantification, more realistic magnitudes and key controls for petroleum charges and losses are established. We anticipate that as this approach is further developed in other data-rich petroleum systems, more quantitative concepts will improve risking and assessing undiscovered petroleum in less data-rich systems.

PETROLEUM SYSTEM SETTING

The New Albany–Chesterian petroleum system of the Illinois basin extends across Illinois, southwestern Indiana, and western Kentucky. As shown in Figure 2, the system is bordered by the Kankakee arch, Cincinnati arch, and Sangamon arch, and dissected by the Cottage Grove, Rough Creek/Shawneetown, Fluorspar area, Wabash, and Pennyrile fault systems. This petroleum system is defined by source rocks in the New Albany Shale (Devonian–Mississippian) and oil accumulations in reservoir rocks ranging in age from Silurian through Pennsylvanian (Figure 3). Approximately 60% of the produced oil comes from reservoirs in the Chesterian Series (Upper Mississippian), which consists of nonmarine, lenticular, quartz-rich sandstone. The system spans a period of about 225 m.y., starting from the Late Devonian through the Late

Figure 2. Illinois basin index map showing outline of basin (purple dashed line [Buschbach and Kolata, 1990]), major structural features (red lines; CGFS = Cottage Grove fault system, RC-SHN FS = Rough Creek–Shawneetown fault system, FAFS = Fluorspar Area fault system, WVFS = Wabash Valley fault system, PRFS = Pennyrile fault system [Nelson, 1990]), and extent of Chesterian rocks (yellow area [Treworgy, 1990]).

Jurassic (Figure 4). In southern Illinois, oil expulsion began in the Middle Pennsylvanian and reached its peak in the Late Pennsylvanian–Early Permian. This period is coincident with extensive folding and faulting, which resulted in the development of many of the major traps in the system. Vertical focusing of oil along
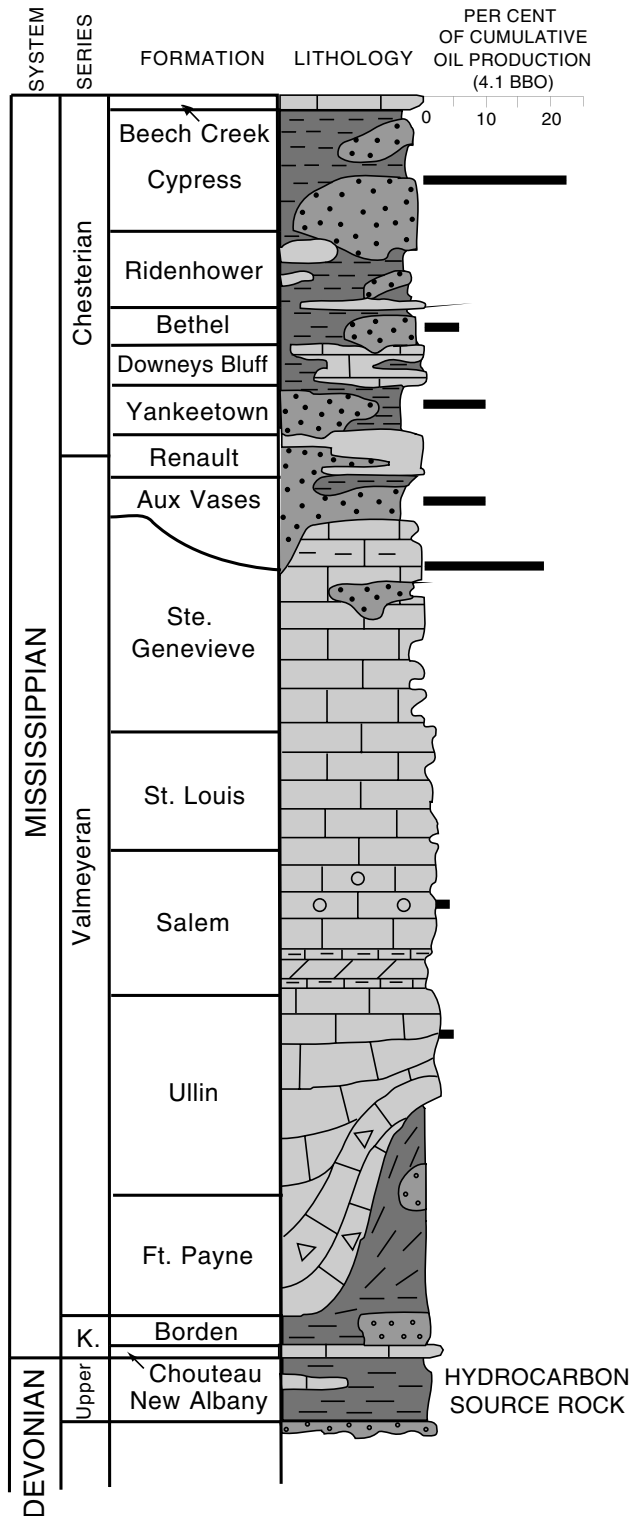
Figure 3. Generalized stratigraphic column of Mississippian and Devonian strata in the southern part of the Illinois basin. Horizontal black bars to the right of the lithologic column denote percent of cumulative production from adjacent reservoir units (modified from Bell et al., 1961 and Buschbach and Kolata, 1990).
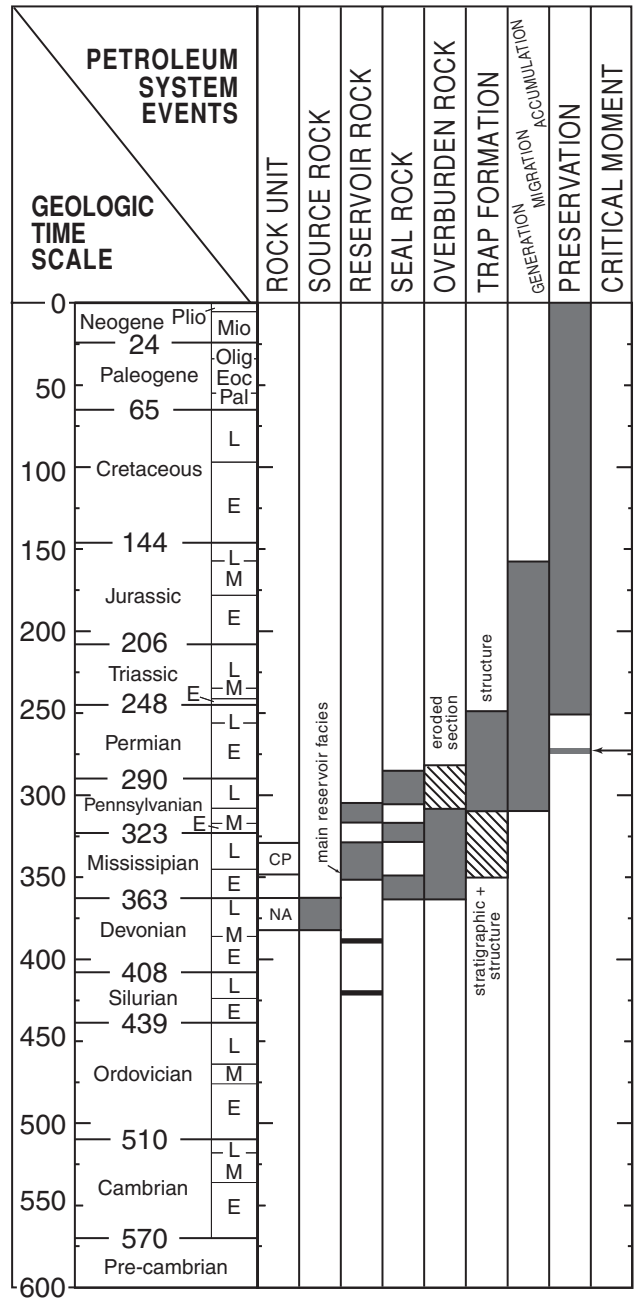
Figure 4. Events chart for the New Albany–Chesterian petroleum system of the Illinois basin.

faults into younger reservoir units served to expand the stratigraphic limits of the petroleum system. Erosion was associated with late Paleozoic uplift and was particularly widespread along the southern tectonic margin of the system. Thermal maturities of near-surface coal beds indicate that 1–3 km of overburden section was removed by erosion in southern Illinois (Cluff and Byrnes, 1990).

METHODOLOGY AND RESULTS

Determining petroleum charge and losses for this petroleum system requires the following: (1) a map delineating the extent of petroleum generation within the active pod of New Albany Shale; (2) a map dividing the system into major secondary-migration catchments based on buoyancy; (3) the quantity of original immature organic matter in the active pod of source rock; (4) the quantity of accountable petroleum discovered in the system; and (5) the quantity of residual oil lost during secondary migration. Complete analytical data, computational data, compiled data, and derivative maps on which the following petroleum charges and losses were determined are given in Higley et al. (2001).

Extent of Oil Generation

Vitrinite reflectance (R_o) is commonly used to determine thermal maturities of source rocks and thermal histories of petroleum systems (e.g., Houseknecht and Matthews, 1985; Cardott, 1989; Link and Bustin, 1989; Comer et al., 1994). Unfortunately, organic matter in source rocks does not always generate petroleum at the same thermal maturity levels (Hunt et al., 1991), which makes it difficult to universally assign specific R_o values to the extent of petroleum generation. Therefore, an index more directly related to the extent of oil generation is needed. Lewan (1985) showed experimentally that source rocks with type II kerogen have a common relationship between their atomic H/C ratio and percent of oil generated, irrespective of differences in the thermal maturity levels at which they generate petroleum. For example, an atomic H/C ratio of 0.76 for a high-sulfur kerogen and a low-sulfur kerogen in two different source rocks indicates that both source rocks have completed 50% of their petroleum generation, although the latter reached this stage at a higher thermal maturity level than the former (Lewan, 1985). Although the atomic H/C ratio is an excellent parameter to evaluate stages of petroleum formation, isolating kerogen from its host rock requires a lengthy laboratory procedure that involves strong-acid (HF and HCl) digestion of the rock matrix (Durand and Nicaise, 1980). This time-consuming analysis was alleviated by using the hydrogen index (HI) from Rock-Eval pyrolysis as a surrogate. The HI is the amount of hydrocarbons (HC) generated by Rock-Eval pyrolysis (S_2 = mg HC) relative to the total organic carbon (TOC) in the rock (mg HC/g

TOC) (Espitalié et al., 1977b; Peters, 1986). This parameter, which is measured on rock samples, has been shown to correlate with the atomic H/C ratio of kerogen isolated from the same samples (Bordenave et al., 1993).

As demonstrated by Espitalié et al. (1977a) and Baskin (1997), it is important to calibrate this relationship, because changes in HI values between 200 and 700 mg/g TOC may show no corresponding change in the atomic H/C ratio of kerogen. Therefore, it becomes necessary with type II kerogen to calibrate the relationship between HI and the atomic H/C ratio to determine the HI value at which atomic H/C ratios begin decreasing as a result of oil generation. A calibration of this type was conducted for the New Albany Shale on a subset of samples representing different thermal maturities based on Rock-Eval HI values (Figure 5). This calibration indicates that changes in HI values between 400 and 800 mg/g TOC cannot be equated to the extent of oil generation because there is no corresponding decrease in the essentially constant atomic H/C ratio of isolated kerogens. At HI values less than 400 mg/g TOC, however, there is a corresponding decrease in the atomic H/C ratio (or H/[C + H] mole fraction), which can be equated to the extent of oil generation.

The HI determinations by Rock-Eval analysis were conducted on 475 samples of New Albany Shale from outcrops, cores, and well cuttings collected at 262 localities in the Illinois basin. This sample base gave better coverage than preexisting vitrinite reflectance maps and a more direct and reliable index of oil generation. The HI values were contoured at 50 mg/g TOC intervals from 100 to 400 mg/g TOC. The HI values from samples having TOC values less than 2.5 wt. % were not used in the contouring. This limit was based on the petrographic observations that rocks having less than 2.5 wt. % TOC may not be capable of establishing a continuous bitumen network to facilitate primary migration and expulsion (Lewan, 1987). Less than 17% of the analyzed samples were eliminated on the basis of this criteria. The data were contoured and mapped using ArcInfo gridding utilities (Environmental System Research Institute, Inc., 1997), and the resulting map is shown in Figure 6. The pod of active source rock is outlined in this map by the 400 HI contour.

Secondary-Migration Catchments

Secondary-migration catchments are analogous to hydrological watersheds in that they represent the area in
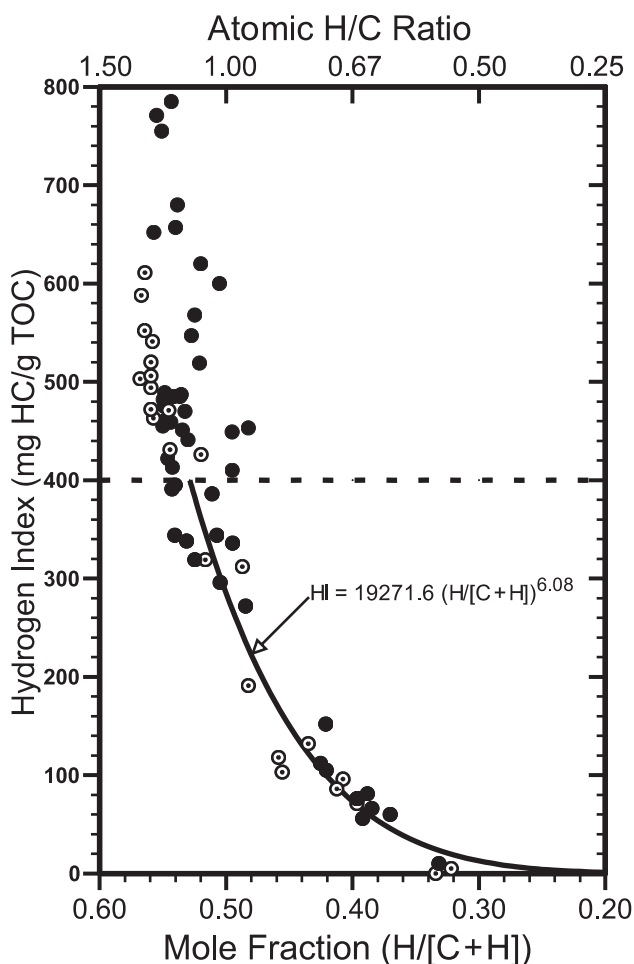
Figure 5. Plot of hydrogen index as determined by Rock-Eval pyrolysis on rocks vs. atomic H/C (or H/[C + H] mole fraction) of their isolated kerogen. Solid circles represent New Albany Shale samples used in this article, and open circles represent data reported by Espitalié et al. (1977a) for other source rocks containing type II kerogen.

which expelled petroleum is most likely to be confined as it migrates within and away from the pod of active source rock. Although hydrodynamic flow has been suggested as a driving force for secondary migration of petroleum in the Illinois basin (Bethke et al., 1991), subsequent work indicates that buoyancy is the dominant driving force (Abrams, 1995). This conclusion is in accordance with most secondary-migration concepts (Davis, 1987; England and Fleet, 1991) and is supported by the lack of compositional water-washing indicators in the oils (Palmer, 1984).

