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Delineation of the Coalbed Methane Resources of Illinois

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Illinois Department of Natural Resources
ILLINOIS STATE GEOLOGICAL SURVEY
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Disclaimer

Front Cover: *On-site gas desorption unit. After retrieval, coal core samples are placed in the on-site desorption unit as quickly as possible. The samples are sealed in airtight canisters, pressure is gradually reduced to extract methane, and the released gas volume is carefully measured at timed intervals. After the released gas is collected, it is analyzed to determine its quantity, quality, and origin.*

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William W. Shilts, Chief
615 E. Peabody Drive
Champaign, Illinois 61820-6964
217-333-4747
www.isgs.uiuc.edu

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Abstract

Coalbed methane (CBM) will likely meet a significant portion of the increasing U.S. demand for natural gas for the next several decades. Of the approximately 284 billion tons of coal in the Illinois Basin, 211.4 billion tons are in Illinois. Previously the state's commercial coal gas production has been restricted to relatively small amounts of coal mine methane production, but recent advances in exploration and production technologies and rising gas prices have renewed interest in initiating commercial projects to increase coal gas production in the state.

For our research project, five wells were drilled and continuously cored to identify and sample coal seams and some shales for gas data and to delineate Pennsylvanian stratigraphy in diverse geographical areas of Illinois. Excluding anomalously low values from the northernmost Bureau County well, the coals contained 37 to 173 standard cubic feet per ton (scf/t) of gas and the shales contained 52 to 145 scf/t of gas on a dry, mineral matter-free basis. Gas contents of multiple seams in a single well and of a given coal seam among multiple wells generally increased as coal rank and depth increased. The CBM resources of the Illinois Basin were estimated to be 21 to 25 trillion cubic feet (Tcf), at least 14 Tcf of which are expected to occur in Illinois. Digital maps generated by the project delineated the thickness, depth, rank, elevation, and cleat directions of coals, tectonic structures, and mined-out areas in Illinois, which can aid in determining the state's important CBM reserve areas. Future studies should involve hydrogeological mapping and development of CBM well completion and stimulation techniques suitable for Illinois Basin coals. It is essential to evaluate systematically various CBM recovery techniques, such as advanced hydraulic fracturing, horizontal drilling, open hole cavitation, and carbon dioxide injection, for their applicability to Illinois coals.

Introduction

By 2025, U.S. demand for natural gas is expected to exceed 32 trillion cubic feet (Tcf) annually, an increase from its current level of about 23 Tcf (Energy Information Administration 2003). This increase is expected to be mostly due to the increasing share of natural gas in electricity generation by newly built power plants. Currently, 95% of the new power plants and more than 50% of homes in the United States are fueled by natural gas (Pinsker 2002), and coalbed methane (CBM) is likely to play a large role in meeting increasing natural gas demand over the next few decades. Proven U.S. CBM reserves have steadily increased from less than 4 Tcf in 1989 to 18.5 Tcf in 2002, providing 1.61 Tcf of gas production in 2002 (fig. 1). As a result, CBM accounted for 9.9% of proven reserves and 8% of the production of dry natural gas in the United States for 2002 (Energy Information Administration 2003).

A number of incentives, including federal tax credits, surging gas prices, and declining conventional reserves of natural gas, prompted increased CBM exploration and production activities in the United States since the mid-1980s. The availability of well-mapped coal seams, longer production life of CBM wells, and generally shallower reservoir depths relative to conventional gas production add to the economic attractiveness of CBM use. Furthermore, CBM production has industrial safety and environmental benefits, namely, reduced gas explosion risk in coal mines and lower atmospheric emission of methane (CH_4), a much stronger greenhouse gas than carbon dioxide (CO_2).

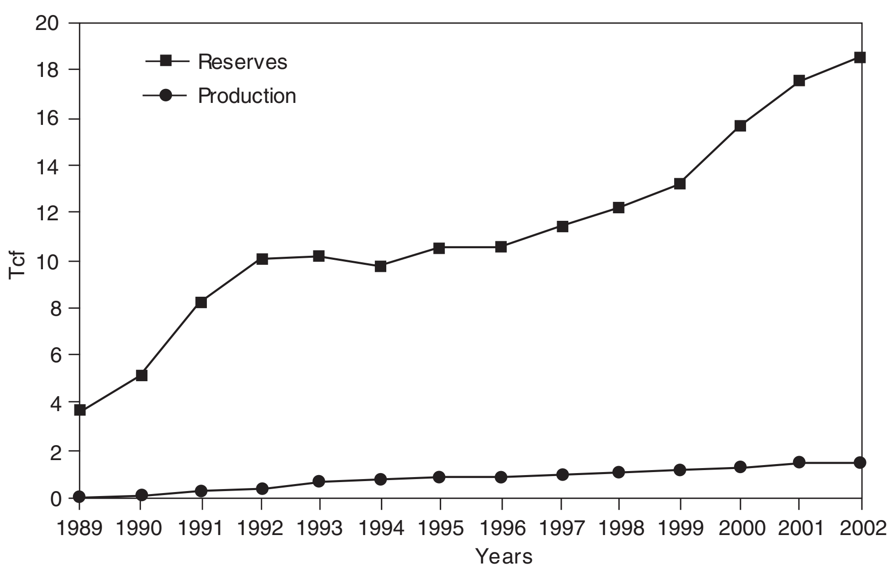

Figure 1 U.S. proven reserves and production of coalbed methane in trillion cubic feet (after Energy Information Administration 2003).

Accidental explosion of CBM in underground coal mines has always been a safety issue. Methane buildup in mine air can go undetected without the use of adequate monitoring techniques because methane has half the density of air, no toxicity, no odor, no color, and no taste. Explosions can occur when methane concentration reaches 5 to 15% in mine air, and mining regulations have long required that methane in mine air be diluted to <1% through ventilation. Active coal mines in the United States released 187 billion cubic feet (Bcf) of methane in 2000, of which 36 Bcf was recovered and used (U.S. Environmental Protection Agency 2002). Methane, a greenhouse gas, has a much shorter residence time in the atmosphere than the main greenhouse gas, carbon dioxide (Kruger 1991, U.S. Environmental Protection Agency 2002), and the amount of methane emitted from coal mines is much less than the amount of carbon dioxide emitted from fossil fuel combustion. However, on a per unit mass basis, the greenhouse effect of methane is 21 times greater than that of carbon dioxide over a 100-year period.

The history of CBM development in the United States is an uneven one, characterized by an initial focus on the San Juan Basin in New Mexico and the Black Warrior Basin in Alabama. Production in other areas suffered from a variety of technical and economic barriers, often related to applying one reservoir development model taken from successful operations in these basins to other areas without much consideration for local conditions. Other regions were then viewed as uneconomical or as lacking gas potential. However, since 1997, the most rapidly developing CBM resource is in the Powder River Basin of Wyoming, a region given hardly any potential just seven years ago. In 2001, 7,000 wells in the Powder River Basin were producing a total of 700 million cubic feet of coal gas per day (Pinsker 2002). Experience in the Powder River Basin, the Uinta Basin of Utah, and the Raton Basin of Colorado/New Mexico, all of which have undergone extensive CBM development in the past five years, has shown that local conditions must be thoroughly understood to achieve successful economic development. Gas content, coal permeability and composition, and water production and quality are a few of the numerous factors that need to be identified and locally understood.

This report (1) reviews the basic aspects of CBM and previous work on coal and CBM resources of Illinois and (2) discusses new findings from a current project that involved drilling, gas content measurements, coal characterization, and digital mapping. In this report, both CBM and methane gas in coal refer to coalbed methane, and the terms are used interchangeably. The term “coal gas” is used to express the total gas in coal and includes CH_4, wet gases (C_{2+}), nitrogen gas (N_2), and CO_2. Wet gases include gases of multi-carbon molecules such as ethane, propane, or butane. Coal mine methane (CMM) refers to methane liberated from active mines or accumulated in abandoned underground mine space.

General Technical Background

Origin of CBM

Coal and CBM are the products of the same geological processes. Coal is derived from plant material deposited in ancient peat swamps and then altered over time through geochemical processes. Two distinct processes give rise to CBM: biochemical processes (biogenic methane) and thermal processes (thermogenic methane). Although biogenic methane may constitute only 10% or less of total methane generated by coal during its geological history (Rightmire 1984), it can be a much larger component of the gas that is actually retained in coal depending on the amounts of thermogenic gas loss and biogenic gas generation after the formation of coal.

