Natural Gas Potential of the New Albany Shale Group (Devonian-Mississippian) in Southeastern Illinois

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Abstract
Data from geologic and geochemical studies of the New Albany shale group indicate that a 19-county area of southeastern Illinois is a favorable area to explore for gas in Devonian shale. Although gas shows in the shales have been encountered in several wells drilled in this area, no attempts were made to complete or evaluate a shale gas well until 1979.

In 1979, core samples from two Wayne County wells were obtained, permitting the first quantitative assessment of gas content of the shales in this area. Seventy core samples from the two wells were sealed in airtight canisters at the drilling site for off-gas analysis. The quantities of shale gas released from the core samples in a 34-day period ranged from 0.16 to 2.40 cu ft/HC/cu ft (0.16 to 2.40 m³/HC/m³) of shale. This gas is richer in heavy hydrocarbons than is the average "pipeline gas." It has a calculated average BTU value of 1,240 Btu/cu ft (46200 kJ/m³). Because the proportion of nonhydrocarbon gases is unknown, the calorific content of produced gas would necessarily be slightly lower. The gas-bearing intervals generally correspond with high radioactivity intervals on gamma-ray logs. The quantities of shale gas in core samples from these wells are similar to those in gas-producing areas of Devonian shale in the Appalachian basin. However, because the New Albany shale is much thinner than its Appalachian basin equivalents, the total gas resource is probably much smaller.

Conventional rotary drilling with mud base drilling fluids likely causes extensive formation damage and may account for the paucity of gas shows and completion attempts in the Devonian shales; therefore, commercial production of shale gas in Illinois probably will require novel drilling and completion techniques not commonly used by local operators.

Introduction
U.S. production of gas from Devonian black shales began in 1821 with the drilling of a well near Fredericksburg, N.Y. In the ensuing 161 years, production from Devonian shales has extended into eastern Kentucky, southern and western West Virginia, and scattered areas of Pennsylvania, Ohio, New York, western Kentucky, and Indiana. Currently, about 9,600 wells produce gas from shale in the Appalachian basin. One giant gas field, the Big Sandy field in eastern Kentucky, has produced more than 2 Tcf (5.6 x 10¹⁰ m³) of gas from Devonian shale.

The Devonian shales cover a broad area of northeastern U.S., extending westward into the Illinois basin, where they are called the New Albany shale group (Devonian-Mississippian). Although lithologically similar to the Devonian shales of the Appalachian basin, the New Albany has produced gas in only a few small areas of Indiana and western Kentucky. No gas production is known from the New Albany in Illinois. Because of the great lateral extent and thickness of the shales, however, resource estimates of the total gas that may be trapped within them are vast.

Producing gas from the shales has not been commercially attractive in the Illinois basin because of technological constraints (low production rates) and price regulations. If suitable technologies can be developed to recover the gas from these low-permeability reservoirs and thereby increase the productive capacity of wells, the Devonian shales might become an important source of natural gas in the future.

In mid-1976, the Illinois State Geological Survey began a detailed study of the geology and geochemistry of the New Albany shale in Illinois to evaluate its potential as a source of hydrocarbons, especially gas. This study, undertaken with partial support from the U.S. DOE Eastern Gas Shales Project, relied on studies of cores, drill-cutting samples, and geophysical logs to evaluate the regional geology of the New Albany shale.
Fig. 1—Cumulative thickness of radioactive black shale within the New Albany shale group in Illinois. Radioactive shale has a log value >60 API units above a normal shale base line.\(^6\)

...and identify the broad areas with the best potential for discovery of gas resources. In addition, U.S. DOE-funded drilling provided several cores of the New Albany Shale in Illinois and western Kentucky. Samples of these cores were collected to determine the quantity and the composition of the gas released from the shale. These data allowed an evaluation of the magnitude of the gas resource and helped identify zones that are most likely to be productive.\(^2\)

**Geologic Evaluation**

Previous studies of gas-bearing shales have shown that areas of gas production are related, at least partly, to four characteristics: regional facies patterns, areas of thick shale accumulation, the degree of thermal maturation of the organic matter in the shale, and the presence of extensive fracturing or faulting. Other factors also may be important, but they have not been well documented. Our preliminary evaluation of the New Albany shale in Illinois, using these four criteria, indicates that southeastern Illinois was the most favorable area for gas production.\(^3\)