Applying a buoyancy drive to define secondary-migration catchments requires a structure map of regional carrier beds or seals. Most of the production in the Illinois basin is from discontinuous lenticular reservoirs that are separated from the New Albany Shale

by approximately 300 stratigraphic meters of limestone of Valmeyeran age (Figure 3). The importance of vertical migration along faults and fractures in this system is also apparent from the observation that 66% of petroleum production occurs in reservoirs above the active pod of source rock. Therefore, no continuous carrier unit can be employed to delineate specific migration pathway rays. Migration catchments, however, can be employed with the assumption that, irrespective of the tortuosity of vertical and lateral migration pathways, the petroleum charge from mature source rock in a defined catchment is maintained within the boundaries of that catchment. Assuming that thermal maturity is an approximate expression of burial depth, the HI map (Figure 6) was used as a paleostructure map to define migration catchments at maximum petroleum generation prior to uplift and erosion in the post–Early Permian. The absolute depths in this application are not critical, only relative depths, which can be inferred from the HI contours. As an example, the buoyancy model does not care whether the 300 HI contour represents a depth of 1000 m in the north or 2000 m in the south. Its only concern is that the 300 HI contour in the north and south represents the updip direction from the 250 HI contour.

An ArcInfo geographic information program for surface hydrologic analysis (Environmental System Research Institute, Inc., 1997) was used on this inferred paleostructure map to define catchments. This program is designed to delineate surface-water drainage basins around topographic highs, which is inversely analogous to movement of petroleum out of subsurface lows by buoyancy. To use this program, the HI contours were treated as depth values and multiplied by −1. Initially, the analysis yielded 21 drainage basins, which were condensed into seven catchments based on major unambiguous contour inflections and their inclusion of mature source rock. The seven catchments and their boundaries are shown in Figure 7. This analysis only delineates their boundaries within the 400 HI contour, and boundaries were extended over immature New Albany Shale by drawing perpendicular lines outward from where the boundaries intersect the 400 HI contour. Each of these catchments can be treated as a subsystem that has its own petroleum charge and losses.

Original Organic Matter

Determining the original amount of organic matter within the pod of active source rock is critical to
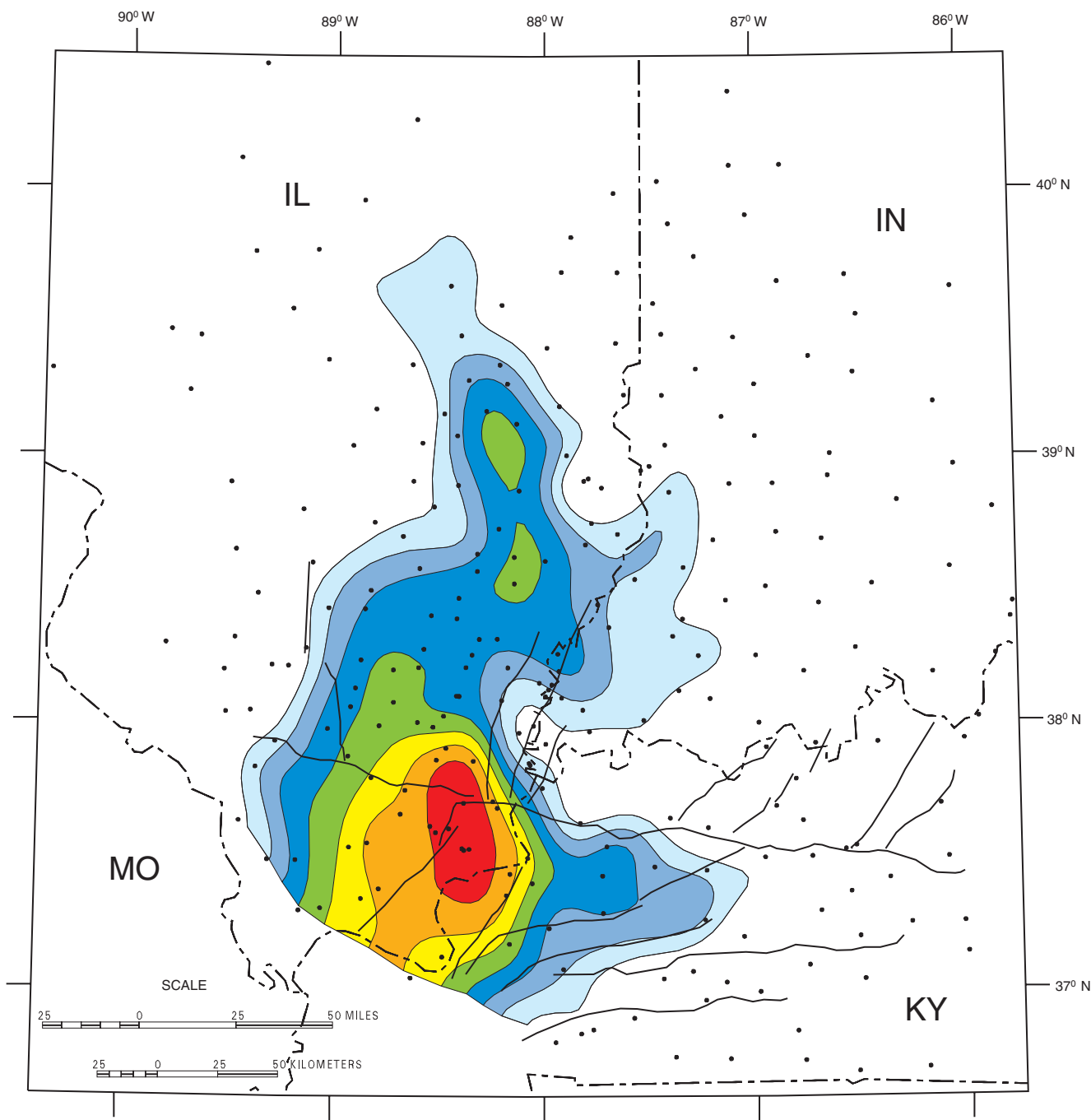
Figure 6. Contoured HI map of mature (> 400 mg HC/g TOC) New Albany Shale source rock (TOC > 2.5 wt. %). Sample sites used to construct contours are shown as solid circles. Fault traces are from Nelson (1990). Contour intervals are in mg HC/g TOC, and colored areas represent HI intervals of 400–350 (light blue), 350–300 (medium blue), 300–250 (dark blue), 250–200 (green), 200–150 (yellow), 150–100 (orange), and <100 (red).

establishing the petroleum charge. This determination requires knowing the volume of mature source rock and its original TOC prior to maturation. Volumes of mature New Albany Shale can be calculated by superimposing the HI map (Figure 6) on published isopach maps of the New Albany Shale (Cluff et al., 1981;

Frankie et al., 1994). Unfortunately, such a computation would include volumes of non–source rock that occur within some members of the New Albany Shale (Hannibal, Saverton, Ellsworth, and Selmier), which would unjustly enhance the petroleum charge. Therefore, an isopach map of only the source rock within the
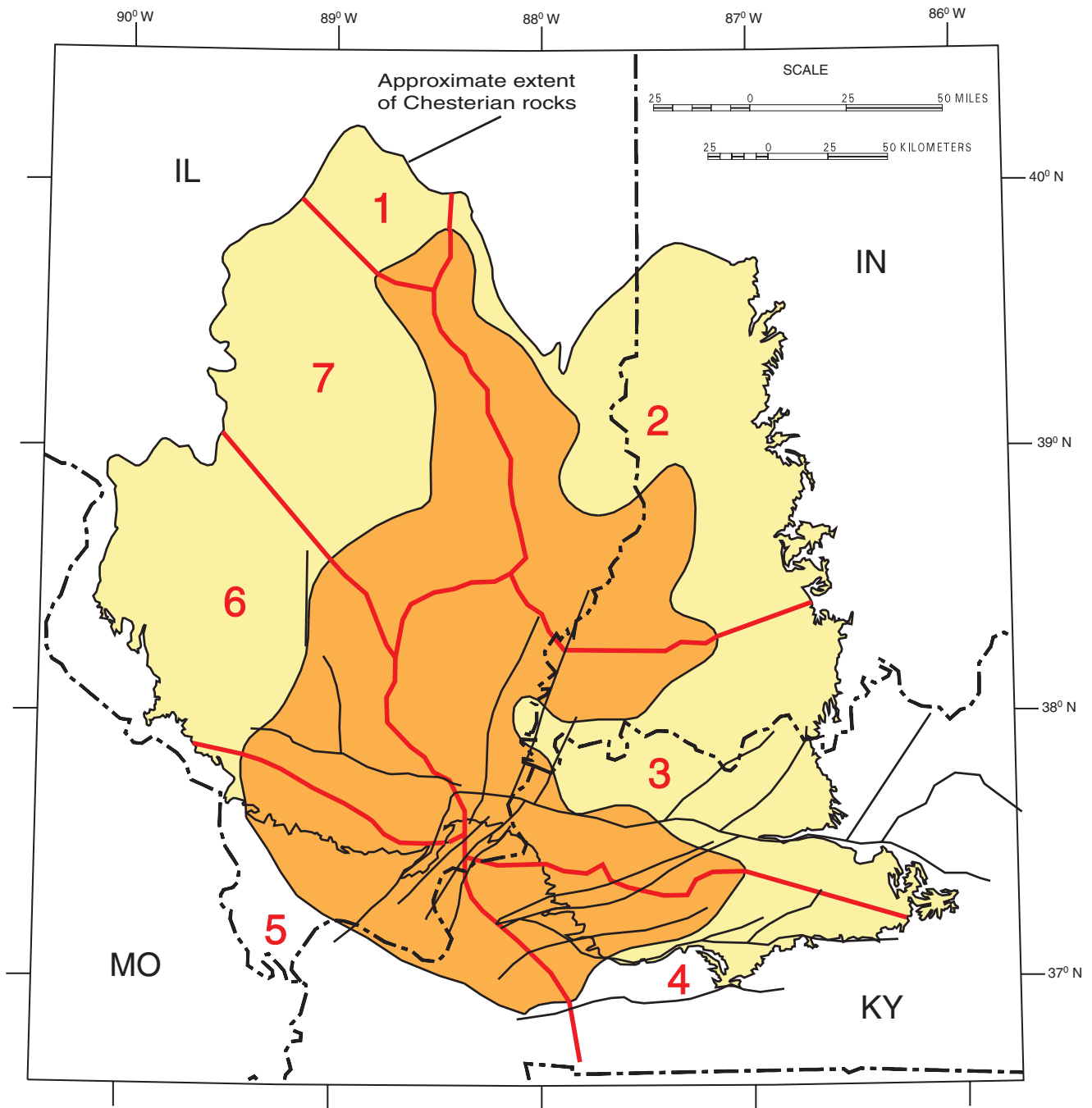
Figure 7. Map showing seven secondary-migration catchments defined by buoyancy drive using the HI map (Figure 6) as a paleostructure surface prior to uplift and erosion. Orange area represents mature source rock and yellow area represents immature source rock to the Chesterian outcrop/subcrop.

New Albany Shale was compiled using isopach maps by Lineback (1981) of the main source rock members, including the Blocher Member, Selmier Member, and composited upper-shale members (i.e., Clegg Creek, Camp Run, Morgan Trail, Grassy Creek, and Sweetland Creek).

These isopach maps were corrected to reflect source rock thickness using detailed TOC determinations on cores and calibrated analyses of well logs. The TOC determinations on nine cores at various maturity levels indicate that 92–100% of the composited upper-shale members consists of source rock (TOC ≥

2.5 wt. % [Lewan et al., 1995, table 3]). Thicknesses in the isopach map of the composited upper-shale members were corrected by the mean value of 97.5% (Lewan et al., 1995, table 3) for a more accurate determination of the source rock volume. The TOC determinations on eight cores at various maturity levels indicate that 98–100% of the Blocher Member consists of source rock (TOC ≥ 2.5 wt. % [Lewan et al., 1995, table 3]). Thicknesses in the isopach map of the Blocher Member were corrected by the mean value of 99.2% (Lewan et al., 1995, table 3) for a more accurate determination of the source rock volume. Unlike the relatively uniform distribution of source rock percentages in the composited upper-shale and Blocher members, percent of source rock in the Selmier Member showed greater variability in thickness of non–source rock intervals (Lewan et al., 1995, table 3). Therefore, gamma-ray logs of 87 wells in cross sections constructed by Cluff and Reinbold (1981) were used to determine the percent of non–source rock intervals in the Selmier Member. Non–source rock intervals were defined as intervals having API units less than 120. These percentages were mapped and gridded, and resulting values were used to correct the isopach map of the Selmier Member to source rock thicknesses. The corrected isopach maps showing thickness of source rock in each member were summed (Figure 8) and used to calculate volumes of mature source rock (i.e., HI < 400 mg/g TOC) for each catchment (Table 1).