Biogenic Methane Biogenic CBM results from the biochemical degradation of organic material early during the peat stage or later during the exposure of coal to bacterial activity. The early-stage biogenic CH_4, which is referred to also as swamp or marsh gas, is generated in significant quantities when the peat environment is anoxic and has low sulfate concentrations, low temperatures, high pH values, adequate pore space, and rapid sedimentation rate (Zhang and Chen 1985, Rice 1993). This complex and often poorly understood process involves many species of bacteria and many different combinations of chemical reactions.

In a peat swamp, the plant material is biodegraded first by aerobic bacteria and fungi that use organic matter as a food supply and consume free oxygen from air or in solution. This process partially oxidizes plant material and thus generates CO_2. As oxygen is used up by aerobic bacteria and as the circulation of free oxygen is prevented by the increasing burial of peat, aerobic bacteria are replaced by anaerobic bacteria. Most anaerobic bacteria can meet their oxygen needs by stripping oxygen from CO_2 and/or organic matter (a reduction process), leading to hydrogen-rich products and the carbon-hydrogen reactions that form CH_4. This mechanism of biogenic CBM generation is known as the CO_2 reduction process. A few species of anaerobic bacteria can generate CH_4 directly through methyl-type “fermentation” in which carboxyl and methyl groups of acetate and perhaps other substrates were directly converted to CO_2 and CH_4, respectively, at near surface conditions. Most of the early-stage biogenic gas is probably dissolved in water and expelled from the peat during compaction because of low pressure and the occupation of many potential gas sorption sites in the peat material by water molecules (Scott et al. 1994).

Biogenic CH_4 also can be generated after coal is formed and then is exposed to bacterial activity through groundwater circulation. Tectonic uplift, erosion, and sufficient permeability after burial and coalification can facilitate the circulation of bacteria-bearing meteoric waters through coal beds. Late-stage biogenic CH_4 generation probably starts with the aerobic oxidation, which eliminates dissolved oxygen in the water and provides nutrients for the anaerobic bacteria (Rice 1993). The bacteria metabolize wet gases, *n*-alkanes, and other organic compounds in coal or other organic-rich rocks at temperatures generally below 150°F to generate late-stage CH_4 and CO_2 (Scott et al. 1994). This late-stage or secondary biogenic CH_4 probably constitutes most of the biogenic CBM retained in coal.

Thermogenic Methane Most methane generation by coal or its precursor material occurs through thermal processes at significant burial depths over geologic time or as a result of exposure to heat from magmatic sources. The thermal effect also is responsible for coalification, a process by which peat is gradually converted to lignite, sub-bituminous coal, bituminous coal, and then to anthracite. Increasing pressure during progressive burial contributes to coalification by compacting the plant material and driving off water and volatiles. Coalification is basically a devolatilization and concomitant aromatization of the peat, a largely humic material of oxygen-rich lignin and cellulose. Organic molecules are thermally cracked, releasing their oxygen as water (H_2O) and CO_2, nitrogen as N_2, and hydrogen as H_2O, CH_4, and heavy oil, leaving behind a more aromatic solid product.

The "coalified" solid organic matter is not a homogeneous material, but rather is composed of distinct components called macerals. There are three groups of macerals: (1) vitrinites, derived mostly from woody parts of plants; (2) liptinites, derived mainly from waxes, spores, and cuticles of plants; and (3) inertinites, derived mostly from the plant parts that were charred as a result of fire or extensive low-temperature oxidation. The liptinite macerals and their precursors have high contents of aliphatic (hydrogen-rich) compounds, and thus their thermogenic CH_4 yield is expected to be greater than that of vitrinites (moderate CH_4 source) and inertinites (poor CH_4 source). Starting with high-volatile bituminous coal stage, the thermogenic CH_4 generation increases rapidly as rank increases (fig. 2). Substantial amounts of wet gases are also generated from the hydrogen-rich components in coal during the high-volatile bituminous coal stage (Scott 1994; Scott et al. 1994). Laboratory pyrolysis data suggest that the threshold of significant thermogenic CH_4 generation occurs when coal reaches the high-volatile bituminous A rank (Tang et al. 1991, Scott et al. 1994, Scott 2002).

Coal as a Methane Gas Reservoir

Coal is different from conventional natural gas reservoirs in the sense that it is both the source rock and the reservoir rock for CH_4 gas; that is, coal can generate and trap its own gas. In addition, gas generated during oil formation in strata lying well below the coal seams can migrate upward and be stored in coal seams. Increasing aromaticity of coal during coalification increases its microporosity and internal surface area, which, in turn, are desirable for retaining methane. Internal surface areas reported for Illinois coals (Thomas and Damberger 1976, Demir et al. 1994) range from 46 to 292 m²/g. Demir et al. (1994) found for samples in the Illinois Basin Coal Bank Program that the internal surface areas in micropores increased while those in larger pores decreased as coal rank increased. In contrast to conventional natural gas reservoirs, coal has very little macroporosity.

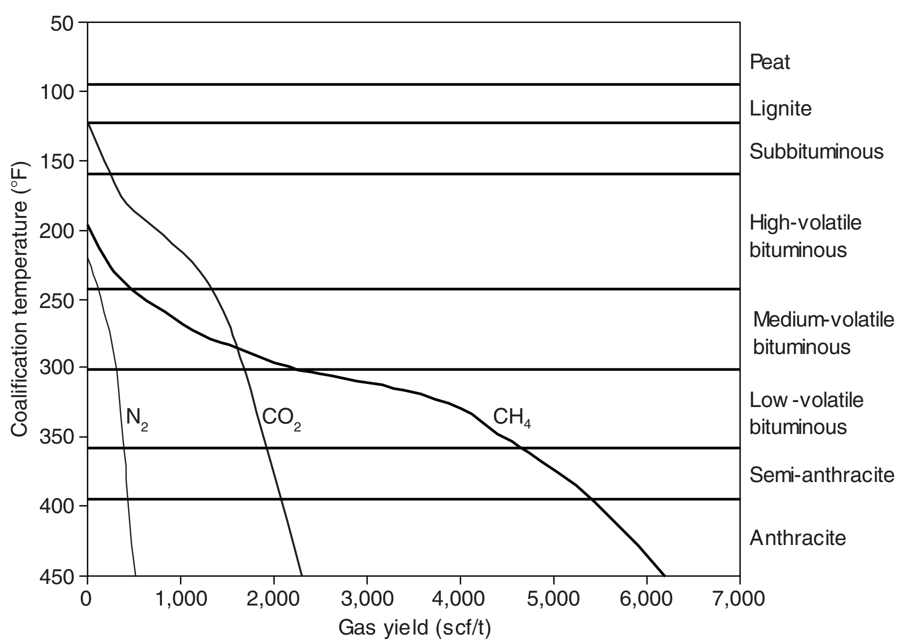

Figure 2 Thermogenic CH_4, CO_2, and N_2 gas generation during coalification (after Hunt 1979, Rice 1993).

Macroporosity, found primarily in orthogonal natural fractures or "cleats" that form in the coal, holds some free CH_4 gas and acts as the main permeability pathways to deliver desorbed gas to a well or mine void. However, most of the CBM is present not as free gas but as a condensed gas monolayer that is physically adsorbed on to the micropore walls through weak Van der Waals forces. As a result, at a given pressure and temperature, coal can hold much more methane than can an equivalent volume of a conventional gas reservoir rock such as sandstone. The methane storage capacity of coal increases as reservoir pressure increases and as temperature decreases.