**Depositional Facies**

Shale gas in the Appalachian basin usually is obtained from black to brownish-black, laminated, organic-rich shales.\(^1\) The gas in these shales originated from the thermal transformation (maturation) of the sedimentary organic matter dispersed throughout the shale matrix. Minor gas production from gray shales with low organic contents has been reported, but geologists generally believe that the gas originated in the black shales and migrated through natural fractures into the other zones. The dominant lithofacies of the New Albany shale are similar in most respects to the Devonian shales of the Appalachian basin.\(^4\)

The distribution of New Albany shale facies forms a roughly concentric pattern around the depositional center of the basin. The cumulative thickness of organic-rich black shales, as interpreted from gamma ray logs,\(^7\) is greatest near the center of the ancestral Illinois basin in southeastern Illinois and adjacent western Kentucky, and thins away from there in all directions (Fig. 1). Organic-poor, greenish-gray and olive-gray shales predominate in areas away from the basin center and are thickest in western and west-central Illinois. A broad transitional zone, where these two major facies belts interfinger and grade laterally into one another, trends northeast-southwest across central Illinois.

**Shale Thickness**

Harris et al.\(^9\) documented a close correlation between thickness of black shale accumulation and amount of gas production in the Appalachian basin. They found that areas with the best production coincided with areas where the black, organic-rich shales exceeded 490 ft...
(150 m) in thickness.

The entire New Albany group attains a maximum thickness of approximately 470 ft (143 m) in the Illinois basin (Fig. 2). Clearly, if the shale must be thicker than this for commercial production of shale gas, the entire Illinois basin must be considered unfavorable. There are two broad regions where moderately thick shale was deposited in the Illinois basin and improved completion techniques might permit recovery of gas from such areas.

One of these depocenters, located in Iowa and extending into western Illinois, is not considered a likely area for gas accumulations because of the paucity of black shale (Fig. 1). The southern depocenter, located in southeastern Illinois and western Kentucky, is a more likely area because it coincides with the area of greatest black shale accumulation (Fig. 2). The broad, thin area of New Albany sediments trending across central Illinois coincides with a transitional facies region having only marginal gas potential.

**Thermal Maturation**

Numerous studies on the origin of petroleum and natural gas have established that the transformation of sedimentary organic matter to mobile hydrocarbons depends on burial time and temperature. The chemical and physical properties of the disseminated organic matter change in a progressive and systematic manner as hydrocarbons are generated; this process is termed "maturation." Several methods can measure the relative maturity of a potential hydrocarbon source rock, and one of the best methods for organic-rich rocks is vitrinite reflectance.

The reflectance of light by vitrinite particles increases with increasing maturity and can be measured microscopically. Usually, a vitrinite reflectance level of at least 0.5% is needed for a rock to attain the "mature stage" (mainly generation of oil with some co-generation of gas), and a level of at least 1.2% is needed to attain the "supermature stage" (mainly gas generation). Fig. 3 is a map of isoreflectance values in the New Albany shale group, based on samples from more than 100 wells in Illinois. Only the areas on this map with a reflectance greater than 0.5% are likely to have significant potential for gas production, and those areas with the highest reflectances are probably the most favorable. Note that the areas where reflectance exceeds 0.5% generally coincide with the areas of thickest New Albany sediments and the areas with greatest accumulation of black shale.

**Faulting and Fracturing**

Natural fractures have been cited as a major pathway for gas migration and production in Appalachian gas fields. Although their nature and importance are debatable, it is likely that extensive fracturing aids the flow of gas into a well and increases the volume of shale drained by any single wellbore. Most of the major faulting in Illinois, including the Wabash Valley, Cottage Grove, and Rend Lake fault systems, the
Shawneetown fault zone, and the Fluorspar area fault complex occur in southern and southeastern Illinois (Fig. 4). Extensive fracturing of rocks in these areas is known to exist, as evidenced by observations in coal mines and by the significant production of oil from fractured reservoirs in the New Harmony field, White County.