The next step involves determining the original TOC of these mature source rock volumes prior to maturation. An implicit assumption in this determination is that immature organic matter originally deposited in the mature source rocks was uniform in type and similar to that occurring in immature source rocks outside the 400 HI contour. Several lithofacies have been identified in the New Albany Shale (Cluff, 1980), but those representing source rocks (TOC > 2.5 wt. %) consistently contain organic matter composed of more than 90 vol. % oil-prone, amorphous, type II kerogen (Barrows and Cluff, 1984). Visual differences observed in the kerogen morphologies (Barrows and Cluff, 1984) can be attributed to the effects of thermal maturation (Buchardt and Lewan, 1990). The uniformity of the original organic matter deposited in the source rocks of the New Albany Shale is also reflected in the narrow ranges of stable carbon isotope signatures of their kerogen ($\delta^{13}C = -28$ to -30 per mil vs. Peedee belemnite [PDB] [Lewan, 1980]) and their consistent carbon/sulfur ratios (C/S = 2.8
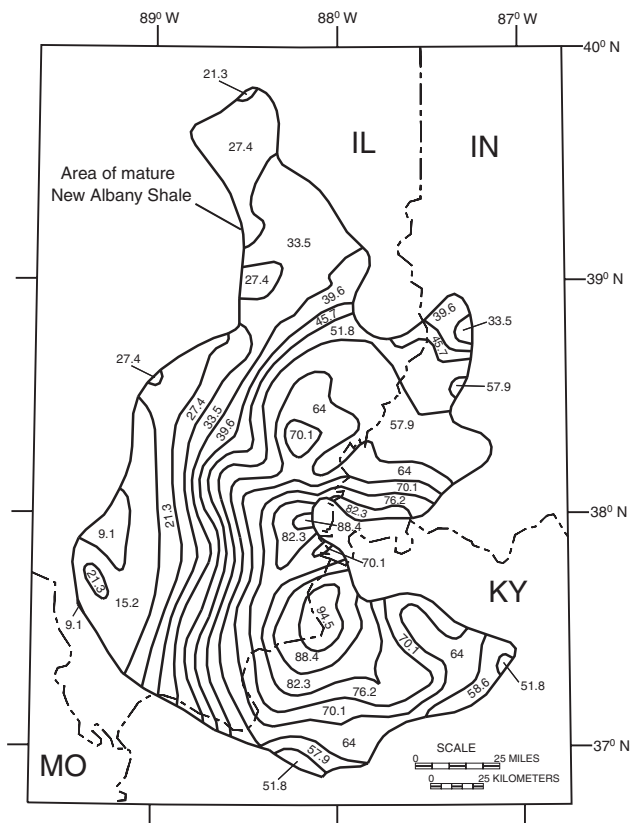
Figure 8. Isopach map of total mature source rock thicknesses in the New Albany Shale. Mean thicknesses given in meters for each polygon.

[Frost, 1996]) at various levels of thermal maturation and at different stratigraphic and geographic locations.

Although the type of original organic matter deposited in the source rocks can be assumed to be uniform over the basin, the thickness of source rock ranges from 10 m in immature outcrops to more than 90 m in the mature depocenter (Figure 8). Lewan et al. (1995) proposed two end-member models to determine the original TOC of the thickening mature source rock: steady-state and dilution. The steady-state model assumes that the average original TOC of the thicker source rock section prior to maturation was the same as the thinner immature source rock section. As a result of this assumption, the amount of organic matter deposited and preserved in a source rock section maintains a constant proportionality with the amount of inorganic sediment deposited. Using a weighted-mean TOC value of 8.8 wt. %, Lewan et al. (1995, table 5) calculated that 412 billion t (metric tons) of immature TOC originally occurred within the pod of active source rock. Conversely, the dilution model assumes that the amount of original TOC deposited and pre-

**Table 1.** Volume (km³) of Mature New Albany Shale Source Rock for Each HI Interval by Catchment

Catchment Number	HI Interval (mg HC/g TOC)							Total
	400–350	350–300	300–250	250–200	200–150	150–100	<100	
1	10.2	0.0	0.0	0.0	0.0	0.0	0.0	10.2
2	160.9	76.1	67.7	18.3	1.0	0.0	0.0	324.0
3	165.5	118.5	178.6	63.4	37.7	38.3	42.5	644.5
4	49.9	80.5	47.8	17.6	15.2	16.5	9.5	237.0
5	17.9	18.2	20.6	29.8	58.0	84.2	20.2	248.9
6	9.3	11.7	21.1	25.2	15.4	29.6	26.9	139.2
7	46.3	36.3	63.9	16.8	0.0	0.0	0.0	163.3
Total	460.0	341.3	399.7	171.1	127.3	168.6	99.1	**1767.1**

served remains fixed over the entire basin and the thickening of the source rock section is solely the result of increased inorganic sediment input. As a result of this dilution, the average original TOC of a source rock section decreases with increasing thickness. Using this model, Lewan et al. (1995, table 5) calculated that 285 billion t of original immature TOC occurred within the pod of active source rock.

Although the actual original TOC is thought to be somewhere between these two end-member models, the observation that organic richness increases as source rock thickness decreases (Nixon, 1973; Schmoker, 1980; Robl et al., 1983; Comer, 1991, 1992) suggests that values closer to the dilution model are more likely. The TOC and thicknesses reported by Robl et al. (1983) on immature source rocks in the neighboring Devonian–Mississippian black shales provide important constraints on determining the original TOC of the thicker mature source rocks. Robl et al. (1983) reported weighted-mean TOC values for thicknesses of the major source rock members in the Ohio Shale (i.e., Huron and Cleveland members) in central Kentucky, adjacent to the Illinois basin. The Ohio Shale is lithologically similar and age equivalent to the New Albany Shale. Around the Findly arch, the source rock bearing members are immature and range in thickness from 10 to 95 m (Robl et al., 1983). A logarithmic plot of the weighted-mean TOC values vs. thickness yields a good linear relationship, as shown in Figure 9. This relationship extends over the same range of source rock thickness observed in the New Albany Shale and is used to calculate the original TOC of the mature source rocks within the 400 HI contour for each 50 HI contour interval (Figure 10; Table 2). The resulting 301 billion t of original TOC for the mature source rock (Table 2) is intermediate to the 285 and

411 billion t determined by the dilution and steady-state models, respectively (Lewan et al., 1995). The differences between these two end-member values and the 301 billion t determined from the relationship in Figure 9, however, suggest the dilution model gives a more realistic value than the steady-state model.

$$Log (TOC) = -0.287(Log[T]) + 1.483$$
$$corr. coef. = 0.951$$
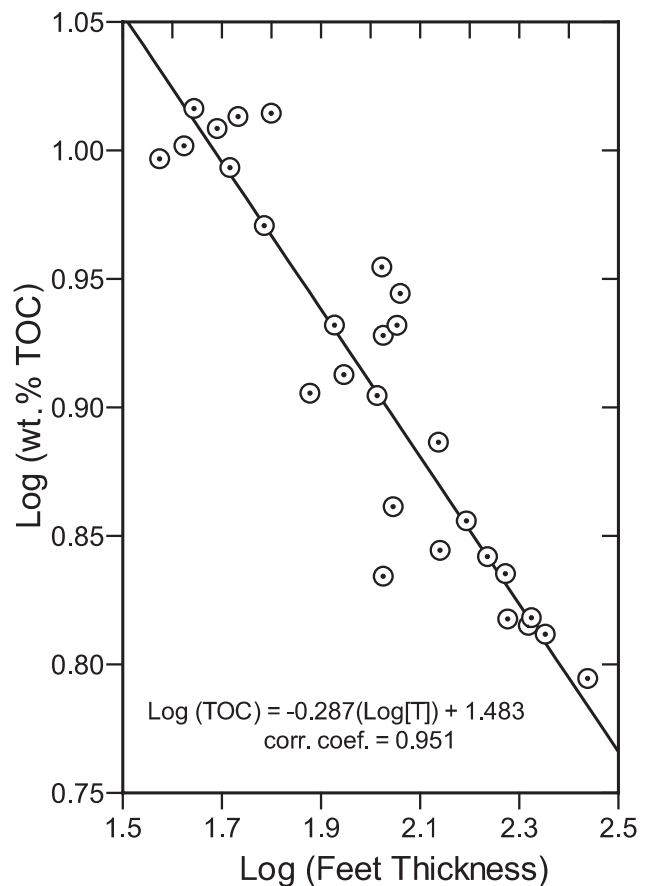
Figure 9. Log plot of source rock thickness vs. weighted average TOC (wt. %) for immature Mississippian–Devonian black shales in central Kentucky as reported by Robl et al. (1983).
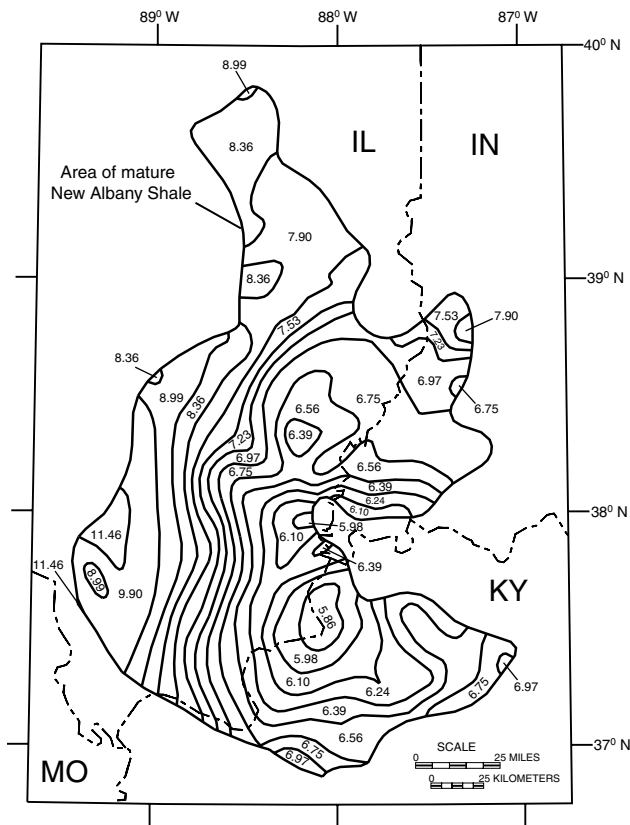
Figure 10. Map showing original organic carbon values for mature New Albany Shale as calculated by the relationship in Figure 9 and the summed thicknesses given in Figure 8. Mean original organic carbon values given as wt. % of rock for each polygon.

Accountable Petroleum

Mast and Howard (1990) estimated that the Illinois basin contains 12 billion bbl of original oil in place (OOIP) on the basis of a 36% recovery factor. Geo-

chemical correlations by Hatch et al. (1990) indicate that more than 99% of this produced oil was generated by source rocks in the New Albany Shale. The remaining produced oil (<1%) was generated from Ordovician source rocks that reside in Ordovician reservoir rocks (Hatch et al., 1990; Guthrie and Pratt, 1994). Therefore, values of OOIP used in this article considered only production from reservoirs of Silurian–Pennsylvanian age. Cumulative or estimated ultimate production for reservoirs within this age interval in 721 fields is 4.14 billion bbl (Higley et al., 2001). Using a calculated mean recovery factor of 36.22%, the OOIP for this petroleum system is 11.43 billion bbl. Forty-five percent of these fields occur within the 400 HI contour and account for two thirds of the OOIP (Higley et al., 2001). As shown in the map of oil and gas wells (Figure 11), most of the produced oil occurs north of the Cottage Grove and Rough Creek–Shawneetown faults (98% of the OOIP). Table 3 gives the OOIP and percent of total OOIP for each catchment within and outside the 400 HI contour.

In addition to economic accumulations, accountable discovered petroleum includes noneconomic tar and heavy oil deposits. Petroleum that leaks to or near the surface is subjected to a variety of processes, including microbial degradation (Winters and Williams, 1969), water washing (Palmer, 1984), and devolatilization (Brunnock et al., 1968). These processes result in inspissation of the original petroleum that eventually leads to the formation of heavy oil or tar. Under the most severe degradation, these processes collectively result in an 80–90% loss of the original oil (Tannenbaum et al., 1987), but a residual tar representing 10–20% of the original oil remains as an indicator of petroleum leakage. Therefore, tar deposits are an excellent indicator of leaky systems, and unless major ero-

Table 2. Mass (10^{12} g) of Original Organic Carbon in Mature New Albany Shale Source Rock for Each HI Interval by Catchment

Catchment Number	HI Interval (mg HC/g TOC)							
	400–350	350–300	300–250	250–200	200–150	150–100	<100	Total
1	1,922	0	0	0	0	0	0	1,922
2	26,336	12,156	10,775	2,961	0	0	0	52,228
3	24,011	17,294	26,546	9,307	5,324	5,360	5,994	93,836
4	7,535	11,721	6,777	2,454	2,105	2,283	1,317	34,192
5	3,013	3,112	3,585	5,065	9,332	12,935	2,880	39,922
6	2,054	2,529	4,271	4,694	27,564	4,705	3,922	49,739
7	8,656	6,517	10,786	2,720	0	0	0	28,679
Total	73,527	53,329	62,740	27,201	44,325	25,283	14,113	**300,518**
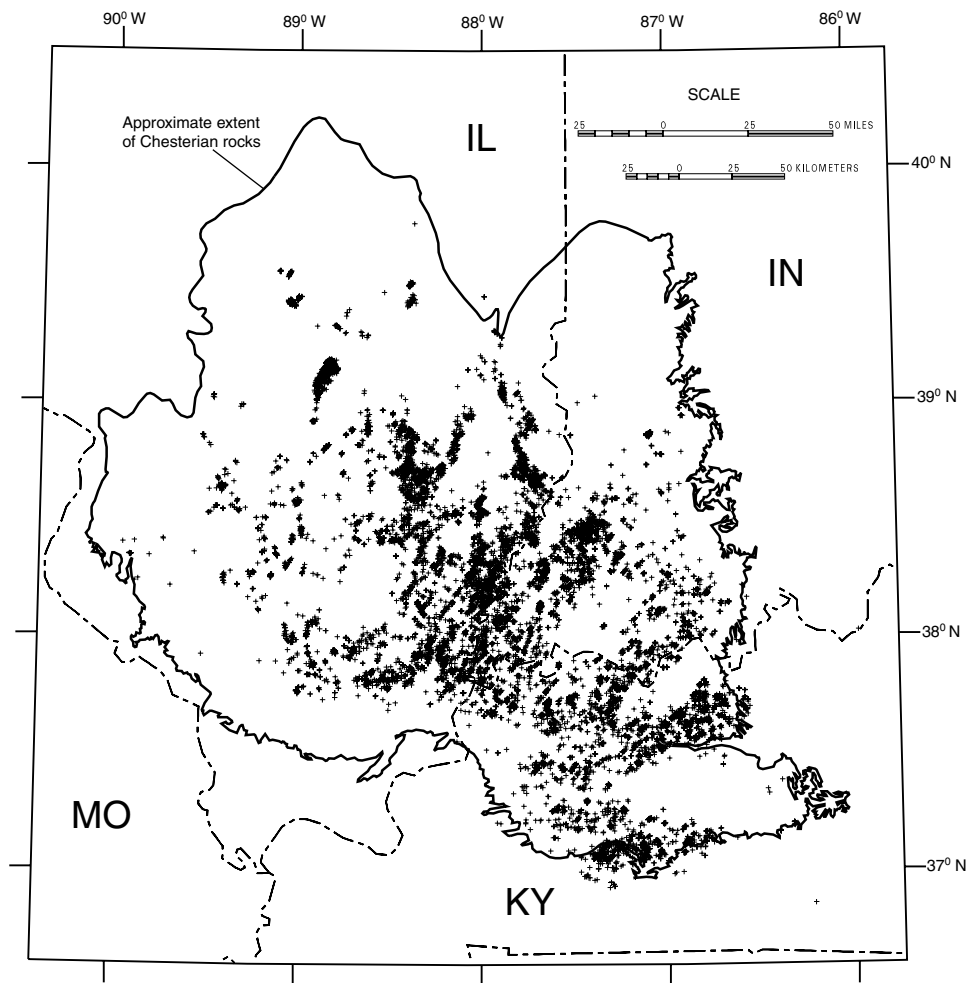
Figure 11. Map showing wells producing from Chesterian reservoirs (Petroleum Information Corporation, 1996).

sional events have totally removed tar-bearing sections, it is difficult to advocate large petroleum losses without the recognition of tar occurrences. A few prominent examples of this type of petroleum loss include 12–16 billion bbl of tar in the Tar Sand Triangle of Utah (Crysdale and Schenk, 1988), 626 billion bbl of heavy bitumen in the Athabasca tar deposits of Canada (Carrigy, 1974), and 1200 billion bbl of heavy oil and tar in the Orinoco Heavy Oil belt of Venezuela (Roadifer, 1987). Within the New Albany–Chesterian petroleum system of this article, tar occurrences are restricted to catchments 3 and 4.