The methane storage capacity of coal, although relatively large, is not enough to hold all of the methane it generates, particularly in high-volatile bituminous A and higher coal ranks. For example, the gas retained in Central Appalachian Basin coals of high-volatile bituminous A to low-volatile bituminous ranks was estimated to be an order of magnitude less than the gas generated by these coals (Rogers 1994, Hunt and Steele 1991). Liquid hydrocarbons may partially plug micropore structure in high-volatile bituminous coals (Thomas and Damberger 1976, Levine 1993) and thus reduce the surface area available for methane gas storage. The methane generated in excess of the storage capacity of coal is expelled into the coal macropores and fractures and then to the surrounding strata where it could accumulate in conventional natural gas reservoirs. Carbon dioxide and nitrogen generated during coalification are generally retained in coal in substantially lesser quantities than methane. Apparently, the high water solubility of CO_2 and the inert nature and perhaps relatively small molecular diameter of N_2 (3 Å for N_2 compared with 4.1 Å for CH_4) cause a greater proportion of these gases to be expelled from coal than methane as the coal is compacted with increasing burial. Once formed, the methane gas in coal is held in place by reservoir hydrostatic pressure and Van der Waals forces. However, later geologic processes, such as uplift of coal beds and erosion of overlying strata, can result in methane gas undersaturation of coal because of cooling and decreased reservoir pressure. It should be pointed out that the decreased pressure causes significant degassing only at burial depths of less than 2,500 ft (Scott 2002). Temperature decline during uplift and erosion significantly increases the gas sorption capacity of coal and thus better explains the undersaturation with respect to coal gas observed in many basins (Scott 2002). Man-made depressurization, such as mining and withdrawal of groundwater, can also result in methane gas loss and undersaturation.

Past Work on Illinois Coal and CBM Resources

Coal Resources of Illinois

The optimism for production of commercial quantities of CBM in the Illinois Basin arises from its huge coal reserves. Coal-bearing rocks of the Illinois Basin are of Pennsylvanian age and underlie about two-thirds (36,800 square miles) of Illinois and lesser areas of Indiana and Kentucky (fig. 3).

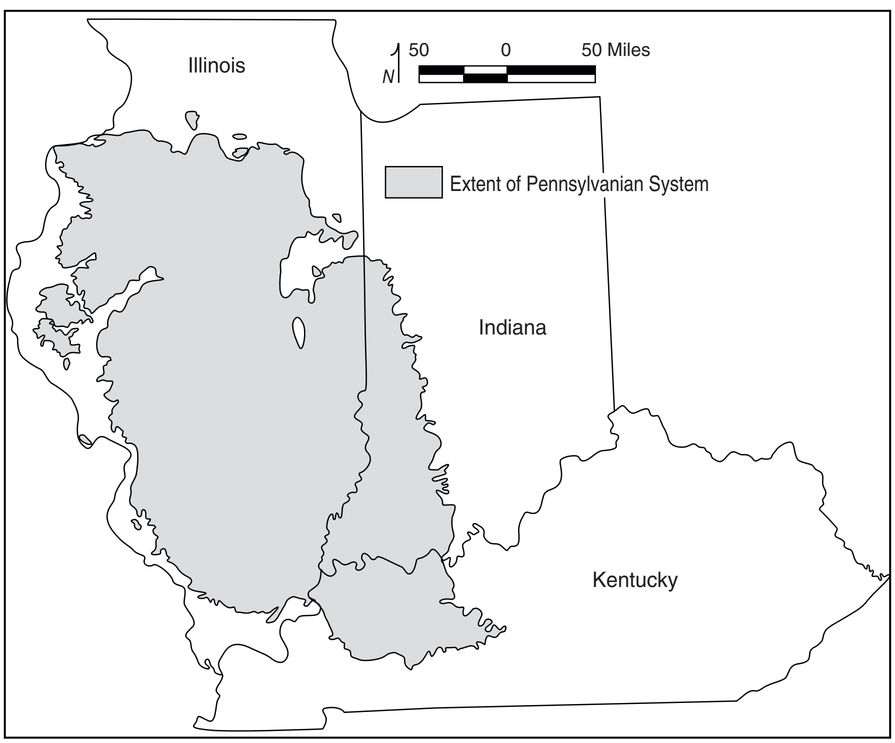

Figure 3 Extent of coal-bearing Pennsylvanian strata in the Illinois Basin.

The Illinois Basin is a north-northwest to south-southeast–trending, broad cratonic basin that evolved over a failed rift complex, primarily during the Paleozoic, and subsequently was closed by post-Pennsylvanian tectonic events (Archer and Kirr 1984, Leighton 1991, Nelson 1991, Kolata and Nelson 1991). Pennsylvanian rocks are the youngest near-surface bedrocks in most of Illinois and generally are overlain by thin Pleistocene glacial deposits. The thickest Pennsylvanian rocks (>2,400 ft thick) occur in the deepest, southeastern part of the basin. The east-west–trending Rough Creek-Shawneetown fault system divides this deepest part of the basin into the broad Fairfield Basin to the north, located in southeastern Illinois, and the deep, narrow Moorman Syncline to the south, located in western Kentucky (Nelson and Bauer 1987). Illinois coal beds are associated with at least 51 Pennsylvanian cyclothems, each of which typically began with the development of a major peat swamp on a broad delta plain followed by transgression with marine black shale deposition, near-shore marine and deltaic clastic sediment deposition, and then the development of a new peat swamp that restarted the cycle (Wanless and Weller 1932, Archer and Kirr 1984, Tedesco 2003).

The area of Illinois underlain by the Pennsylvanian rocks is referred to as the "Illinois coal field" in this publication. The thickest, most extensive minable coal seams in Illinois are found in the Middle Pennsylvanian Carbondale Formation (figs. 4 and 5). Total aggregate coal thickness locally may exceed 40 ft. The Illinois Basin coals are of high-volatile bituminous A, B, and C ranks; the lowest rank coals are located in northwestern Illinois, and coal rank generally increases toward southeastern Illinois. Total coal resources of the Illinois Basin are approximately 284 billion tons, of which 211.4 billion tons are in Illinois. Nationally, Illinois ranks first in total and strippable bituminous coal resources, third in total coal resources, and second in demonstrated total coal reserves (*Keystone Coal Industry Manual* 2003).

More than half of the major coal deposits in Illinois lie at depths of less than 525 ft, and only small portions of the deposits are greater than 1,300 ft deep. Of 75 known seams in the Basin, 27 are thick and extensive enough to have been mapped, but 95% of the resources occur in just 9 seams (Illinois State Geological Survey [ISGS] 2002), namely, the Danville, Jamestown, Herrin, Springfield, Colchester, Seelyville, Dekoven/Davis, Murphysboro, and Rock Island Coals. In Illinois, 85 to 90% of coal production is from Herrin and Springfield Coals. There are many ISGS reports, articles, and maps containing information on the coal resources of Illinois (Treworgy and Bargh 1984; Treworgy et al. 1997, 1999, 2000a, 2000b, 2000c; Korose et al. 2002, 2003; *Keystone Coal Industry Manual* 2003). The information available on the nine important coal seams in the order of increasing stratigraphic age (fig. 6) is summarized here.