Area of Greatest Gas Potential in Illinois

Our evaluation of the four major geologic criteria—depositional facies, shale thickness, thermal maturation, and known faulting and fracturing—indicates that a 19-county area of southeastern Illinois is geologically the most favorable area in Illinois for shale gas resources (Fig. 5). Although numerous oil and gas tests penetrate the Devonian shales in this region, especially in the northernmost counties, relatively few gas shows have been reported and there has never been any commercial production of gas from the shale. There are several possible reasons for the lack of gas shows in Illinois.

1. Virtually all Devonian tests in southern Illinois are drilled with rotary tools. In Indiana and western Kentucky most reported gas shows have been from cable tool holes, wherein gas shows are more noticeable.
2. Mud logging units are not widely used in Illinois.
3. Operators in Illinois tend to exhibit little interest in Devonian shales; therefore, there are probably many gas shows that have not been reported.
4. The Devonian shales beneath Illinois might not be gas bearing in many areas.

Except for a few inconclusive or negative drillstem tests of the Devonian shales in wells with gas shows, the producing potential of shale in southeastern Illinois was untested until recently. No data on gas release from shale cores were available that could be used to estimate the quantity of gas contained in the shale, or the most favorable stratigraphic zones for gas production. Without additional data on gas content or gas production, a geological evaluation must be limited to identifying broad areas that might hold gas.

Analysis of Released Gas

In May 1979, Hobson Oil Co. cored 16 ft (5 m) of the uppermost New Albany shale in their No. 2 Taylor test (Sec. 34, T.1 S., R.7 E., Wayne County, IL). Four samples were removed on-site from this core for off-gas analysis. In Sept. and Oct. 1979 the U.S. DOE (through its subcontractor Gray Federal Inc.) funded coring of the entire New Albany shale group in the Gordon T. Jenkins No. 1 Simpson test (Sec. 17, T.3 S., R.8 E., Wayne County, IL). Sixty-six samples were removed for off-gas analysis from the 235 ft (72 m) of Devonian shale recovered. These two cores provided the first data with which a more conclusive assessment of the gas potential of the New Albany shale in southeastern Illinois could be made.

Methods of Gas Analysis

Samples were collected at each coring site and sealed in airtight, reusable aluminum canisters for off-gas analysis. The time elapsed between coring the samples
TABLE 1—RELEASED GAS ANALYSIS AND HYDROCARBON COMPOSITION, HOBSON OIL NO. 2 TAYLOR CORE, WAYNE COUNTY, IL

<table>
<thead>
<tr>
<th>Depth to Top of Sample</th>
<th>Off gas (m^3 HC/m^3 shale)</th>
<th>C1 methane (%)</th>
<th>C2 ethane (%)</th>
<th>C3 propane (%)</th>
<th>C4 butane (%)</th>
<th>C5 pentane (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>4,834</td>
<td>1474</td>
<td>0.73</td>
<td>76.81</td>
<td>16.89</td>
<td>4.17</td>
<td>1.28</td>
</tr>
<tr>
<td>4,838</td>
<td>1476</td>
<td>0.82</td>
<td>72.78</td>
<td>18.30</td>
<td>6.38</td>
<td>1.99</td>
</tr>
<tr>
<td>4,843</td>
<td>1477</td>
<td>0.66</td>
<td>72.11</td>
<td>18.97</td>
<td>6.38</td>
<td>2.00</td>
</tr>
<tr>
<td>4,846</td>
<td>1478</td>
<td>0.55</td>
<td>72.57</td>
<td>18.38</td>
<td>6.43</td>
<td>2.04</td>
</tr>
<tr>
<td>Averages</td>
<td></td>
<td>0.69</td>
<td>73.56</td>
<td>18.13</td>
<td>5.97</td>
<td>1.82</td>
</tr>
</tbody>
</table>

and sealing them in canisters varied from 4 to 6 hours, depending on the trip time out of the borehole and the time required to break down the core barrel, remove the core, and make a brief lithologic description. The time of sealing, the air temperature, and the barometric pressure were recorded; then the sample canisters were transported to the laboratory to be stored at constant temperature (20°C).