Table 3. Original Oil In Place (10^9 bbl) inside and outside the 400 HI Contour for Each Catchment

Catchment Number	Within 400 HI		Outside 400 HI		Total	
	10^9 bbl	%	10^9 bbl	%	10^9 bbl	%
1	0.000	0.0	0.012	100.0	0.012	0.1
2	2.336	67.8	1.110	32.2	3.446	30.2
3	2.041	71.1	0.829	28.9	2.870	25.1
4	0.033	29.2	0.080	70.8	0.113	1.0
5	0.000	0.0	0.000	0.0	0.000	0.0
6	1.528	76.0	0.483	24.0	2.011	17.6
7	1.581	53.2	1.393	46.8	2.974	26.0
Total	7.519	65.8	3.907	34.2	**11.426**	**100.0**

Tar deposits in catchment 3 occur in sandstones of Chesterian age in Crawford County, Indiana (J. Rupp, 1997, personal communication) and of Chesterian–Pennsylvanian age in Breckinridge, Hardin, McLean, and Grayson counties of Kentucky (Ball Associates, 1965). These tar deposits are not large enough to be assessed, but they do indicate that petroleum leakage has occurred in this catchment. The vanadium-nickel fraction (i.e., V/[V + Ni]) of oils and tars has been shown to be a good geochemical correlation parameter that is not affected by biodegradation (Brunnock et al., 1968), water washing (Davis and Gibbs, 1975), secondary migration (Al-Shahristani and Al-Atyia, 1972), or thermal stress (Costantinides et al., 1959). Table 4 shows that the vanadium-nickel fraction of the tars from Indiana correlate with New Albany Shale oils, which have a dominance of nickel over vanadium (i.e., V/[Ni + V] < 0.5). Conversely, the tar from the Caseyville sandstone in Kentucky (i.e., catchment 3) has a distinctly different vanadium-nickel fraction (i.e.,

V/[Ni + V] > 0.5), which indicates it was derived from a different source rock of another petroleum system.

Catchment 4 has large tar deposits in Chesterian and Pennsylvanian sandstones (McGrain, 1976; Noger, 1987) that have been estimated at 3.41 billion bbl in place (Crysdale and Schenk, 1988). Assuming this tar was derived from the New Albany Shale, Lewan et al. (1995) estimated on the basis of sulfur content that these deposits represent 30.4 billion bbl of undegraded original in place oil; however, subsequent work (T. Hamilton-Smith, 1994, personal communication) has shown that these tars are not part of the New Albany–Chesterian petroleum system. Table 4 shows that the vanadium-nickel fraction of these tars is distinctly different from that of oils derived from the New Albany Shale. The similar predominance of vanadium over nickel in these tars with that of the Caseyville sandstone tar in catchment 3 of Kentucky (Grayson County, Table 4) suggests these tars are genetically re-

Table 4. Proportionality (V/[Ni + V]) of Vanadium (V) to Nickel (Ni) in Tars and Crude Oils from Catchments 3 and 4

Petroleum Type	Reservoir Unit	County, State	Mean	Standard Deviation*	Number of Samples	References**
Catchment 3						
Tar	Caseyville Sandstone	Grayson, Kentucky	0.73	na	1	1
	Tar Springs Sandstone	Crawford, Indiana	0.34	na	1	1
	Tar Springs Sandstone	Crawford, Indiana	0.33	na	1	1
Oil	Salem Limestone	Greene, Indiana	0.29	na	1	1
	New Albany Shale	Harrison, Indiana	0.33	na	1	1
	Waltersburg Sandstone	Gibson, Indiana	0.23	0.03	2	2
	Waltersburg Sandstone	Posey, Indiana	0.27	0.03	7	2
	Waltersburg Sandstone	White, Illinois	0.26	0.03	8	2
	Waltersburg Sandstone	Gallatin, Illinois	0.27	0.03	5	2
	Waltersburg Sandstone	Saline, Illinois	0.26	0.06	3	2
Catchment 4						
Tar	Caseyville Sandstone	Edmonson, Kentucky	0.71	na	1	1
	Caseyville Sandstone	Edmonson, Kentucky	0.74	na	1	3
	Big Cliffy Sandstone	Logan, Kentucky	0.72	na	1	1
	Big Cliffy Sandstone	Logan, Kentucky	0.68	na	1	3
Oil	Tar Springs Sandstone	Butler, Kentucky	0.29	na	1	1
	Hardinsburg Sandstone	Butler, Kentucky	0.32	0.02	2	1
	Warsaw Limestone	Warren, Kentucky	0.25	na	1	4

*na = not applicable.
**1 = this study; 2 = Mast et al. (1968); 3 = Hosterman et al. (1990); 4 = Lewan (1980).

lated to the same source rock but not related to the New Albany Shale. The predominance of vanadium over nickel and relatively high sulfur contents of these tars (i.e., 1.6–2.2 wt. % [Hosterman et al., 1990]) are indicative of a carbonate source rock (Lewan, 1984). Prospective carbonate sources for these tars include the Mississippian St. Louis Limestone (Ridgley and Nuccio, 1995), Upper Ordovician Maquoketa Shale (Guthrie and Pratt, 1994), and Middle Ordovician Dutchtown Limestone (William and Buschbach, 1975). Although these tar deposits indicate significant leakage of petroleum from catchment 4, their quantities cannot be included as part of the petroleum leakage losses for the New Albany–Chesterian petroleum system as previously reported by Lewan et al. (1995).

Residual Migration Losses

Secondary migration of expelled oil through fractures and faults appears to be critical in supplying oil to isolated lenticular sandstone reservoirs in the Illinois basin. These conduits are an effective means of migrating oil with no significant residual losses along migration pathways; however, porous carrier beds are likely to have been a factor in lateral migration of petroleum away from fracture and fault conduits during secondary migration prior to and during late Paleozoic tectonism (i.e., Alleghanian and Ouachita orogenies). Migration through porous carrier beds is considered to be less effective because granular rocks are thought to retain some residual oil in their pores as oil migrates through them (Schowalter, 1979). This residual oil retained in carrier beds has been credited with the loss of enormous quantities of unaccountable petroleum in some material-balance studies (e.g., MacGregor and Mackenzie, 1987; Mackenzie and Quigley, 1988; Forbes et al., 1991; Mohamed et al., 1999).

Calculated residual migration losses in this article are based on seven carrier beds. Four of the carrier beds represent the major producing reservoir rock units of Mississippian age and include the Ste. Genevieve, Aux Vases, Bethel, and Cypress formations. The other three carrier beds are not as well defined and represent composites of Pennsylvanian, Devonian, and Silurian reservoirs. The lateral extent of secondary migration was determined from map outlines encompassing production and shows for each carrier bed (Figures 12, 13). The show data are from the Petroleum Information database (Petroleum Information Corporation, 1996) and include oil and gas shows. The area within these outlines was determined for each catchment and is

considered to represent the maximum extent of secondary migration through the porous carrier beds.

Although petroleum reservoirs may represent the entire thickness of a porous rock unit, only a small part of a carrier bed experiences migrating petroleum as it feeds a reservoir. Schowalter (1979) suggests that only the upper few feet of a carrier bed experience secondary petroleum migration, and England et al. (1987) suggest that only 1–10% of the cross sectional thickness of a carrier bed experiences secondary petroleum migration. A weighted-mean reservoir thickness of 5.1 m for the Illinois basin was calculated from the thicknesses and areas of 1240 pay zones in 565 fields compiled by Mast (1970). Using the upper cross sectional limit of 10%, a 0.5 m thickness is used as the average amount of carrier-bed thickness that experiences secondary migration for each carrier bed. This thickness times the area of each carrier bed in each catchment gives the rock volume that experienced secondary migration. Porosities for these volumes of carrier bed in the Ste. Genevieve, Aux Vases, Bethel, and Cypress formations are taken from porosity contour maps (Figure 12), which were constructed from available core data. Pore volumes for each of these carrier beds are calculated by superimposing the porosity contour maps over the secondary-migration outline maps (Figure 12). The surface area of each resulting polygon is multiplied by the 0.5 m thickness and its mean porosity to give the pore volume that has experienced secondary migration. Porosities for the composite Pennsylvanian, Devonian, and Silurian carrier beds are taken from the mean porosities given by Howard (1990; 18, 14, and 13%, respectively) and used uniformly over the entire area of outlined secondary migration (Figure 13) and multiplied by a 0.5 m thickness. The calculated pore volume of each carrier bed that has experienced migrating petroleum in each catchment is given in Table 5.

The final step in calculating residual migration losses is to assign a residual oil saturation to the calculated pore volume of each carrier bed. Estimates of the amount of residual petroleum retained in a carrier bed range considerably, from <1 to 30% of the pore volume (Schowalter, 1979; Catalan et al., 1992; Hirsch and Thompson, 1995). For this article, a residual oil saturation of 7.4%, as determined experimentally by Catalan et al. (1992) for a tilted column, was used to determine the residual losses resulting from secondary migration. Applying this percentage to the pore volume that experienced secondary migration in each carrier bed (Table 5) gives the residual petroleum
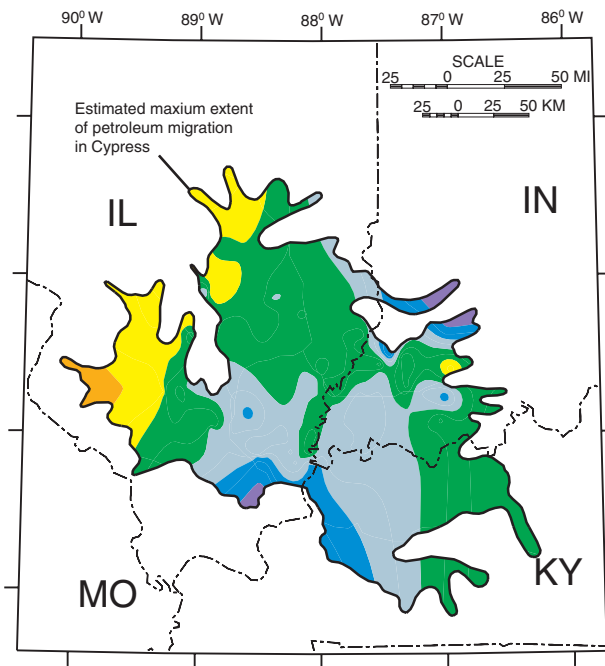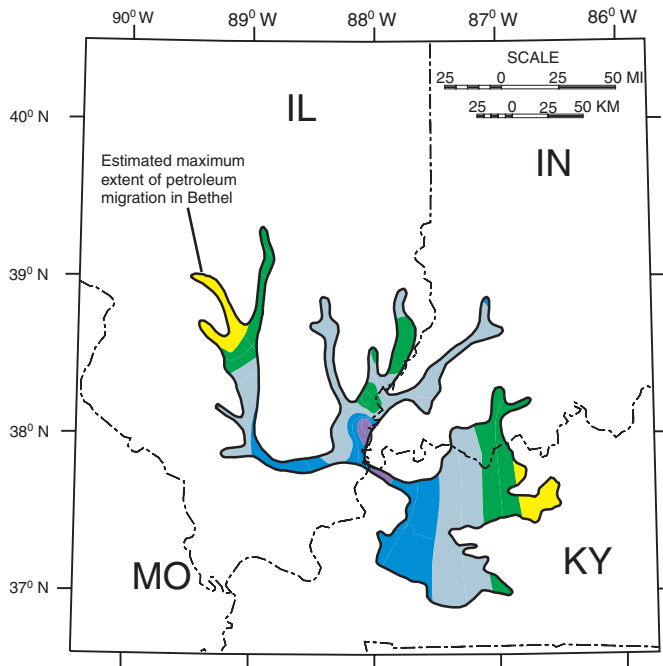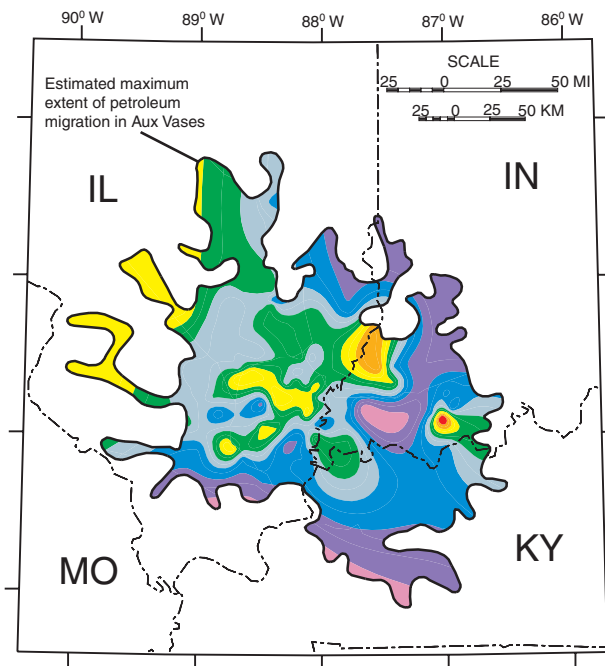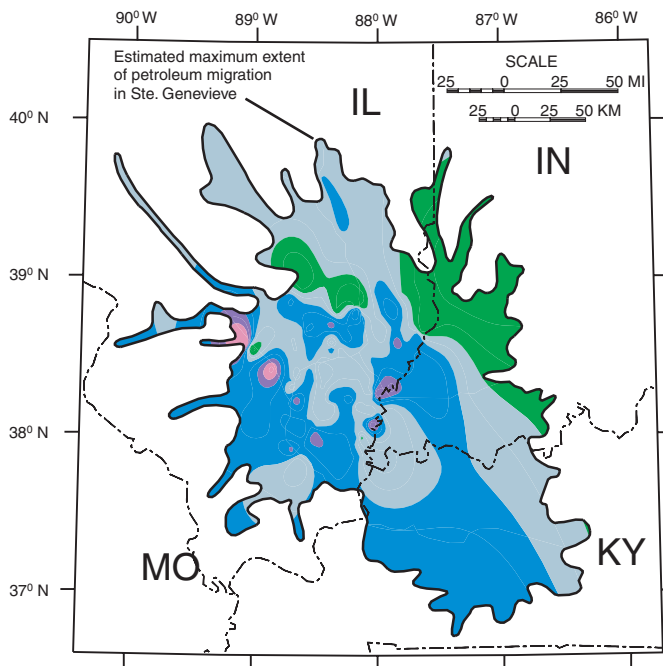
Figure 12. Maps showing the outline of maximum extent of secondary oil migration based on hydrocarbon shows and production for the (A) Cypress, (B) Bethel, (C) Aux Vases, and (D) Ste. Genevieve formations. Colored areas denote porosity intervals of 0–4% (pink), 4–8% (purple), 8–12% (dark blue), 12–16% (light blue), 16–20% (green), 29–24% (yellow), 24–28% (orange), and >28 (red).
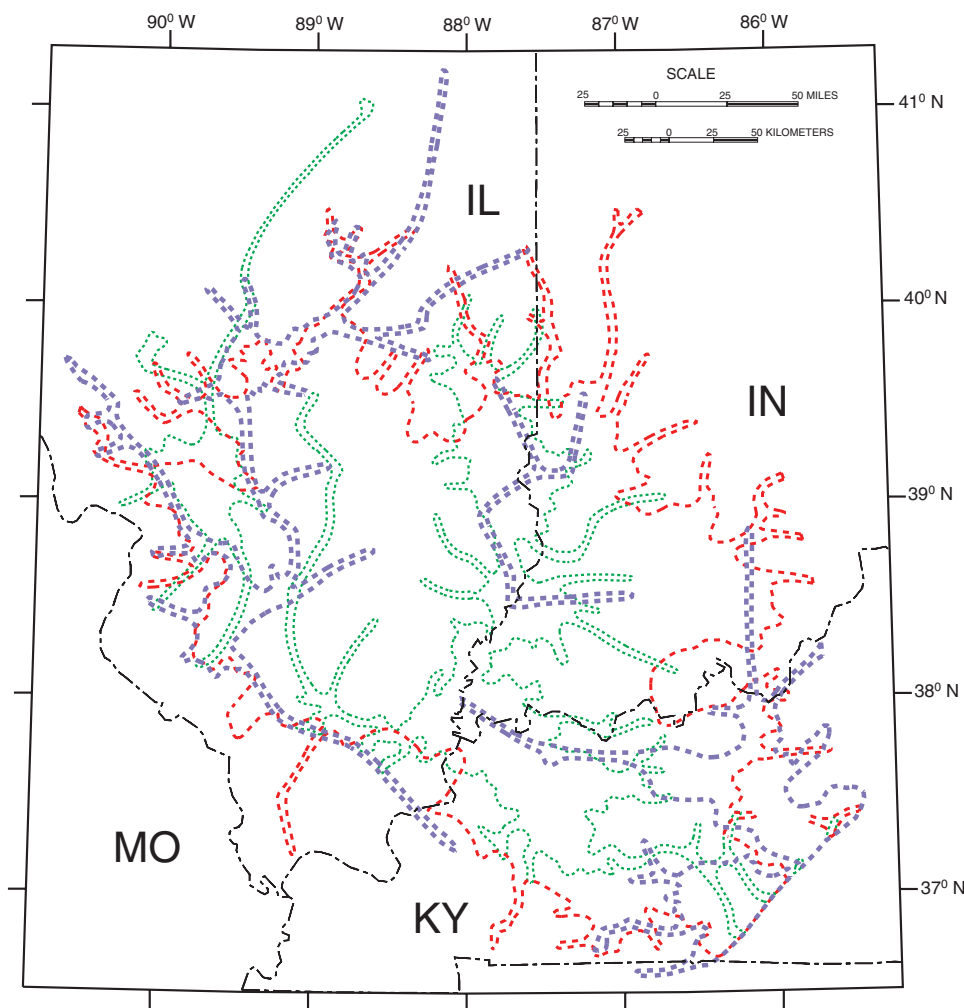
Figure 13. Map showing the maximum extent of secondary oil migration based on hydrocarbon shows and production in composite carrier units of Pennsylvanian (green dashed outline), Devonian (red dashed outline), and Silurian (purple dashed outline) age.