Danville (No. 7) Coal The known minable resources of the Danville Coal

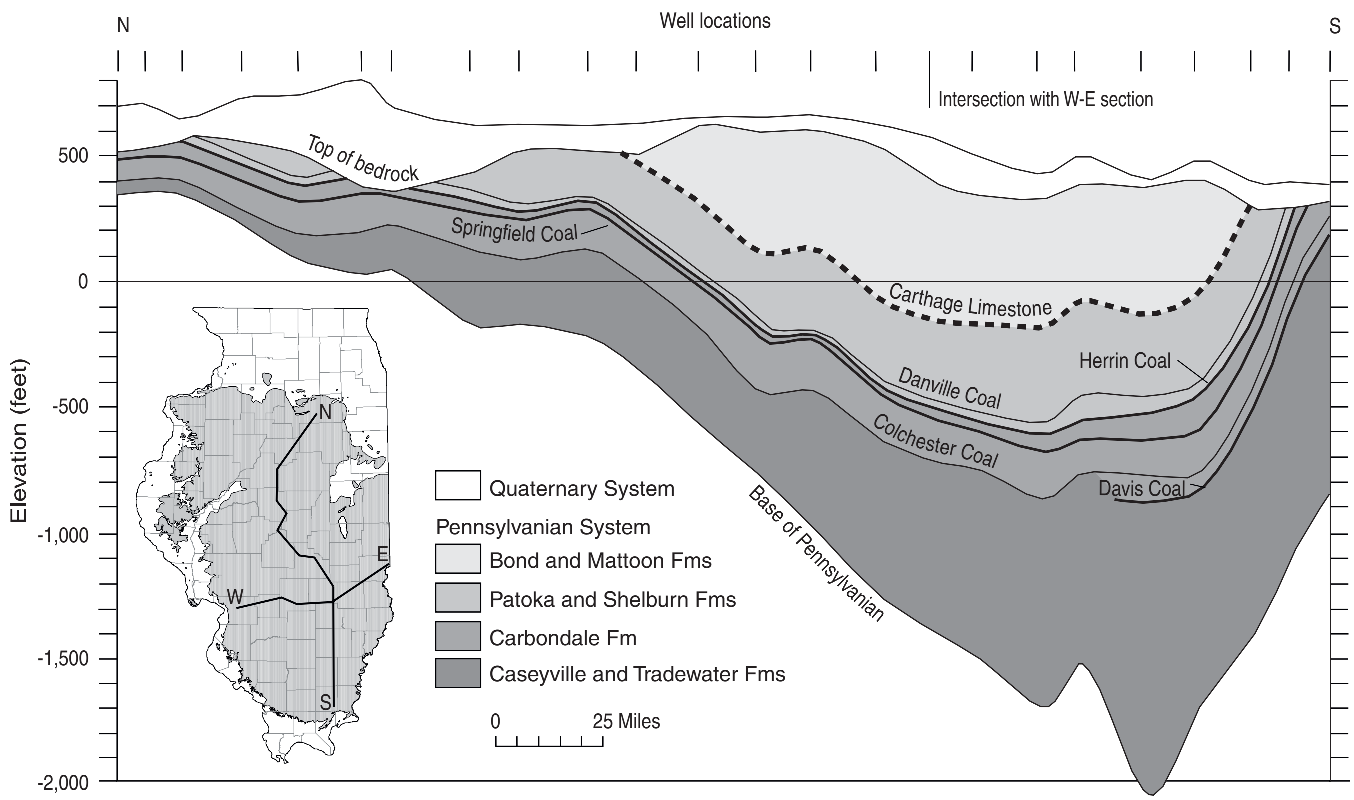

Figure 4 Generalized north-south cross section of Pennsylvanian strata in Illinois.

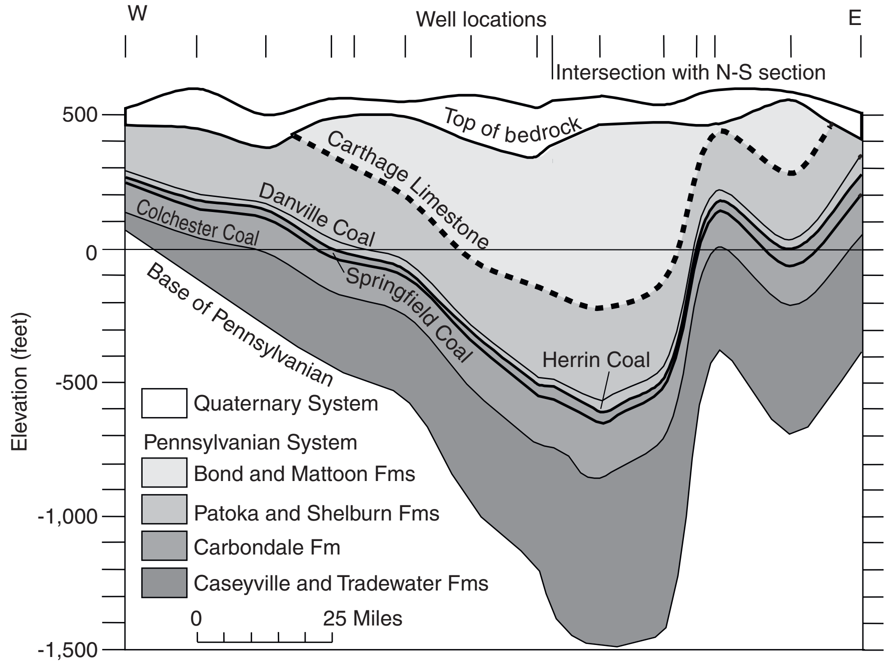

Figure 5 Generalized west-east cross section of Pennsylvanian strata in Illinois. Cross section location shown in figure 4.

can be found in the north-central, east-central, and southernmost areas of the Illinois coal field. This coal has been mined in some areas of the east-central (Vermillion County) and northern (La Salle and Marshall Counties) Illinois coal field. Currently, no Danville Coal is being mined. However, the potential for mining exists in northeastern McLean and adjacent Livingston Counties and in unmined areas of Vermilion County. In mined areas, the Danville Coal generally is 2.5 to 6.0 ft thick. In other areas, thickness usually ranges from a few inches to 3 ft. The Danville Coal is estimated to contain 19.1 billion tons of unmined coal.

Jamestown Coal The Jamestown Coal has never been mined in Illinois, although it can be relatively thick and shallow in some areas. The Jamestown occurs in large areas of the east-central Illinois coal field and has minable thicknesses (3.5 to 5.5 ft) in Clark, Crawford, and Lawrence Counties. The Jamestown Coal is known as the Hymera Coal in Indiana where it has been mined. Some of the mine roof problems encountered in the Indiana mines may extend to Illinois, making the Jamestown seam too costly to mine in the state. The Jamestown Coal is estimated to contain 3.6 billion tons of unmined coal.

Herrin (No. 6) Coal The Herrin Coal contains the most resources of any minable coal seam in Illinois and can be found in most areas of the Illinois coal field. It has been mined most extensively in the west-central, southwestern, and southern areas of the Illinois coal field. There has been some mining of the Herrin Coal also in the northern, east-central, and southeastern portions of the Illinois coal field. Currently, about 60% of the Illinois coal mines produce from the Herrin. The thickness of the Herrin can exceed 9 feet, but it generally is 6 to 8 ft thick in most of the mined areas. Its thickness is irregular, but locally appears to reach 6 ft or more in some unmined areas located in the deeper part of the coal field. The Herrin seam is estimated to contain 78.8 billion tons of unmined coal.

Springfield (No. 5) Coal The Springfield Coal is the second most important minable coal seam in Illinois. Like the Herrin Coal, the Springfield extends throughout most of the Illinois coal field. The Springfield has been mined in many counties in west-central (Sangamon, Logan, Menard counties), central (McLean County), east-central (Edgar County), southeastern (Saline, Gallatin, Hamilton, and Wabash Counties), and southwestern (Perry, Randolph, Jackson, and Williamson Counties) Illinois. Currently, about 30% of the Illinois coal mines are Springfield Coal mines. The Springfield Coal is usually 4.5 to 6.0 ft thick but is 5 to 10 ft thick in a 4- to 10-mile-wide zone extending about 70 miles from Wabash County to Saline County in southeastern Illinois. The Springfield Coal is estimated to contain 62.8 billion tons of unmined coal.

Colchester (No. 2) Coal Although the Colchester Coal is widespread over the entire Illinois coal field, it reaches minable thicknesses only in the western and northern portions. The Colchester can be 42 inches thick in areas to the west of the La Salle Anticline in Bureau, Putnam, and western La Salle Counties. To the east of the La Salle Anticline in Kankakee and Will Counties, as well as further west of the anticline in Henry County, the coal is 30 to 40 inches thick. In the southern areas of the Colchester Coal field, its thickness commonly ranges from 18 to 30 inches. Currently there is only one active Colchester

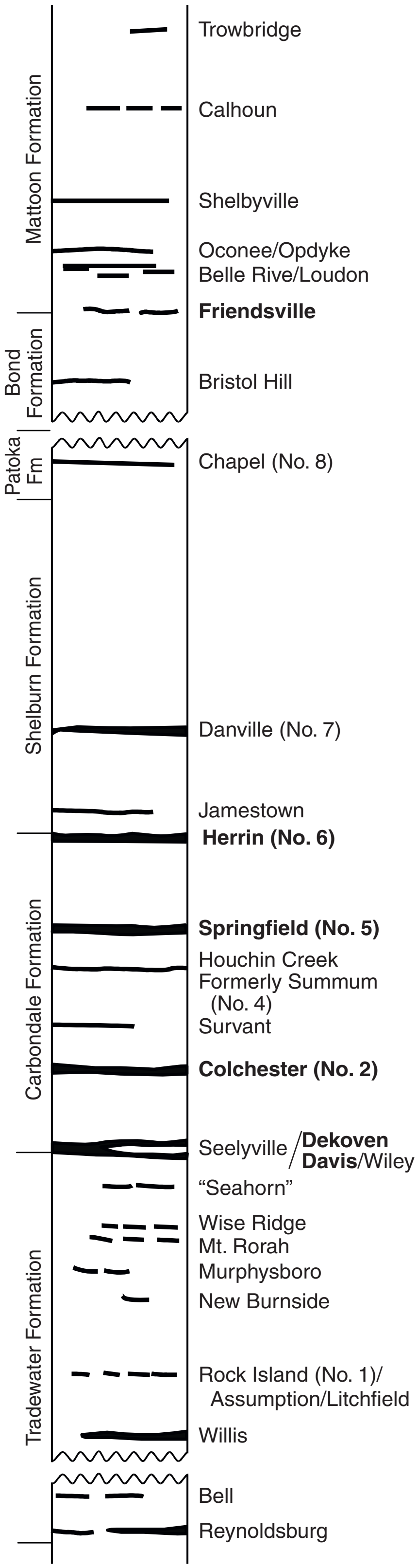

Figure 6 Generalized stratigraphic section showing approximate vertical relationships of coals in Illinois (bold type indicates coals mined in recent years).

mine, a surface mine in McDonough County. However, the seam was mined more extensively in the past in western and northern Illinois. The Colchester seam is estimated to contain 17.4 billion tons of unmined coal.