The headspace pressure in each canister was monitored weekly until a relatively constant equilibrium pressure was attained. We calculated the quantity of gas released by each sample by Boyle's law, using the final, stable headspace pressure. We determined the volume of headspace by weighing the volume of water displaced by the core sample and subtracting it from the known canister volume.

A portion of the gaseous hydrocarbons contained within the shale at its normal burial depth probably was lost before the samples were sealed within their canisters because of the sudden drop in confining pressure as the core is brought up to the surface and the relatively long period between coring and sampling. The quantity of gas released from core samples therefore should be considered minimal values, and the actual in-situ gas content may be too to four times greater.

A small sample of gas was removed periodically by a hypodermic needle inserted through a rubber septum in each canister. Gas compositions for these samples were determined by gas chromatography using a dual phase column for the separations. A Perkin-Elmer Sigma 1™ gas chromatograph system was used to analyze the headspace gas. A Perkin-Elmer: Sigma 10™ data processor was used to integrate peak areas and calculate both the total headspace gas and the hydrocarbon-only compositions from a single sample injection. A typical gas chromatogram for a New Albany shale sample is shown in Fig. 6.

G.T. Jenkins No. 1 Simpson Core, Wayne County

Because of the favorable indications of gas observed in the Hobson Oil well, the Illinois Survey urged the U.S. DOE to give high priority to funding a complete New Albany core in Wayne County or some adjacent area of southwestern Illinois. Subsequently, G.T. Jenkins agreed to core the entire New Albany shale in his No. 1 Simpson test, just north of the town of Mill Shoals near the southern Wayne County border. A complete section of the New Albany, with several feet (meters) of overlying and underlaying strata, was cored in this well during late September and early October of 1979. Sixty-six samples taken at approximately 3-ft (1-m) intervals were collected for off-gas analysis. The quantity of gas released after 34 days ranged from 0.16 to 2.40 cu ft HC/cu ft (0.16 to 2.40 m^3 HC/m^3) of shale. The zones of shale with the highest gas content usually coincided with the zones of high radioactivity (Fig. 7). Several sample canisters leaked for various reasons; therefore, the gas content of samples within the highest gamma-ray interval of the Grassy Creek shale near 5,100 ft (1560 m) (Fig. 7) could not be determined accurately. Several black shale intervals of the Selinier shale were relatively gas rich, while the Blocher shale, a finely laminated, calcareous black shale at the base of the New Albany group, contained little gas (Fig. 7). The low gas contents at the base of the New Albany group suggest that the gas did not migrate into the shale from an underlying, undiscovered hydrocarbon reservoir.

The composition of the released hydrocarbons varied only slightly with stratigraphic position within the shale (Fig. 7). On the average, the gas comprised 70% methane, 19% ethane, 8% propane, 2% butane, and 1% heavier hydrocarbons. This gas is richer in heavy hydrocarbons than typical pipeline gas. The calculated calorific content of New Albany gas in Wayne County is 1,240 Btu/ft^3 (46 200 kJ/m^3), which includes the four gas analyses from the Hobson Oil core. The actual calorific value of the produced gas would be slightly lower because an unknown percentage of carbon dioxide, nitrogen, and other nonhydrocarbon gases probably would be present. Jenkins did not attempt to complete this well as a gas producer, but plugged back into a higher, oil saturated zone.

Hobson Oil No. 2 Taylor Core, Wayne County

In May 1979, Hobson Oil cut a New Albany shale core in north central Wayne County. This core provided the first positive evidence that the New Albany shale contains significant quantities of gas in an area of Illinois. Sixteen feet (5 m) of core were recovered from the top of the New Albany group, all within a dominantly black shale formation known as the Grassy Creek shale. The entire length of the core was split by a single, near-vertical fracture, which resulted in severe jamming of the core barrel and prevented further coring. The gas released by four samples collected from this core ranged from 0.55 to 0.82 cu ft HC/cu ft (0.55 to 0.82 m^3 HC/m^3) of shale. The gas was very wet, with more than 25% ethane and heavier hydrocarbons (Table 1).