migration losses for each catchment. Table 6 shows that the total residual petroleum loss for the entire basin is 9 billion bbl. Catchment 3 shows the greatest residual loss, at 3 billion bbl, and catchment 5 has the smallest residual loss, at 39 million bbl. Numerical simulations and experiments by Hirsch and Thompson (1995) indicate that oil saturation for porous rocks that experience secondary oil migration are on the order of 1% or less, rather than the 7.4% used in this article. Therefore, the residual losses in Table 6 are likely to be maximum values and may be exaggerated by a factor of more than seven.

Petroleum Charge

Petroleum charge, the amount of oil expelled from a maturing source rock, is one of the most important and elusive quantities needed in conducting a material-balance assessment (Lewan et al., 1995). Two commonly used laboratory pyrolysis methods for determin-

ing petroleum charge are Rock-Eval pyrolysis (Cooles et al., 1986) and hydrous pyrolysis (Lewan, 1994). Both pyrolysis methods give significantly different expelled oil quantities as a result of differences in their pyrolysis conditions and product collection procedures. This article uses both methods in determining petroleum charge and compares the results with an actual petroleum charge derived from one of the well-constrained catchments that has no significant petroleum leakage or erosional losses.

Rock-Eval

Rock-Eval is an open-system pyrolysis method that involves heating 10–20 mg of a powdered rock at atmospheric conditions from 300 to 600°C over a period of time ranging from 15 to 30 min. Vaporized products evolved from the sample during this heating (i.e., volatile S_1 and generated S_2 hydrocarbon products) are swept from the oven by a carrier gas into a flame ionization detector, which is calibrated to give

Table 5. Pore Volume (km^3), Range of Porosities, and Number of Polygons of 0.5 m–Thick Carrier Bed That Experienced Migrated Oil

	Major Carrier Beds						
	Pennsylvanian	Cypress	Bethal	Aux Vases	Ste. Genevieve	Devonian	Silurian
Catchment 1							
Pore Volume (km^3)	31.4	4.6	0.0	8.7	9.6	87.8	61.9
Porosity (%)	18	23	0	15–19	13	14	13
Number of Polygons	1	1	0	3	1	1	1
Catchment 2							
Pore Volume (km^3)	701.2	655.2	127.8	537.5	962.5	1,410.3	106.9
Porosity (%)	18	8–22	12–17	6–26	5–20	14	13
Number of Polygons	1	32	6	33	20	1	1
Catchment 3							
Pore Volume (km^3)	683.8	1,319.4	553.2	1,003.0	1,088.3	1,521.8	382.1
Porosity (%)	18	9–20	5–24	3–29	5–19	14	13
Number of Polygons	1	26	23	50	34	1	1
Catchment 4							
Pore Volume (km^3)	169.8	215.9	181.0	70.0	325.5	586.9	189.4
Porosity (%)	18	9–20	9–17	4–9	10–15	14	13
Number of Polygons	1	10	7	7	9	1	1
Catchment 5							
Pore Volume (km^3)	0.0	12.6	0.0	11.4	40.4	16.9	1.7
Porosity (%)	0	17–19	0	4–17	11–13	14	13
Number of Polygons	0	2	0	9	5	1	1
Catchment 6							
Pore Volume (km^3)	284.3	800.9	146.6	433.5	288.8	688.1	223.9
Porosity (%)	18	7–25	11–21	4–22	3–17	14	13
Number of Polygons	1	15	10	31	31	1	1
Catchment 7							
Pore Volume (km^3)	175.7	641.7	110.0	680.3	621.9	958.3	163.9
Porosity (%)	18	13–23	13–21	11–22	3–18	14	13
Number of Polygons	1	18	8	23	38	1	1

Table 6. Residual Losses of Petroleum (10^6 bbl) in Carrier Beds as a Result of Secondary Migration*

	Major Carrier/Reservoir Beds							
Catchment No.	Pennsylvanian	Cypress	Bethal	Aux Vases	Ste. Genevieve	Devonian	Silurian	Total
1	14.6	2.2	0.0	4.0	4.5	40.9	28.8	95.0
2	326.4	304.9	59.5	250.2	448.0	656.4	52.7	2098.1
3	318.3	614.1	257.5	466.9	506.6	708.3	177.9	3049.6
4	79.0	100.5	84.3	32.6	151.5	273.2	88.1	809.2
5	0.0	5.9	0.0	5.3	18.8	7.8	0.8	38.6
6	132.3	372.8	68.2	201.7	134.4	311.0	104.2	1324.6
7	81.8	298.8	51.2	316.6	289.5	446.0	76.3	1560.2
Total	952.4	1699.2	520.7	1277.3	1553.3	2443.6	528.8	**8975.3**

*Values are based on 7.4% oil saturation and a 0.5 m cross sectional thickness of the carrier bed that experienced secondary oil migration.

quantitative yields (Espitalié et al., 1977a, b). One of the most commonly applied Rock-Eval methods for determining quantities of petroleum expelled from a maturing source rock was developed by Cooles et al. (1986). The central assumption in this scheme is that a fixed fraction of organic carbon cannot be vaporized as volatile S_1 and generated S_2 products by Rock-Eval irrespective of the thermal-maturity level of a source rock. This fixed organic carbon is referred to as inert organic carbon. Another assumption in this approach is that gas generation is sufficiently negligible during petroleum formation to allow product yields to be equated to oil yields (Cooles et al., 1986). With these assumptions, quantities of expelled oil are determined by differences in product yields between immature and mature source rocks. The volatilized S_1 and generated S_2 hydrocarbon products are converted to carbon values (i.e., C_1 and C_2, respectively) by multiplying them by 0.85, which is the average carbon fraction of petroleum. Inert organic carbon (C_I) is calculated by subtracting the sum of C_1 and C_2 from the TOC of a source rock. An "o" superscript is used to denote organic carbon from immature source rocks that have not lost organic carbon as a result of petroleum or natural gas expulsion. An "m" superscript is used to denote organic carbon from mature or overmature source rocks that have lost organic carbon as a result of petroleum or natural gas expulsion. All of these organic carbon values are in units of grams of carbon per gram of source rock (g C/g Rx).

The first step in this approach is to determine the fraction of TOC that occurs as inert organic carbon in an immature source rock (i.e., X_I^o), which is determined by the expression

$$X_I^o = \frac{TOC^o - [C_2^o + C_1^o]}{TOC^o} \qquad (1)$$

The assumption that this fraction of inert organic carbon remains constant with increasing thermal maturity (i.e., $X_I^o = X_m^o$) allows the calculation of the original-immature TOC of a mature source rock (TOC^{om}) by the expression

$$TOC^{om} = \frac{TOC^m - [C_2^m + C_1^m]}{X_I^o} \qquad (2)$$

The difference between the TOC calculated for the original source rock (TOC^{om}) and that measured on the mature source rock (TOC^m) is considered the amount of organic carbon lost from the mature source rock as a result of petroleum expulsion ($TOC^{expelled}$)
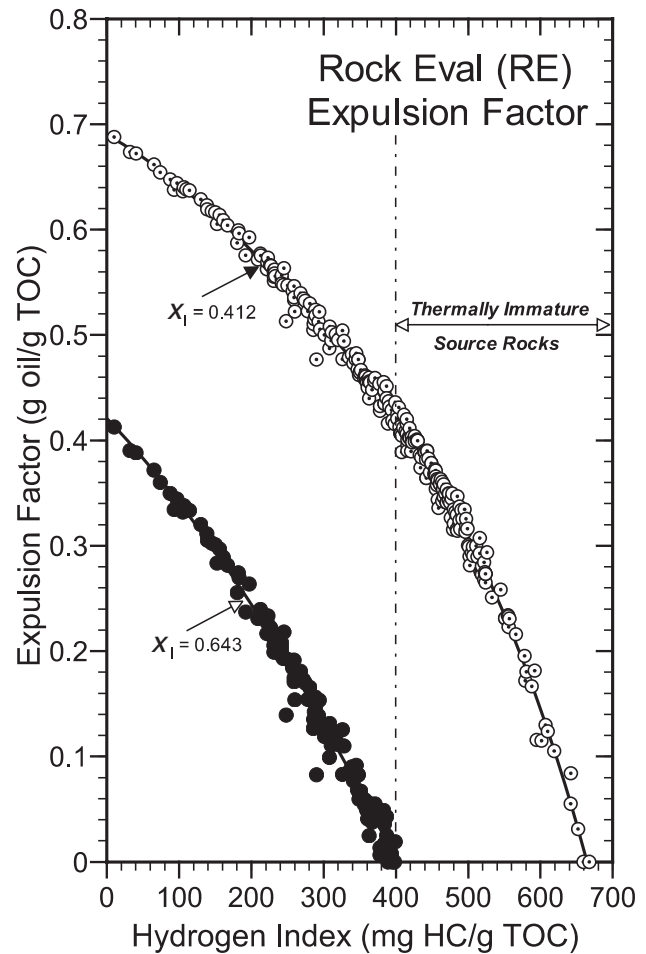
$$TOC^{om} - TOC^m = TOC^{expelled} \qquad (3)$$

This quantity may be divided by the original TOC of the mature source rock (TOC^{om}) to determine the grams of expelled carbon per gram of original TOC of the source rock. Dividing this quantity by the carbon fraction of petroleum (0.85) gives an expulsion factor in grams of oil expelled from a mature source rock per gram of original TOC in its original immature state (g oil/g TOC^{om}). The mass of oil is converted to barrels using an average oil density, which is 0.84076 g/cm^3 (API gravity of 36.8°), which is the mean density for produced oils in the Illinois basin (Mast, 1970).