Dekoven and Davis Coals The Dekoven and Davis Coals are considered to be splits of one seam; the Dekoven is commonly 10 to 25 ft above the Davis. These coals have been mapped in Franklin, Williamson, Saline, Gallatin, White, Hamilton, Wayne, Edwards, and Wabash Counties in the southern Illinois coal field and were surface mined extensively in southern Saline, eastern Williamson, and Gallatin Counties. Thinner Dekoven and Davis Coals are also present west of where they were mapped. There has been only one Dekoven/Davis underground mine, a relatively recent and still active mine located in Gallatin County. In mined areas, the average thicknesses were 3 to 3.5 ft and 3.5 to 4.0 ft for the Dekoven and Davis Coals, respectively. These coals are stratigraphically correlated to the Seelyville Coal further north and east in Illinois and Indiana. The Dekoven and Davis Coals are estimated to contain 5.9 billion tons of unmined coal.

Seelyville Coal The Seelyville Coal occurs in eleven counties (Edgar, Coles, Clark, Cumberland, Jasper, Crawford, Lawrence, Richland, Clay, Effingham, and Shelby) of east-central Illinois. The seam thickness may range from 3.5 to 9 ft. This seam has never been mined in Illinois. The Seelyville Coal is estimated to contain 9.7 billion tons of unmined coal.

Murphysboro Coal The Murphysboro Coal has been mapped in the southwestern quadrant (Jackson, Perry, western Williamson, and possibly Randolph Counties) of the Illinois coal field. Thicknesses range from about 1 to 7 ft. The Murphysboro has been mined in Jackson and Williamson Counties. The Murphysboro Coal is estimated to contain 1 billion tons of unmined coal.

Rock Island (No. 1)/Litchfield/ Assumption Coals The Rock Island Coal was in the past extensively mined in the northwestern areas of the Illinois coal field. The mined coal was commonly 4 to 5 ft thick. The Rock Island Coal is stratigraphically correlated with the Litchfield and Assumption Coals, formerly mined at single locations in Montgomery and Christian Counties, respectively. The combined seams of Rock Island, Litchfield, and Assumption are estimated to contain 1.5 billion tons of unmined coal.

Methane Gas in Illinois Coals

Sample Gas Desorption Data and Gas Emission from Mines In the past, Illinois mines were the sites of many mine gas explosions (Appendix 1, table A1) caused by methane release from coal. According to previously published desorption data (Popp et al. 1979, Archer and Kirr 1984, Demir and Damberger 2000), Illinois coals contain 7.5 to 125 cubic feet of gas per short ton (cf/t) of coal (table 1); these values are a little lower when adjusted to 60°F (standard temperature currently used in calculations) from the 77°F commonly used in past publications. Recent measurements indicate relatively high amounts of methane release from selected active Illinois mines (table 2). Calculations based on similar measurements and coal production data for Illinois mines that were active in the mid-1990s yielded gas contents of over 700 cf/t in some cases (table 3). Such calculations, however, appear to overestimate coal gas content, perhaps because of additional methane flux from unmined coal and other strata into the mine space. At the same time, past desorption tests based on sealed coal samples in airtight canisters are likely to have underestimated the gas content of Illinois Basin coals for the following reasons: (1) the amount of gas lost before sealing the coal sample in a canister to produce desorption data was not accounted for correctly; (2) gas contents were not standardized to clean coal (ash-free basis) because the composition of the coal was not determined; and (3) past sample locations may have been concentrated in areas with low rank, shallow depth, inadequate geological seals, or close proximity to adjacent sandstone beds or to mining activities.

Table 1 Previously published coalbed methane contents of Illinois coals, as determined by desorption tests.[1]

County	Drill hole/company	Coal seam	Depth (ft)	As-received gas content (cf/t)[2]			
				Lost	Desorbed	Residual	Total
Clay	Hagen Oil, TRW-DOE	Briar Hill	1,075	NA[3]	16.0	16.0	32.0
Clay	Hagen Oil, TRW-DOE	Danville	994	NA	28.8	12.8	41.6
Clay	Hagen Oil, TRW-DOE	Herrin	1,035	NA	19.2	12.8	32.0
Clay	Hagen Oil, TRW-DOE	Seelyville	1,352	NA	35.2	12.8	48.0
Clay	Hagen Oil, TRW-DOE	Springfield	1,090	NA	28.8	9.6	38.4
Coles	Charleston, ISGS	Danville	963	1.1	63.4	22.5	87.0
Coles	Charleston, ISGS	Herrin	1,067	1.6	30.0	17.0	48.6
Coles	Charleston, ISGS	Shelbyville	504	0.7	3.8	3.0	7.5
Coles	Charleston, ISGS	Springfield	1,092	1.6	27.1	30.9	59.6
Marion	GeoWest, TRW-DOE	Danville	664	NA	22.4	3.2	25.6
Marion	GeoWest, TRW-DOE	Herrin	698	NA	28.8	6.4	35.2
Marion	GeoWest, TRW-DOE	Briar Hill	727	NA	12.8	9.6	22.4
Marion	GeoWest, TRW-DOE	Springfield	732	NA	25.6	3.2	28.8
Franklin	USSteel	Herrin	600	NA	NA	NA	62.4
Franklin	USSteel	Springfield	669	NA	NA	NA	53.4
Franklin	TRW	Herrin	850	NA	53.0	NA	53.0
Franklin	TRW	Herrin	670	NA	72.0	NA	72.0
Franklin	TRW	Herrin	670	NA	69.0	NA	69.0
Franklin	TRW	Springfield	916	NA	38.4	NA	38.4
Franklin	TRW	Springfield	715	NA	70.4	NA	70.4
Franklin	TRW	Springfield	733	NA	62.0	NA	62.0
Jefferson	USBM	Herrin	733	NA	57.6	3.2	60.8
Jefferson	USBM	Springfield	793	NA	25.6	6.4	32.0
Peoria	Northern IL Gas	Colchester	133	NA	NA	NA	32.6
Peoria	TRW	Colchester	133	NA	19.2	16.0	35.2
Wayne	USBM	Herrin	902	NA	NA	NA	60.8
Wayne	USBM	Herrin	970	NA	NA	NA	108.8
Wayne	USBM	Springfield	1,010	NA	NA	NA	99.2
Wayne	USBM	Springfield	1,070	NA	NA	NA	86.4
Wayne	TRW	Herrin	900	NA	38.4	22.4	60.8
Wayne	TRW	Herrin	969	NA	51.2	57.6	108.8
Wayne	TRW	Springfield	1,010	NA	76.8	41.6	118.4
Wayne	TRW	Springfield	1,066	NA	44.8	41.6	86.4
Wayne	TRW	Seelyville	1,287	NA	41.6	22.4	64.0
Wayne	TRW	Seelyville	1,290	NA	48.0	51.2	99.2
White	TRW	Herrin	781		112.0	12.8	124.8
White	TRW	Springfield	908		76.8	16.0	92.8
Mean							61.0
Standard deviation							29.5

[1]Compiled from Popp et al. (1979) and Archer and Kirr (1984).
[2]The values are assumed to be on as-received basis and at 1 atmosphere and 77°F although the analytical basis was not clearly defined for many of the old data.
[3]Not available.