Hobson Oil hydraulically fractured the New Albany shale and attempted to complete the No. 2 Taylor well as a gas producer; however, excessive water production, probably the result of poor casing cement bond, resulted in abandonment of the fractured interval.
Fig. 7—Released-gas analysis and core lithology, G.T. Jenkins No. 1 Simpson core, Wayne County, IL.
Fig. 8—Released-gas analysis and core lithology. Northern Illinois Gas No. 1 RAR core, Henderson County, IL.
Fig. 9—Released-gas analysis and core lithology, Northern Illinois Gas No. 1 MAK core, Tazewell County, IL.
Other New Albany Shale Cores in Illinois

Three cores of the New Albany shale had been acquired previously in western and central Illinois as part of our research. For the most part, these cores identified broad areas where the New Albany has little or no potential for commercial production rather than identifying areas where gas does occur. The two northernmost cores, located in Henderson and Tazewell Counties (Fig. 5), had no gas shows and released insignificant quantities of gas—less than 0.05 cu ft HC/cu ft (0.05 m³ HC/m³) of shale. Although these quantities were very small, the amount of gas released correlated closely with the gamma-ray intensity (Figs. 8 and 9).

The third core was drilled at the northern edge of Louden oil field in Effingham County, IL (Fig. 5). This core was located where the New Albany is thin in an area just outside the 19-county area previously outlined as having favorable geologic characteristics for gas. Although moderate amounts of gas were released by the core samples [generally below 0.5 cu ft gas/cu ft (0.5 m³ gas/m³) of shale] (Fig. 10), isotopic analyses suggest that the gas is not indigenous to the shale but rather that it migrated upward from the underlying Devonian oil reservoir. 16

Conclusions

The analysis of two cores from southeastern Illinois generally confirms the assessment of the gas potential of the New Albany shale, 3 which was based on stratigraphic and petrographic interpretations alone. These cores demonstrated that the New Albany contains gas in at least some areas of southeastern Illinois. The quantity of gas released compares favorably with gas-producing areas in the Appalachian basin, where gas contents of 1.0 cu ft HC/cu ft (1.0 m³ HC/m³) of shale are common. Geologic data and off-gas analysis of three cores from these outlying areas indicate that broad areas of the Devonian shales in Illinois probably have little or no potential for commercial production of gas. The total Devonian shale gas resource of any given area in Illinois is probably much less than that of a similar-size area in the Appalachian basin because the New Albany is much thinner and the level of thermal maturation is generally lower. The total resource still may be appreciable; however, in our estimation a quantitative assessment of the resource is premature because of limited data.

The widespread use of conventional rotary drilling with high-density mud-base drilling fluids in Illinois constitutes a major problem in evaluating the commercial potential for gas production from the New Albany shale. Drilling muds cause extensive formation damage to ultralow-permeability reservoir rocks such as shale, where even minor blockage of the few high-permeability pathways available (including natural fractures) would inhibit flow greatly. The gas trapped within shales is released slowly and at low pressures; thus, the reservoir lacks the energy necessary to clean itself of drilling-induced damage. Unpublished studies in Kentucky and Indiana have shown that the proportion of natural gas shows in the Devonian shales is much higher in holes drilled with cable tools than in holes drilled with rotary tools. This suggests the possibility that drilling with cable tools and water or drilling with air may be the most satisfactory methods for drilling Devonian shale tests. Because of the numerous water-saturated porous zones in the overlying Mississippian and Pennsylvania, such techniques probably would require that a casing string be set before drilling into the New Albany shale.

Furthermore, conventional drillstem testing of shales is probably of little value. Drillstem tests are of short duration and involve limited quantities of fluids; they are most satisfactory when evaluating rocks with high porosity and high permeability. Production testing of Devonian shales should take several days or even weeks and most likely will require some type of stimulation technique, such as massive hydraulic fracturing. The expense and risk of setting casing and stimulating the shale to evaluate its potential for production undoubtedly will
be major barriers to the development of this potential, but as yet untapped, resource.

References


SI Metric Conversion Factors

\[
\begin{align*}
\text{cu ft} & \times 2.831 \text{ 685} & \text{E-02} & = \text{m}^3 \\
\text{ft} & \times 3.048* & \text{E-01} & = \text{m} \\
\text{mile} & \times 1.609 \text{ 344}* & \text{E+00} & = \text{km}
\end{align*}
\]

*Conversion factor is exact.