The major problem with this approach is the invalid assumption that the fraction of inert organic carbon remains constant as a source rock thermally matures. Studies of source rocks that have been thermally matured in nature and by closed-system pyrolysis show that inert organic carbon increases significantly with thermal maturation (Evans and Campbell, 1979; Burnham, 1991; Lewan et al., 1995; Muscio and Horsfield, 1996). In addition to the invalidity of this assumption, deciding on a thermally immature sample from which to calculate a representative inert organic carbon fraction (X_I^o) is also problematic. As shown in Figure 5, thermally immature source rocks containing kerogen with essentially constant atomic H/C ratios have HI values that range between 400 and 700 mg HC/g TOC. Using equation 1, inert organic carbon fractions were determined from Rock-Eval results on the 125 samples of New Albany Shale from this study that fall within this immature range of HI values. Figure 14 shows a linear increase in the inert organic carbon fraction with decreasing HI, despite the lack of oil expulsion from these thermally immature samples. According to the linear regression line in Figure 14, the largest X_I^o is 0.643 at an HI of 400 mg HC/g TOC and the smallest X_I^o is 0.412 at an HI of 667 mg HC/g TOC. As demonstrated in Figure 15, these different inert organic carbon values make a significant difference in the resulting fraction of TOC that is expelled as oil from a source rock. The X_I^o of 0.412 gives a convex curve with a maximum expulsion fraction of 0.42g oil/g TOC for source rocks maturing from HI values of 400–0 mg HC/g TOC. The X_I^o of 0.643 gives a convex curve with a maximum expulsion fraction of 0.69g oil/g TOC for source rocks maturing from HI values of 667–0 mg HC/g TOC.
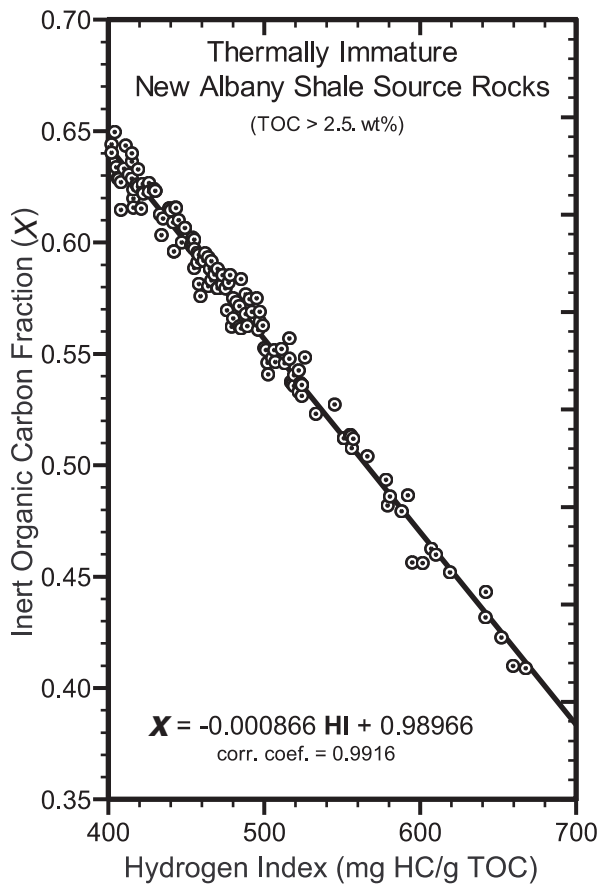
Figure 14. Plot of Rock-Eval HI vs. inert organic carbon fraction (X) of thermally immature source rocks of the New Albany Shale.

Figure 15. Plot of Rock-Eval expulsion factors (REEF) as calculated by the method described by Cooles et al. (1986) vs. HI of thermally immature source rocks of the New Albany Shale. The lower curve with solid data points represents expulsion factors calculated on thermally mature samples (HI < 400 mg HC/g TOC) with an inert carbon fraction of 0.643. This second-degree polynomial curve is empirically described by REEF = $(-8.27 \times 10^{-7})(HI)^2 - (7.185 \times 10^{-4})(HI) + 0.4209$. The upper curve with open data points represents expulsion factors calculated on all the samples (thermally mature and immature) with an inert carbon fraction of 0.412. This fourth-degree polynomial curve is empirically described by REEF = $(-3.67 \times 10^{-12})(HI)^4 + (2.954 \times 10^{-9})(HI)^3 - (1.353 \times 10^{-6})(HI)^2 - (3.665 \times 10^{-4})(HI) + 0.6898$.

Expulsion factors for each HI maturity interval are determined for both X_I^o curve expressions (Figure 15) using the midpoint for each of the HI maturity intervals (e.g., 325 for HI interval 350–300 mg HC/g TOC). The resulting expulsion fractions are multiplied by the original organic carbon values for each HI maturity interval (Table 2) and divided by the oil density of 0.84076 g/cm^3 to derive barrels of expelled oil for each catchment. Table 7 gives the petroleum charges by this method, which are 319 billion bbl for an X_I^o of 0.643 (minimum) and 1078 billion bbl for an X_I^o of 0.412 (maximum). In addition to both values being unrealistically large, the enormous difference between the maximum and minimum values (759 billion bbl) attests to the problems in employing this approach to material-balance assessments. Similarly, enormous quantities of expelled petroleum have been determined using this method in other material-balance calculations, which result in unrealistic and indefensible losses of hundreds of billions of barrels of oil from a

system (MacGregor and Mackenzie, 1987; Mackenzie and Quigley, 1988; Forbes et al., 1991; Lewan et al., 1995).

Hydrous Pyrolysis

Hydrous pyrolysis is a closed-system method that involves isothermally heating 200–500 g of gravel-size rock in the presence of liquid water at hydrostatic

Table 7. Petroleum Charge (10^9 bbl) Based on Rock-Eval Method of Each Catchment by HI Maturity Interval*

| Catchment No. | Hydrogen Index (mg HC/g TOC) Maturity Levels** ||||||||||||||||
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 400–350 || 350–300 || 300–250 || 250–200 || 200–150 || 150–100 || <100 || Total ||
| | Min | Max | Min | Max | Min | Max | Min | Max | Min | Max | Min | Max | Min | Max | Min | Max |
| 1 | 0.506 | 6.402 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.506 | 6.402 |
| 2 | 6.932 | 87.719 | 9.097 | 44.393 | 12.958 | 42.485 | 4.814 | 12.471 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 33.801 | 187.068 |
| 3 | 6.320 | 79.975 | 12.942 | 63.157 | 31.924 | 104.669 | 15.132 | 39.200 | 10.745 | 23.759 | 12.755 | 25.167 | 17.167 | 29.969 | 106.985 | 365.896 |
| 4 | 1.983 | 25.097 | 8.771 | 42.805 | 8.150 | 26.721 | 3.990 | 10.336 | 4.248 | 9.394 | 5.433 | 10.719 | 3.772 | 6.585 | 36.347 | 131.657 |
| 5 | 0.793 | 10.036 | 2.329 | 11.365 | 4.311 | 14.135 | 8.235 | 21.333 | 18.834 | 41.646 | 30.782 | 60.734 | 8.248 | 14.400 | 73.532 | 173.649 |
| 6 | 0.541 | 6.841 | 1.893 | 9.236 | 5.136 | 16.840 | 7.632 | 19.770 | 5.562 | 12.299 | 11.197 | 22.092 | 11.233 | 19.610 | 43.194 | 106.688 |
| 7 | 2.278 | 28.831 | 4.877 | 23.800 | 12.971 | 42.529 | 4.422 | 11.456 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 24.548 | 106.616 |
| Total | 19.353 | 244.901 | 39.909 | 194.756 | 75.450 | 247.379 | 44.225 | 114.566 | 39.389 | 87.098 | 60.167 | 118.712 | 40.420 | 70.564 | **318.913** | **1077.976** |

*Rock-Eval method from Cooles et al. (1986).
**Min = minimum petroleum charge based on an intial immature source rock having an HI = 400 and Xi = 0.643; Max = maximum petroleum charge based on an intial immature source rock having an HI = 668 and Xi = 0.412.

pressures (~64–200 bar) between 280 and 365°C for days to weeks. Expelled oil accumulates on top of the water surface in the closed reactor during heating and is quantitatively collected using a pipette after cooling to room temperatures (Lewan, 1993, 1997). In contrast to the Rock-Eval products that are enriched in NSO compounds (Behar et al., 1997), the expelled oils generated by hydrous pyrolysis are physically and chemically similar to natural crude oil (Lewan, 1997). A series of hydrous pyrolysis experiments were conducted on aliquots of a thermally immature sample of New Albany Shale to determine expulsion factors at different maturity levels (Lewan et al., 1995). This sample is organic rich (TOC = 14.34 wt. %) and thermally immature (R_o < 0.50; T_{max} = 425°C; production index = 0.03; HI = 604 mg HC/g TOC [Lewan et al., 1995]). Each of the experiments consisted of heating 300 g of crushed rock and 400 g of distilled water in 1 L reactors for 72 hr durations at constant temperatures between 270 and 365°C. The expelled oil was collected from the reactor using pipettes and solvent rinses as described by Lewan (1993).

Similar to the Rock-Eval expulsion factors, quantities of expelled oil generated by hydrous pyrolysis at each temperature are calculated as oil mass per mass of original TOC. The expulsion factors are related to atomic H/C ratios of kerogen isolated from the recovered rocks at each experimental temperature as shown in Figure 16. This relationship shows that the maximum expulsion factor of 0.29 g oil/g TOC occurs at an atomic H/C ratio of 0.67. Hydrous-pyrolysis expulsion factors can be related to hydrogen indices by combining the relationship shown in Figure 16 with the relationship between atomic H/C ratios of isolated kerogen and hydrogen indices of mature rock shown in Figure 5. The result of this computation is shown in Figure 17 along with the Rock-Eval expulsion factors from Figure 15 for comparison. Expulsion factors for the midpoint of each HI maturity interval (e.g., 325 for 350–300 mg HC/g TOC) are calculated from the relationship in Figure 17. Multiplying these expulsion factors by the mass of original immature organic carbon shown in Table 2 and dividing the product by an oil density of 0.84076 g/cm^3 yields the petroleum charge for each HI maturity interval by catchment (Table 8).

The total petroleum charge based on hydrous pyrolysis expulsion factors is 132 billion bbl (Table 8), which is significantly less than the 319 and 1078 billion bbl determined by the Rock-Eval expulsion factors
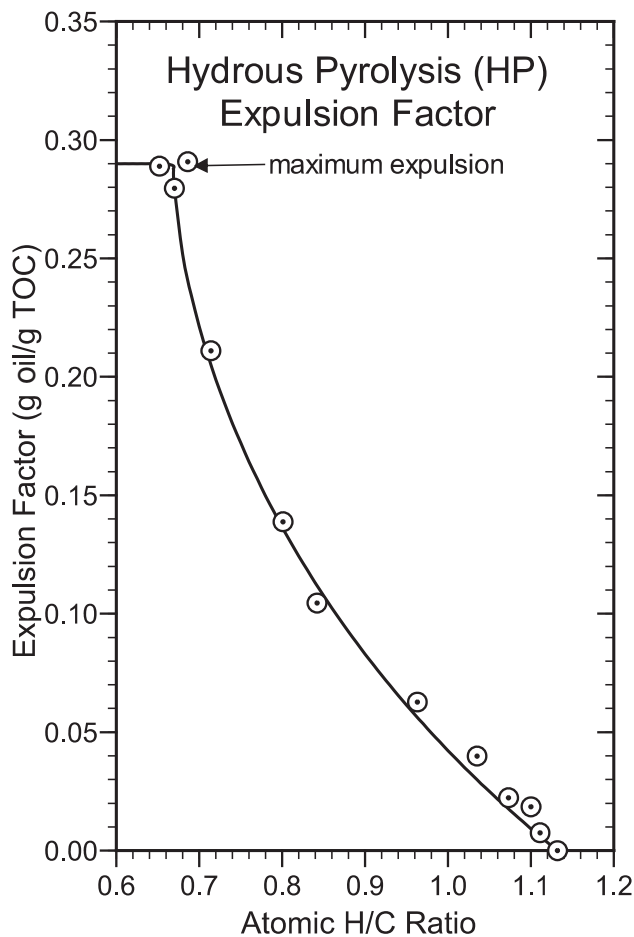
Figure 16. Plot of expulsion factors derived from expelled oil generated by hydrous pyrolysis (HPEF) vs. the atomic H/C ratio of the kerogen isolated from the recovered rock (Lewan et al., 1995). The concave curve is empirically described by HPEF = $0.2899 - 0.5058\{[1 - \exp(-(H/C) - (0.353) + (1.022))/0.959]^{0.589}\}$.

Figure 17. Plot of HI vs. hydrous-pyrolysis expulsion factors, (HP = $[-8.596 \times 10^{-9}][HI]^3 + [8.219 \times 10^{-6}][HI]^2 - [2.946 \times 10^{-3}][HI] + [416.06 \times 10^{-3}]$, for HI > 49.2 mg/g TOC), Rock-Eval expulsion factors (Figure 15), and actual expulsion factors (0.589[HP]).

(Table 7). Figure 17 shows two important differences between the expulsion factors determined by hydrous pyrolysis and Rock-Eval that contribute to differences in petroleum charge of these magnitudes. First, the maximum expulsion factors determined by Rock-Eval (0.42 and 0.69 g oil/g TOC) are larger than that determined by hydrous pyrolysis (0.29 g oil/g TOC). This difference is attributed to the inclusion of heavy NSO compounds in the vaporized product as a result of the high temperatures and low pressures employed by Rock-Eval. Behar et al. (1997) report that these components comprise more than 55 wt. % of the total Rock-Eval product for type II kerogen. Hydrous pyrolysis and natural oils are typically depleted in NSO compounds (<25 wt. %), which remain unexpelled in a maturing source rock as bitumen (Lewan, 1997).

Therefore, the Rock-Eval method developed by Cooles et al. (1986) gives higher maximum expulsion factors because of the inclusion of exaggerated quantities of NSO compounds relative to hydrous pyrolysis and natural oils.

The second difference is the shape of the expulsion factor curves (Figure 17). Hydrous pyrolysis expulsion factors increase with increasing thermal maturity in a concave manner consistent with prevailing petroleum-formation models (e.g., Tissot and Welte, 1984, figure II.7.10). Conversely, Rock-Eval curves are convex (Figure 17), which attributes greater quantities of expelled oil from source rocks at lower maturity levels. As an example, Rock-Eval expulsion factors indicate that 31% of the maximum quantity of expelled oil occurs from maturing source rocks in the

Table 8. Petroleum Charge (10⁹ bbl) Based on Hydrous Pyrolysis for Each Catchment by HI Maturity Intervals*

Catchment No.	Hydrogen Index (mg HC/g TOC) Maturity Levels															
	400–350		350–300		300–250		250–200		200–150		150–100		<100		Total	
	HP	1/2HP	HP	1/2HP	HP	1/2HP	HP	1/2HP	HP	1/2HP	HP	1/2HP	HP	1/2HP	HP	1/2HP
1	0.182	0.091	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.182	0.091
2	2.499	1.250	2.654	1.327	3.944	1.972	1.633	0.817	0.000	0.000	0.000	0.000	0.000	0.000	10.730	5.365
3	2.278	1.139	3.776	1.888	9.717	4.859	5.134	2.567	4.250	2.125	6.250	3.125	12.999	6.500	44.404	22.202
4	0.715	0.358	2.559	1.280	2.481	1.241	1.354	0.677	1.680	0.840	2.662	1.331	2.856	1.428	14.307	7.154
5	0.286	0.143	0.679	0.340	1.312	0.656	2.794	1.397	7.450	3.725	15.082	7.541	6.246	3.123	33.849	16.925
6	0.195	0.098	0.552	0.276	1.563	0.782	2.589	1.295	2.200	1.100	5.486	2.743	8.506	4.253	21.091	10.546
7	0.821	0.411	1.423	0.712	3.948	1.974	1.500	0.750	0.000	0.000	0.000	0.000	0.000	0.000	7.692	3.846
Total	6.976	3.488	11.643	5.822	22.965	11.483	15.004	7.502	15.580	7.790	29.480	14.740	30.607	15.304	132.255	66.128

*Hydrous pyrolysis from Lewan et al. (1995).