Exploration and Production Activities Despite the large resources, commercial coal gas production in Illinois consists of only relatively small amounts of CMM. For over 30 years, CMM has been used in the Illinois Basin in such local applications as heating water for wash houses at mines, heating buildings and greenhouses, and running engines that drive electric generators or other equipment. Production of CMM from abandoned underground mines in Illinois has been increasing in recent years. Two relatively large commercial CMM operations are producing from wells located in Franklin, Williamson, and Saline Counties. Measurements taken from some abandoned mines indicated significant gas flow rates (table 4) and the potential for further CMM development in Illinois. Industry participation in developing the CBM resources of Illinois has been slow because of the low gas content values reported in 1970s and 1980s, uncertainty of recoverable reserves, low gas prices, and lack of local infrastructure to deliver the gas to major distribution lines.

Recent advances, however, in exploration and production technologies and

Table 2 Recently measured methane emissions and coal production from selected active Illinois coal mines.[1]

Company	Mine	Period	Number of measurements	Emission values (cf/day) Range	Mean	Standard Dev.	2001 Production (tons/year)
American Coal	Galatia #5	01/03/01–07/15/02	101	7,000–4,268,800	752,266	844,927	6,802,876
Arclar Inc.	Willow Lake	03/05/02–07/22/02	8	84,900–306,500	179,500	94,759	NA
Big Ridge, Inc.	Big Ridge #2	01/05/01–11/08/02	14	191,800–866,000	523,100	180,937	1,658,073
Coal Miners, Inc.	Eagle Valley	08/03/01–04/05/02	12	16,600–89,900	45,125	23,821	1,316,099
Consolidation Coal	Rend Lake	01/25/01–07/25/02	28	20,700–2,287,500	477,161	11,421	1,951,489
Freeman United Coal	Crown II	01/19/01–05/16/02	25	90,600–1,041,200	307,664	245,807	1,421,283
Freeman United Coal	Crown III	01/08/01–07/10/02	19	273,100–785,200	501,105	158,590	2,427,808
Old Ben-Zeigler Coal	Zeigler #11	07/19/02	1	267,300	267,300	NA	2,634,000
RAG Amax Holding	Wabash	01/03/01–07/09/02	56	19,200–1,772,500	444,780	318,711	1,569,495
Turris Coal Co.	Elkhart	01/08/01–07/10/02	18	316,800–1,168,600	650,767	201,794	2,075,250

[1]Summarized from the database of the Office of Mines and Minerals of the Illinois Department of Natural Resources.

Table 3 Previously published data on methane emissions and coal production from active Illinois coal mines.[1]

County	Mine	Data collection period	Coal seam	Coal thickness (ft)	Mine depth (ft)	Methane emissions (10^3 cf/day)	Coal production[2] (10^6 tons/year)	Specific emissions[2,3] (cf/t)
Clinton	Monterey #2	1993–1996	Herrin	7.5	330	350 ± 129	2.2 ± 1.0	63 ± 22
Franklin	Old Ben 24	1993–1996	Herrin	7.0	650	1,250 ± 208	1.4 ± 0.9	446 ± 305
Franklin	Old Ben 25	1993–1996	Herrin	7.0	600	1,200 ± 283	1.6 ± 0.1	280 ± 74
Franklin	Old Ben 26	1993–1996	Herrin	8.5–9.0	650	1,850 ± 238	2.7 ± 0.7	275 ± 121
Jefferson	Orient 6	1993–1996	Herrin	5.5–6.0	800	750 ± 58	1.3 ± 0.1	210 ± 24
Jefferson	Rend Lake	1993–1996	Herrin	7.0–9.0	600	1,700 ± 577	2.7 ± 0.9	243 ± 62
Logan	Elkhart	1993–1996	Springfield	5.6	280	400 ± 82	1.7 ± 0.2	86 ± 23
Macoupin	Crown II	1993–1996	Herrin	8.0	330	600 ± 82	1.6 ± 0.0	134 ± 16
Macoupin	Monterey #1	1993–1996	Herrin	5.8–7.5	300	700 ± 163	2.1 ± 0.3	125 ± 36
Saline	Brushy Creek	1993–1996	Herrin	5.8	250	750 ± 208	0.9 ± 0.4	333 ± 134
Saline	Galatia	1993–1996	Springfield	7.0	700	7,257 ± 1,967	5.1 ± 1.2	528 ± 112
Wabash	Wabash	1993–1996	Springfield	6.9	600	4,475 ± 1,195	3.0 ± 0.4	570 ± 215
White	Pattiki	1993–1996	Herrin	5.6	1,006	1,625 ± 427	1.9 ± 0.1	317 ± 98

[1]Calculated using data from U.S. Environmental Protection Agency (1997).
[2]Mean and standard deviation.
[3]See text for the explanation of these calculated gas contents that are usually greater than the gas contents determined from canister.

the increase in gas prices have stimulated interest not only in recovering more of the CMM but also in producing CBM from unmined coal beds in Illinois. Drilling for CMM and CBM in Illinois started in 1970 and accelerated in the 1990s (fig. 7). All CMM and CBM wells were drilled in the southern half of the Illinois coal field (fig. 8). (It should be pointed out that not all completion reports from wells permitted within the past year or so have reached the ISGS database, and, therefore, such wells were not included in figures 7 and 8). Production tests for CBM in Illinois were mostly through single well tests. Although a few wells were initially tested at 55,000 to 300,000 cubic feet per day in Saline and Williamson Counties, those wells were abandoned for technical and market considerations. An expanding project in Sullivan and Vigo Counties, Indiana, near the Illinois border, is the only project now commercially producing CBM from virgin coal beds in the Illinois Basin. The current CBM activities in Illinois are in initial exploration or drilling/testing stage and are concentrated mostly in Franklin, Hamilton, Gallatin, White, and Jasper Counties.

Gas contents of coals in the Warrior, San Juan, and some other large CBM basins (McFall et al. 1986, Scott 2002) are, on average, considerably greater than the gas contents of Illinois coals. However, the CBM potential of Illinois coals may be better assessed when compared with Powder River Basin coals. The Powder River Basin coals are the target of thousands of CBM wells during the last several years, reflecting the boom in drilling for this

Table 4 Chemical composition and flow rate of gas from abandoned coal mines.[1]

Lab no.	County	Mine or drill hole	Depth (ft)	Gas composition (%) CO_2	O_2	N_2	CH_4	C_2H_6	C_3H_6	Heat value (BTU/cf)	Gas flow rate (10^3 cf/day)	Flow pipe diameter (inch)
3539	Christian	Joe Simkins #1		16.3	1.1	63.1	19.0	0.45	0.09	202		
2213	Clinton	Breese-Trenton	435	11.8	0.4	27.1	60.3	0.20	0.10	620	1,000	2.00
3540	Clinton	Pessina #1		10.2	0.3	20.7	68.8	0.00	0.00	696		
2372	Franklin	Zeigler	380	5.9	0.6	28.8	64.7	trace	0.00	655	69	1.25
3742	Franklin	Peabody #1	535	8.2	0.67	13.8	77.3	0.20	trace	785	180	2.00
3694	Gallatin	B & W Coal		0.1	20.7	79.2	0.0	0.00	0.00	0		
3887	Montgomery	G. Stieren, Crown #1	362	5.5	0.0	24.4	69.8	0.20	0.00	711	381	1.25
3689	Perry	F. Hepp, Bernard Mine	105	19.0	0.8	56.8	23.4	0.00	0.00	236	5,860	8.00
3817	Randolph	Moffat Coal #2		3.3	11.6	85.1	0.0	0.00	0.00	0		
2371	St. Clair	Peabody Coal, test hole	126	0.3	trace	10.5	89.2	0.00	0.00	903	20	0.75
1488	Saline	Charter Oil #1A		0.0	0.6	12.8	75.9	9.50	0.00	960		
2803	Saline	A. Farris, Dering Mine	460	4.0	0.5	5.2	90.3	0.00	0.00	914	76	1.25
3578	Saline	A. Farris, Dering Mine		5.5	0.1	3.4	90.9	0.00	0.00	920	52	1.25
1408	Saline	Wasson Mine shaft		6.2	0.6	40.7	51.0	1.50	0.00	543	14	0.75
3923	Saline	M.L. Devillez #3		3.3	4.1	50.8	41.8	0.01	0.00	423	115	1.25
951	Saline	W. Duncan, Cook-Spear #1	439	5.7	0.3	7.3	85.7	0.00	0.00	870	34,000[2]	12.70
1507	Saline	Adams Unit #1 (Sahara #10)		6.2	0.2	2.2	90.2	0.00	0.00	917	500	1.25
3215	Saline	Jade Oil, Dering Mine		6.2	1.5	8.9	83.4	trace	0.00	844	31	1.00
1924	Saline	Sahara #10 Mine	445	8.7	3.5	64.8	23.0	0.00	0.00	233	864	12.70
3830	Saline	Dan January		3.1	0.7	9.8	86.3	0.02	0.00	874		
3750	Saline	J. Wilson, Sahara (O'Gara #8)	405	6.1	0.2	3.1	90.6	0.00	0.00	917	4,000	3.00
1518	Saline	Frank Genet Mine		8.6	0.8	0.0	90.1	0.00	0.00	913		
1909	Saline	Sahara #1 Mine		7.0	3.7	72.7	16.6	0.00	0.00	168		
3091	Vermilion	Bunsenville Mine		6.5	14.4	79.1	0.0	0.00	0.00	0		

[1]From Meents (1981) and unpublished ISGS database.
[2]Anomalous value that could be an analytical error.