400–300 HI maturity interval. Hydrous pyrolysis expulsion factors indicate only 14% of the maximum quantity of expelled oil occurs for this same maturity interval. The greater expulsion factors determined by Rock-Eval at lower maturity levels is further accentuated by the common occurrence of source rock volumes increasing as concentric isomaturity zones increase outward from high to lower maturities in an active pod of source rock (e.g., Table 1; Figure 6).

Although the petroleum charge determined by hydrous pyrolysis is 2.4–8.2 times less than that determined by Rock-Eval, Lewan et al. (1995) contend that hydrous pyrolysis expulsion factors may also exaggerate the natural process of oil expulsion by a factor of two. This exaggeration of natural expulsion by hydrous pyrolysis is attributed to greater availability of water-derived hydrogen, reduced hydrostatic pressures, and greater thermal expansion of generated oil at the higher experimental temperatures (Lewan et al., 1995). This suggested exaggeration factor of two for hydrous pyrolysis reduces the total petroleum charge shown in Table 8 to 66 billion bbl of oil. It also suggests that the Rock-Eval petroleum charge is 4.8–16.4 times greater than that derived by natural expulsion.

Actual Charge

The spread in petroleum charges determined by laboratory pyrolysis techniques is enormous, with values ranging from 66 to 1078 billion bbl (Tables 7, 8). Although the petroleum charge values between 132 and 1078 billion bbl derived directly from laboratory pyrolysis techniques can be dismissed as unrealistic, the values between 66 and 132 billion bbl can be calibrated with respect to accountable petroleum and residual petroleum losses. This calibration requires determining which catchments are least likely to have lost petroleum as a result of erosion and leakage. As shown in the material-balance expression of Figure 1C, if the erosion and leakage losses equated to zero and there is no remaining in place oil to be discovered, then the sum of residual migration losses (Table 6) and accountable original oil in place (Table 3) of a catchment is equal to its petroleum charge. The absence of significant tar deposits related to the New Albany Shale indicates that petroleum losses resulting from leakage are essentially zero for all the catchments. Therefore, only catchments that have minimal erosional losses need to be considered in calculating a petroleum charge. Catchment 7 is the most favorable for this determination. This catchment has a minimal amount of eroded section (<500 m) as calculated by Cluff and

Byrnes (1990, figure 25-6) and no major faults through which vertical losses of migrating oil into eroded section can occur (Figure 7). In addition, no tar or oil accumulations occur in outcrops defining the updip extent of this catchment (Figure 11). With the stated assumptions, the petroleum charge for catchment 7 is the sum of the accountable in place oil (2.974 × 10⁹ bbl; Table 3) and residual oil lost (1.560 × 10⁹ bbl; Table 6). This actual petroleum charge of 4.534 × 10⁹ bbl is 58.9% of the hydrous-pyrolysis petroleum charge (7.692 × 10⁹ bbl; Table 8). Assuming this percentage can be applied consistently over all of the HI maturity levels as shown in Figure 17, an actual petroleum charge can be calculated for all of the catchments. Table 9 gives the actual petroleum charge for the different HI maturity intervals of each catchment. The total actual petroleum charge for the system is 78 billion bbl of oil.

Erosional Losses

As noted in Figure 1, petroleum losses are categorized as residual, leakage, and erosional. Residual petroleum losses in carrier beds have previously been determined and are given in Table 6. Similarly, leakage losses can be determined from the quantities of tar or heavy oil that occur in surface or near-surface deposits. Comparison of compositional parameters in an undegraded oil with its degraded equivalent tar or heavy oil allows one to calculate the quantity of oil lost as a result of degradation (e.g., Tannenbaum et al., 1987; Lewan et al., 1995). The quantities of remaining tar or heavy oil are included as accountable discovered in place oil, and the amount of oil lost as a result of degradation is considered leakage losses. As previously discussed, only traces of tar from the New Albany Shale occur in catchments 3 and 4. These trace quantities are not significant, so no leakage losses are considered in this material balance. Therefore, erosional losses are the only remaining petroleum losses to be considered in this material-balance assessment.

Although leakage losses of oil in the New Albany–Chesterian petroleum system are not significant, it is possible that tar deposits, carrier beds, and oil reservoirs in Upper Pennsylvanian–Permian section were lost through erosion. Thermal-history models based on vitrinite reflectance and moisture content of Lower Pennsylvanian coal indicate that 300 to more than 2500 m of Upper Pennsylvanian–Permian section was removed by erosion during the Mesozoic and Cenozoic (Damberger, 1971; Cluff and Byrnes, 1990). Petroleum formation from the New Albany Shale was well underway by the end of the Permian (Cluff and Byrnes, 1990), which makes it possible for petroleum to have migrated into carrier beds, traps, and seeps within the Upper Pennsylvanian and Permian sections. The likelihood of this possibility is supported by surface tar deposits in Pennsylvanian sandstones in western Kentucky and by shallow petroleum production from Pennsylvanian sandstones at shallow depths between 50 and 150 m in eastern Illinois and southern Indiana (Ball Associates, 1965). With the leakage losses for all the catchments being essentially zero, the difference between the petroleum charge and sum of accountable oil and residual oil loss equates to erosional losses (Figure 1C). This difference for each catchment is given in Table 10. Although the total erosional loss of 58 billion bbl for this petroleum system is enormous, 40 billion bbl of this loss are from two catchments (catchments 3 and 5). Erosional losses from the other five catchments are significantly smaller and range from 0 to 9 billion bbl of oil.

Table 9. Actual Petroleum Charge (10⁹ bbl) Based on Catchment 7 for Each Catchment and HI Maturity Interval

| Catchment No. | Hydrogen Index (mg HC/g TOC) Maturity Levels | | | | | | | |
	400–350	350–300	300–250	250–200	200–150	150–100	<100	Total
1	0.107	0.000	0.000	0.000	0.000	0.000	0.000	0.107
2	1.473	1.564	2.325	0.963	0.000	0.000	0.000	6.325
3	1.343	2.226	5.728	3.026	2.505	3.684	7.662	26.174
4	0.421	1.509	1.462	0.798	0.991	1.569	1.684	8.434
5	0.169	0.401	0.773	1.647	4.391	8.890	3.682	19.953
6	0.115	0.325	0.922	1.526	1.297	3.234	5.014	12.433
7	0.484	0.839	2.327	0.884	0.000	0.000	0.000	4.534
Total	4.112	6.864	13.537	8.844	9.184	17.377	18.042	**77.960**

Table 10. Calculated Erosional Losses for Each Catchment (10^9 bbl)

Catchment No.	Petroleum Charge*	Accountable In Place Oil**	Residual Oil Losses[†]	Leakage Losses[††]	Erosional Losses[‡]
1	0.107	0.012	0.095	0.000	0.000
2	6.325	3.446	2.098	0.000	0.781
3	26.174	2.870	3.050	tr	20.254
4	8.434	0.113	0.809	tr	7.512
5	19.953	0.000	0.038	0.000	19.915
6	12.433	2.011	1.325	0.000	9.097
7	4.534	2.974	1.560	0.000	0.000
Total	77.960	11.426	8.975	tr	57.559

*Values from Table 9.
**Values from Table 3.
[†]Values from Table 6.
[††]tr = trace leakage.
[‡]Values = Petroleum Charge − (Residual Losses + Accountable In Place Oil + Leakage Losses).

In evaluating the validity of these erosional losses, the degree of erosion and faulting in each catchment is considered. Degree of erosion is considered in terms of lateral and vertical components. The lateral component considers removal of Chesterian reservoir rocks, and the vertical component considers removal of Upper Pennsylvanian–Permian overburden. An index of the former is based on the percent of Chesterian rock eroded off mature New Albany Shale (i.e., within the 400 HI contour). As shown in Figure 7, Chesterian rock has been eroded off mature New Albany Shale in catchments 3, 4, 5, and 6. Surface-area percentages of Chesterian rock not present within the 400 HI contour of each catchment are given in Table 11, with erosional losses expressed in billions of bbl and percent of petroleum charge lost by erosion. An index for the vertical component is based on the mean thickness of eroded overburden within the 400 HI contour of each catchment (Table 11). This index was determined by superimposing the 400 HI contour on the total-erosion map constructed by Cluff and Byrnes (1990, figure 25-6). Area percentages of resulting polygons defined by erosional contours were used to determine a weighted mean thickness of eroded overburden in each catchment.

As shown in Figure 18, these two erosion indices correlate positively with one another and with the percent of petroleum charge lost by erosion. The empirical

Table 11. Geological Attributes Associated with Erosional Losses

Catchment No.	Erosional Losses* (10^9 bbl)	Percentage Charge Lost** (vol. %)	Mean Eroded Overburden[†] (m)	Percentage Eroded Chesterian[††] (within 400 HI)	Number of Major Faults[‡]	Faulting Intensity[‡‡] (m/km^2)
1	0.000	0.0	366	0.0	0	0.0
2	0.781	12.3	308	0.0	5	6.5
3	20.254	77.4	635	4.0	237	139.7
4	7.512	89.1	1,438	49.0	214	441.4
5	19.915	99.8	2,210	76.2	248	225.5
6	9.097	73.2	877	1.1	131	81.6
7	0.000	0.0	321	0.0	0	0.0
Total	57.559	73.8	871	21.0	835	147.0

*Values from Table 10,
**Values = (Erosional Losses/Petroleum Charge) × 100.
[†]Values are mean thickness of overburden eroded above mature source rock in the New Albany Shale (i.e., HI < 400 mg/g TOC).
[††]Percent of Chesterian surface area eroded within the 400 HI contour as shown in Figure 2.
[‡]Major faults as shown by Nelson (1990).
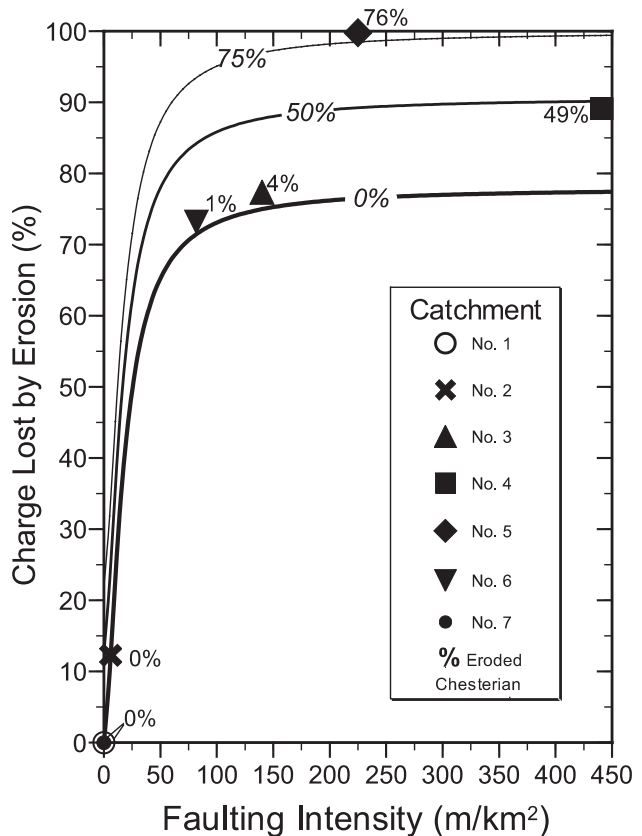[‡‡]Fault length per surface area of catchment.
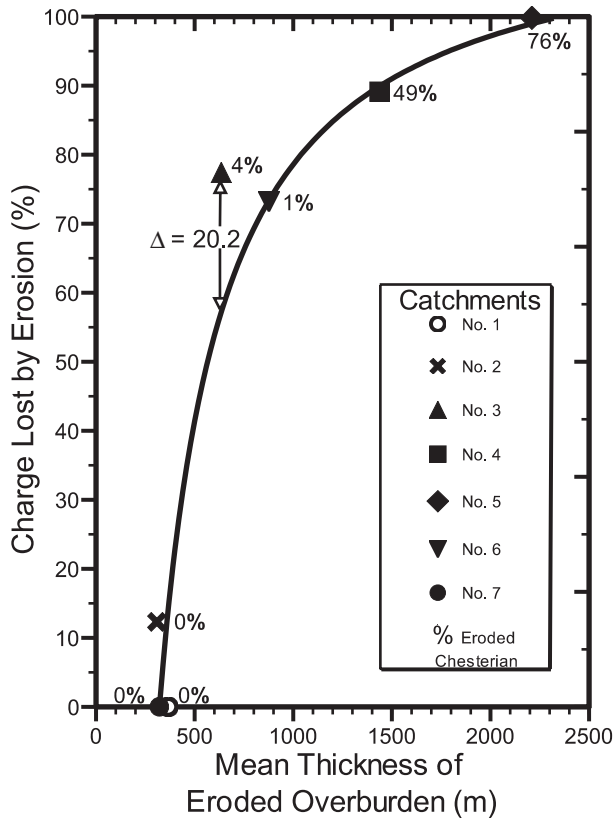
Figure 18. Percent of petroleum charge lost by erosion plotted against mean thickness of eroded overburden over mature source rock of each catchment. Percent values adjacent to points denote the percent of Chesterian surface area eroded off mature source rock in each catchment. The relationship between percent of petroleum charge lost by erosion (LE) and mean thickness of eroded overburden over mature source rock (EO) of each catchment is LE = 115.8 − (37202/EO). The Δ value is the percent of petroleum charge of catchment 3 that may be undiscovered in place petroleum.

hyperbolic function describing the relationship indicates that mean eroded overburden thicknesses less than 500 m are associated with erosional losses between 0 and 50% of the petroleum charge. Mean eroded overburden thicknesses greater than 500 m are associated with erosional losses between 50 and 100% of the petroleum charge. Not surprising is that catchment 5, which has erosional losses of 76% of the Chesterian and 2210 m of eroded overburden, has lost 100% of its petroleum charge. Conversely, catchments 1, 2, and 7, which have no erosional loss of Chesterian rocks and less than 400 m of eroded overburden, have lost less than 13% of their petroleum charge.