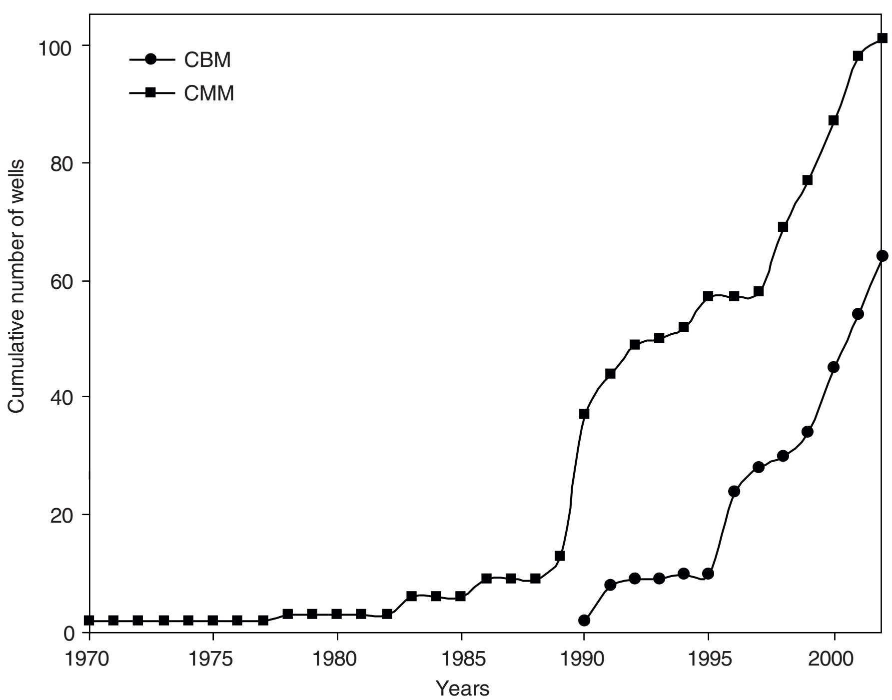

Figure 7 Cumulative number of coalbed methane and coal mine methane wells drilled in Illinois.

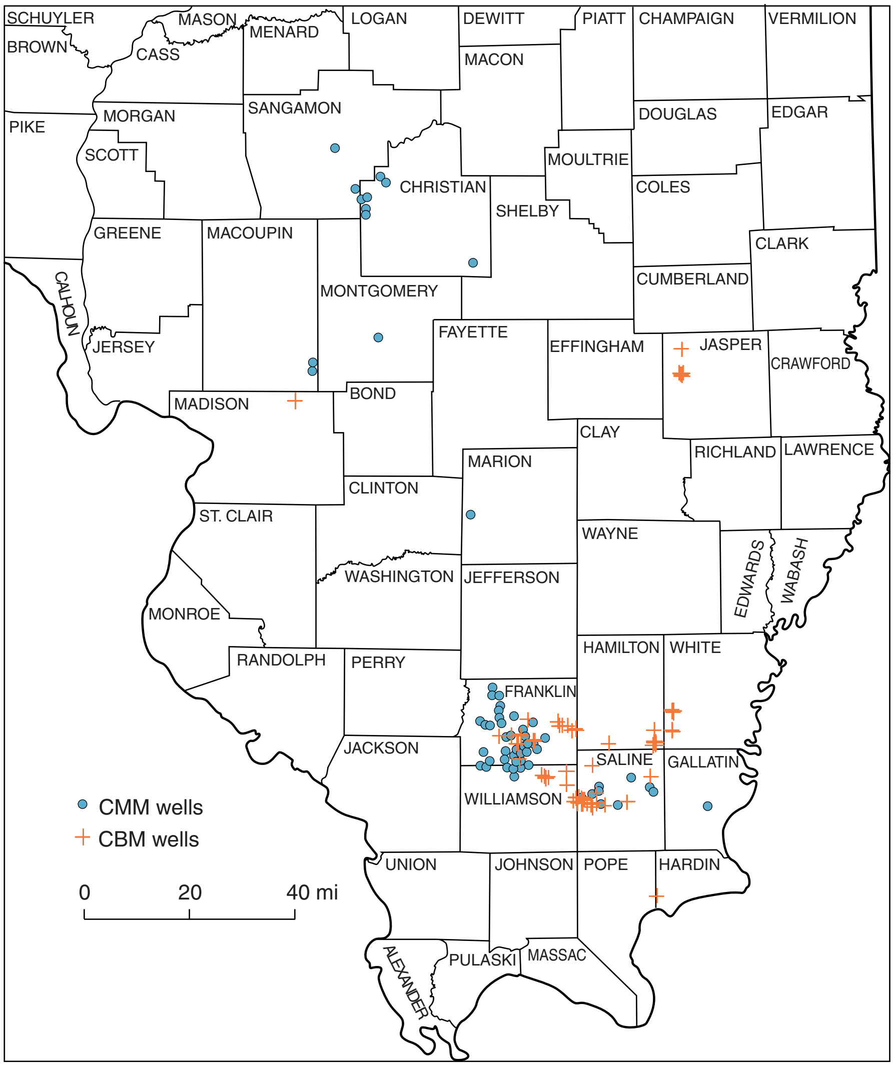

Figure 8 Locations of coalbed methane and coal mine methane wells drilled in Illinois.

unconventional gas resource. The gas contents of Powder River Basin coals generally are below 20 cf/t (Scott 2002), which is a value several times smaller than even the underestimated gas contents of Illinois Basin coals. Generally dry conditions in Illinois underground mines suggest that CBM operations may require less water production and disposal in Illinois than in the Powder River Basin. Although Illinois coal seams are much thinner than the Powder River Basin coals, the combined thickness of multiple Illinois seams can exceed 20 ft in many areas. There is also a lack of data on late-stage microbial methane generation in shallow areas of the Illinois coal field; microbial methane generation is an important process in the shallow Powder River Basin coals. Coal permeability is one of the important parameters for CBM extraction. Anecdotal information suggests that the Illinois coals are considerably less permeable than the Powder River Basin coals. Therefore, addressing the permeability issue, among other things, is important for the development of CBM production in the Illinois Basin.

Project Objectives

Commercial extraction of the CBM locked in Illinois' vast coal resources can sustain economic activity in areas of the state where thick coal seams are present. Although Illinois coal production has decreased in recent years, its potential remains substantial given the continuing growth in U.S. demand for electricity generation and the ongoing improvement and dissemination of clean coal technologies. Meanwhile, Illinois coal companies must remain viable, and CBM can be part of that strategy. Commercial CBM production in Illinois can support the long-term economic viability of coal resources by generating gas royalty income for mineral owners and production profits for resource developers in Illinois. Furthermore, coal seams can be mined more economically and safely after methane extraction, thereby reducing mining cost and ultimately encouraging increased coal production in the state. Illinois is first in the nation in terms of per capita natural gas consumption by residential customers (Finley 2001). Illinois also contains major pipelines, is a market center for natural gas in the north-central region of the United States, and has a well-developed local gas distribution system. Major gas pipelines enter Illinois from the south, bringing natural gas from the Gulf Coast and Midcontinent regions to the Henry Hub in Joliet, Illinois. Coalbed methane shows strong resource potential, especially in southern Illinois where investments in wells, gathering lines, and gas compression infrastructure could readily add CBM to these major distribution systems.