Faulting over and through mature source rock and its overburden are considered to enhance vertical migration of petroleum into higher stratigraphic levels,

which have since been eroded. An index of the degree of faulting was devised by measuring the length of major faults that occur over mature source rock (i.e., within the 400 HI contour) in each catchment, and then dividing this total fault length by the surface area of mature source rock (i.e., within the 400 HI contour) in each catchment. The resulting values are a measure of faulting intensity, and as shown in Table 11, they range from 0 m/km^2 in catchments 1 and 7 to 441 m/km^2 in catchment 4. Figure 19 shows that the percent of petroleum charge lost to erosion is significantly higher in the catchments that have greater faulting intensities. Admittedly, this index is an oversimplification of the many different attributes that may characterize a fault's ability to enhance vertical migration (Moretti, 1998). Catchments that have faulting intensities greater than 80 m/km^2, however, have erosional petroleum-charge losses greater than 70%, and catch-

Figure 19. Percent of petroleum charge lost by erosion plotted against faulting intensity over mature source rock of each catchment. Percent values adjacent to points denote the percent of Chesterian surface area eroded off mature source rock in each catchment. Curves are interpretive relationships representing percent isopleths of Chesterian surface area eroded off mature source rock.

ments that have faulting intensities less than 10 m/km^2 have erosional petroleum-charge losses less than 13%. The interpretive curves on Figure 19 depict different percentages of eroded Chesterian as they relate to faulting intensity. This interpretation suggests that faults have a significant effect on erosional losses between faulting intensities of 1 and 80 m/km^2 and, at higher faulting intensities, the amount of eroded section becomes the determinant factor.

Catchment Evaluation

The final material-balance values for the New Albany–Chesterian petroleum system (Table 10) show a total petroleum charge of 78 billion bbl, of which 11.4 billion bbl are accountable, 9 billion bbl are residual losses, and 58 billion bbl are erosional losses. Despite the more realistic (i.e., actual) petroleum charge used in this article, this petroleum system can be considered inefficient because only 15% of the charge occurs in economic accumulations. The true worth of the material-balance approach, however, lies in its application to the catchment subdivisions of the system. Catchments 3 and 5 received 59% (46 billion bbl) of the total petroleum charge, of which 87% (40 billion bbl) was lost because of extensive faulting and erosion. As a result, only 6% of the petroleum charge occurs as economic accumulations in these two catchments. The

remaining five catchments were charged with 38 billion bbl of oil, of which 23% occurs as economic accumulations. Catchments 2 and 7 were charged with only 14% (11 billion bbl) of the total petroleum charge, of which 59% (6.4 billion bbl) occurs as economic accumulations, which account for 56% of the total discovered in place oil for the whole system. Although the 15% trapping efficiency for the entire petroleum system is in the range of trapping efficiencies based on generated oil for other petroleum systems (e.g., 0.3–36.3 [Magoon and Valin, 1994]), the efficiency of trapping petroleum charge ranges significantly among the catchments from 0 to 66%.

Variations in the distribution of petroleum charge among accountable in place oil, residual oil losses, and erosional oil losses for each catchment can be represented as percentages on a ternary diagram, as shown in Figure 20. Catchments 2 and 7 occur in a region of the ternary diagram where more than 50% of their petroleum charge occurs as accountable in place oil (Figure 20). These catchments have no major faulting or eroded section to facilitate significant leakage or erosional losses of petroleum charge. In addition, oil production, hydrocarbon shows, and tar occurrences are not near or in the bordering outcrops of these catchments. Catchment 1 represents a catchment that accommodates more than 75% of its petroleum charge as residual oil losses. Similar to catchments 2 and 7,
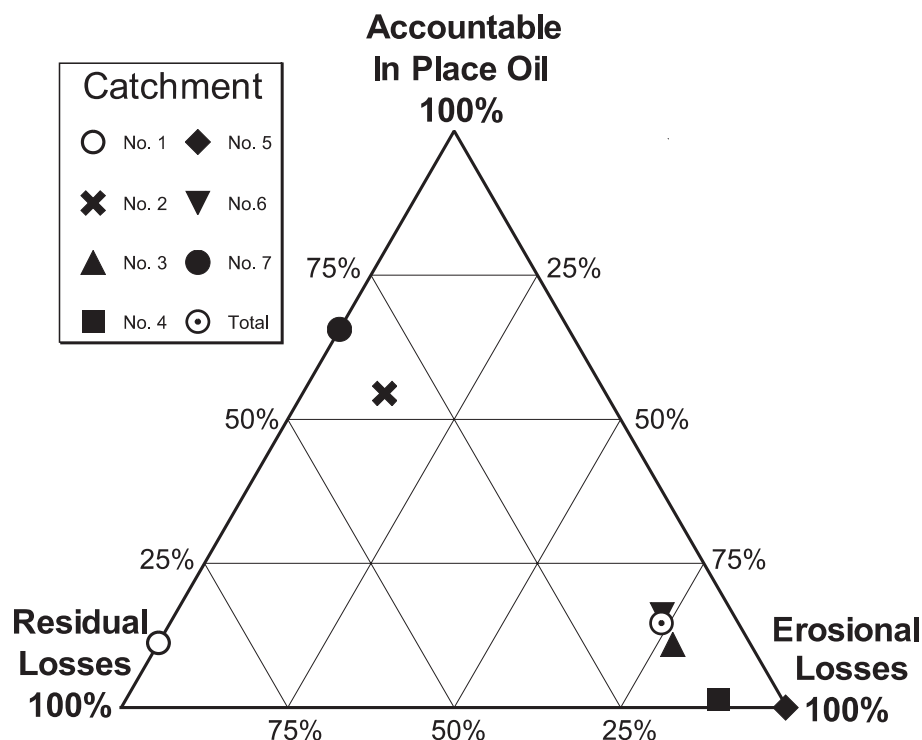
Figure 20. Ternary diagram of percent of actual petroleum charge distributed as accountable petroleum, residual petroleum lost during secondary migration, and erosional petroleum losses.

catchment 1 does not have major faulting or eroded section, and hydrocarbon occurrences do not occur near or in the bordering outcrops. This catchment is a result of a relatively small volume of mature source rock charging a significantly greater volume of catchment. Catchments 3, 4, 5, and 6 contain 44% of the discovered in place oil of the system and occur in a region of the diagram where more than 66% of the petroleum charge is lost in eroded section. These catchments have major faulting or eroded section, and hydrocarbon occurrences do occur near or in the bordering outcrops. Although this ternary distribution of charge among the catchments is specific to the New Albany–Chesterian system of the Illinois basin, it provides another perspective on evaluating petroleum systems and the fate of their petroleum charge.

One of the basic assumptions of this article is that there is no remaining petroleum to be discovered in the New Albany–Chesterian system of the Illinois basin. Although this assumption is reasonable on the basis of the assessment by Macke (1996), the final material-balance values can be reevaluated with respect to which catchments, if any, have some remaining potential for undiscovered petroleum. If there is undiscovered petroleum remaining in some of the catchments, it would most likely be included in the erosional losses. One approach to access the potential of undiscovered petroleum residing in the erosional losses is to find a relationship between erosional losses and a geological factor that suggests the erosional losses are anomalously high in a particular catchment. The relationship between percent of petroleum charge lost by erosion and thickness of eroded overburden (Figure 18) can serve in this capacity. As shown in Figure 18, the empirical relationship describes all of the catchments well, with the exception of catchment 3. Using this relationship, the erosional losses in catchment 3 may be interpreted as being anomalously high, and this may be attributed to undiscovered petroleum being included with the erosional losses. Assuming that the mean thickness of eroded overburden is accurate, 20.2% of the petroleum charge in catchment 3 should be undiscovered petroleum rather than charge lost by erosion. This percentage equates to 5.3 billion bbl of in place petroleum. Admittedly, this exact quantity is highly sensitive to the relationship used in Figure 18, but qualitatively this analysis suggests that catchment 3 has the best potential for undiscovered petroleum. According to the assessment by Macke (1996), undiscovered petroleum in the New Albany–Chesterian system would be limited to subtle stratigraphic traps, with the exception of two sizable unexplored areas. Interestingly, these two areas include counties in southwestern Indiana (i.e., Vanderburgh and Warrick counties) and western Kentucky (i.e., Breckinridge, Grayson, and Ohio counties) that occur in catchment 3. In addition, Montgomery and Leetaru (2000) have identified new reserves in the Storms Consolidated field and have suggested similar opportunities in surrounding fields, all of which occur in catchment 3. We do not suggest that exactly 5.3 billion in place bbl of undiscovered oil remain in this catchment, but instead that this catchment has the highest potential for undiscovered petroleum within this petroleum system.

CONCLUSIONS

As the material-balance approach is used in other well-drilled data-rich petroleum systems, a more quantitative understanding of petroleum occurrences will evolve for predicting undiscovered petroleum and the ranking of systems and their catchments. In this manner, catchments, rather than entire systems, can be used as analogs in assessing and ranking data-deficient areas. The following conclusions from this article are both general with respect to conducting material-balance assessments and specific to developing an understanding of the New Albany–Chesterian petroleum system.

1. Accurately delineating the pod of active source rock that has expelled oil into a petroleum system is critical. Maturity indices that are direct indicators of oil expulsion (e.g., atomic H/C ratio and HI) are preferred in delineating the pod of active source rock and its extent of oil generation. If HI values are used for this purpose, it is essential that a correlation between them and the atomic H/C ratio of kerogen be established to determine the onset of oil expulsion. The source rocks of the New Albany–Chesterian petroleum system that have HI values between 400 and 800 mg/g TOC show no correlation to thermal maturation or extent of oil generation. Only source rocks that have HI values less than 400 mg/g TOC show a relationship with atomic H/C ratios of kerogen and can be contoured to delineate the active pod of source rock and its extent of oil generation.
2. Variations in the TOC of immature source rock adjacent to a petroleum system can be used to predict original TOC of equivalent mature source rock.

This prediction is predicated on the verification by visual and $\delta^{13}C$ analyses of kerogens that the type of organic matter in the immature section is similar to that originally deposited in the mature section. Correlations of TOC with other attributes (e.g., paleoenvironment reconstructions, thickness variations, and well-log signatures) of immature source rocks can be extended to mature source rock in determining their original TOC. Source rocks in the New Albany–Chesterian system thicken by an order of magnitude from the immature periphery to the mature depocenter of the basin. A similar thickening of age equivalent immature source rocks in western Kentucky provided a correlation between mean TOC and thickness that was used to determine the original immature TOC values of the mature source rocks in the active pod of source rock.

3. Petroleum systems can be subdivided into secondary-migration catchments on the basis of buoyancy-driven migration. Although tortuous vertical and lateral pathways along fractures and faults or through porous rock may occur, the overall petroleum charge allocated to a catchment is maintained within its defined borders. Catchments include a prescribed volume of mature source rock and the adjacent rocks that have received its expelled oil. Therefore, a material-balance assessment can be applied to each catchment in terms of its own petroleum charge and losses. The New Albany–Chesterian petroleum system was divided into seven migration catchments by applying a hydrological surface-water–flow model to a contoured HI map of the New Albany Shale source rocks.

4. Migration catchments that have the greatest certainty in quantities of accountable petroleum and petroleum losses can be used to determine an actual petroleum charge. This charge can be used as a calibration standard for determining the petroleum charge of the other catchments in a petroleum system to evaluate their petroleum charge and losses. Catchment 7 in the New Albany–Chesterian petroleum system was the least likely to have significant erosional or leakage losses. An actual petroleum charge was calculated for this catchment and used to determine petroleum charges for the other catchments. The actual petroleum charge for the entire system is 78 billion bbl, with variations among the catchments ranging from 0.1 to 26.2 billion bbl.

5. Petroleum charge can not be determined directly from laboratory pyrolysis of source rocks. Laboratory pyrolysis exaggerates petroleum charge to dif-ferent degrees depending on the conditions and type of pyrolysis method used. Open-system and high-temperature conditions employed in Rock-Eval pyrolysis can yield petroleum charges in the range of hundreds of billions to more than a trillion bbl of oil. Closed-system and lower temperature conditions employed in hydrous pyrolysis can yield petroleum charges on the order of tens to more than a hundred billion bbl of oil. Total petroleum charge for the New Albany–Chesterian system as determined by Rock-Eval pyrolysis is 4–14 times higher than the actual petroleum charge. The petroleum charge by hydrous pyrolysis is only 1.7 times higher than the actual petroleum charge.

6. Residual losses can be reasonably estimated by identifying carrier beds and the extent of petroleum production and shows within a catchment. This surface area multiplied by 1–10% of the cross sectional thickness and porosity of the carrier bed gives an estimated volume of carrier bed that has experienced migrated petroleum. Using an experimentally determined residual oil saturation of 7.4%, the amount of residual oil lost as a result of secondary migration can be determined. Seven carrier beds with 0.5 m cross sectional thicknesses were evaluated for residual losses in the New Albany–Chesterian petroleum system. Residual losses accounted for only 11.5% (9 billion bbl) of the total petroleum charge for the system, with a range from 0.2 to 89% of the petroleum charge among the different catchments. These values probably represent maximum residual losses, because a considerable amount of secondary migration occurred through fractures and faults and residual oil saturations may be significantly lower than 7.4%.

7. Significant petroleum losses resulting from leakage are only justified if tar or heavy oil deposits occur at or near surface exposures within or bordering a catchment. Measurable quantities of degraded petroleum in heavy oil or tar deposits can be included with accountable in place petroleum. Geochemical oil-to-tar correlations are critical in this type of evaluation to insure that tar and heavy oil deposits truly belong to the petroleum system being studied. No major leakage losses are assigned to any of the catchments in the New Albany–Chesterian petroleum system. A geochemical correlation based on vanadium and nickel proportionality indicates that the large tar deposits of western Kentucky are not derived from source rocks in the New Albany Shale. Instead, these tars are derived from an unidentified

petroleum system, which is charged by a carbonate source rock.

8. Erosional losses are the most challenging of the petroleum losses to determine. Erosional losses are the difference between the actual petroleum charge and the sum of undiscovered petroleum, accountable petroleum, residual losses, and leakage losses. This erosional loss must be justified with respect to some geological factors related to erosion. If resulting erosional losses for a given catchment cannot be justified within the context of geological factors or are anomalously high relative to the other catchments of the system, this erosional loss may contain undiscovered petroleum remaining in the catchment. Although undiscovered petroleum in the New Albany–Chesterian petroleum system was initially assumed to be zero in this article, anomalous erosional losses in catchment 3 suggest that this catchment has the greatest potential for undiscovered petroleum.

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