The ISGS initiated this project, supported by Illinois Department of Commerce and Economic Opportunity (IDCEO) and several industrial partners, to produce new data relevant to CBM development in Illinois. These were the project objectives:

1. To generate new, improved gas desorption data that supplement and adjust perceptions of old data for a better understanding of the areal and vertical extent of the CBM content of Illinois coals.
2. To determine the composition and origin of coal gas in Illinois and the composition of water contained in coal from selected areas of the Illinois coal field.

3. To determine the chemical and petrographic characteristics of the newly sampled coals.
4. To identify the areas of the Illinois coal field with high potential for CBM development.
5. To transfer project findings to industry and make them available to the public in order to facilitate commercial production of CBM in Illinois.

Methods

Drilling, Coring, and Logging

Five wells were drilled and continuously cored, using wireline retrieval, from the top of the bedrock surface to total depths of about 500 ft to about 1,220 ft. The wells were drilled between July 2001 and January 2002 to identify coal seams and sample coals for their gas content and composition. The well locations, shown below in chronological drilling order, were selected to represent the different depths and geographical areas of the Illinois coal field:

Well 1, Richland County,
Sec. 27, T4N, R9E;

Well 2, Franklin County,
Sec. 25, T6S, R4E;

Well 3, Clark County,
Sec. 8, T9N, R12W;

Well 4, Macoupin County,
Sec. 7, T9N, R6W;

Well 5, Bureau County,
Sec. 33, T17N, R11E.

A commercial rotary drilling rig was hired to carry out the drilling. Well bores were drilled with fresh water, except for Well 1, which used bentonite drilling mud for the deeper half of the hole. Cores were retrieved by wireline to minimize the amount of time and, thus, gas lost during the transport of coal cores to the surface. The core diameter was 3.25 inches. Cores were taken in 10-ft increments. Core recovery was almost always 100%. After core was removed from the core barrel, the rock was described, sampled, and boxed. The depth at which the core was found was recorded.

Wireline logs of well bores were obtained to supplement the core data for generating information on reservoir characteristics of coal beds, such as the thickness, stratigraphic position, and nature of roof rock. For each well, gamma-ray, spontaneous potential, and 8-inch, 16-inch, 32-inch, and 64-inch resistivity logs were generated. Gamma-ray logs were obtained through drill pipe and open borehole. Then, spontaneous potential and resistivity logs were run in the fluid-filled open borehole after the drill pipe was removed, depending upon hole stability conditions. A collapsed borehole wall in some early wells blocked the logging tool. To obtain at least the basic gamma ray log, the tool was run in later wells through drill pipe.

Gas Content Measurements

Sealing Samples in Canisters For gas and other analyses, one to three core samples (when possible) were taken from each coal seam or black, high gamma-ray shale bed from the drilled wells. Once at the surface, coal cores were quickly removed from the core barrel, cut to 1-ft lengths, and sealed in airtight desorption canisters. To calculate accurately the amount of gas lost from the cores prior to sealing, the times of coring of coal, lifting the core off the borehole bottom, arrival at the surface, and sealing of the cores in canisters were carefully recorded. Vehicle air conditioning or heaters attached to the canisters were employed during extremely hot or cold days to keep the temperature of the sealed coal cores as close as possible to their formation temperature. Formation temperature was calculated from mean surface temperature, coal depth, and published geothermal gradients for each drilling location.

Desorbed and Lost Gas Determinations To determine the desorbed gas content of coal and shale samples, we measured, at timed intervals, the volumes of gas released from the samples and accumulated in the free space of the canisters. The released gas was bled into a volumetric displacement apparatus, called a manometer, by opening a valve attached to the canister. The principal component of the manometer is a burette filled with sodium sulfate solution of 50% saturation. Selection of burette size and resolution varied with the anticipated volume of desorbed gas. Time, canister pressure and temperature, barometric pressure, and ambient temperature were recorded each time released gas volume was measured. The frequency of the desorbed gas measurements depended on desorption rate, equipment, and technique used. Generally, measurements were made every 10 minutes during the first hour, every 15 minutes between hour 1 and 2, every 30 minutes between hour 2 and 3, every hour between hour 3 and 6, every 2 hours between hour 6 and 10, and then less frequently after that depending on the rate of desorbed gas accumulation in the canisters. The samples were generally kept in the field under stable conditions for 4 to 12 hours before being transported to the hotel room or laboratory. Gas desorption from coals or shales became negligible after 2.5 to 4.0 months. Then, the cores were removed from the canisters, and their weight and bulk volume were measured. All relevant desorption, coal weight and volume, and canister volume data were input to a software application (Desorption Analysis software by Gas Research Institute 1995) to compute desorbed and lost gas contents of each core of coal or shale.

Residual Gas Determinations Coal and shale cores were removed from the canisters at the end of the desorption measurements, and a split was ground to release and capture the residual gas. The cores were cut perpendicular to the bedding surface to obtain a representative split for grinding. Typically a 100-g split was ground to <200-mesh size in a sealed SPEX mill. The gas released from the ground coal was vented into a manometer to determine its volume. Then, the manometer temperature and barometric pressure were determined to correct the gas volume to standard conditions (1 atmosphere, 60°F).

Gas Sampling and Analysis

Desorbed gas from each canister was sampled generally three times within the first 10 days of desorption measurements. The base of a hypodermic syringe was connected to the gas desorption line through a control valve. To sample the gas released into the line and then to the manometer, the needle of the syringe was plunged into the rubber cap of a prevacuumed serum tube, and then the valve was opened to vent the gas into the tube. The rubber cap seals itself after the needle is pulled out; however, as a precaution, a little high-vacuum silicon grease was applied to the cap to prevent gas leakage during storage.

Residual gas released from the SPEX mill into a manometer was sampled in a manner similar to the sampling of the desorbed gas from the canisters. All gas samples were analyzed for chemical composition, and selected samples were analyzed for the carbon and hydrogen isotopic composition of the CH_4 component of the gas. Chemical composition was determined by gas chromatography and isotopic composition by gas chromatography-mass spectrometry.

Coal Chemical and Petrographic Analyses

The coal samples from the desorption canisters were chemically and petrographically analyzed. The chemical analyses were done to determine proximate composition (moisture, ash, volatile matter, fixed carbon, and total sulfur) according to established ASTM (1995) procedures.

The petrographic work included the determination of maceral composition and vitrinite reflectance of polished composite samples of coal. Maceral analysis was performed using a Leitz MPV2 microscope. Observations were made in white and fluorescent light. Generally maceral composition was calculated on 500 points per sample. Volume percent of the main maceral groups (vitrinite, liptinite, and inertinite) and of individual macerals in each group and mineral matter were determined. Vitrinite reflectance of 50 random points per sample was determined using a Zeiss Photoscope microscope. A glass standard of 1.009% reflectance was used for calibration. Average random vitrinite reflectance and standard deviation were calculated, and a histogram of reflectance was constructed for each sample.

Methane Adsorption Isotherms of Coals

A coal sample was crushed to <60 mesh. A 150- to 200-g split of the crushed sample was equilibrated with moisture to restore its original in situ moisture (ASTM 1995) because moisture significantly affects gas adsorption by coal. The moisture-equilibrated coal was exposed to methane gas at constant reservoir temperature and at a series of pressures calculated to yield the desired distribution curve of equilibrium adsorption pressures. Each adsorption step consisted of charging a reference cell with methane to a calculated starting pressure. After allowing for stabilization of the pressure and temperature, pressure was released from the reference vessel into the sample chamber. The resulting pressure was monitored until equilibrium was achieved. Data were analyzed using Boyle's law. Gas compressibility and changes in dead volume due to gas adsorbing on the coal were considered in the data reduction process (Gas Research Institute 1995). A final isotherm curve was then prepared that showed the equilibrium gas adsorption capability at various pressures.

CBM Development Maps

Coal parameters relevant to CBM were compiled to produce digital geological maps. A methodology similar to that used by Treworgy et al. (1997) was followed to generate the digital maps of areal distribution of coal thickness, depth, elevation, rank, and cleat orientation and of structural features and mined-out areas. All maps were constructed in ArcGIS using data layers from the ISGS GIS database (county boundaries and tectonic features) and the Coal Section GIS database (coal thickness, depth, elevation, rank, and cleats). Data layers such as coal thickness, depth, elevation, tectonic features, and rank come from previous studies; the cumulative coal thickness layer was constructed for this study.

The cumulative coal thickness map was constructed by adding grids of 0.5-ft contours from the thickness maps of 27 individual coal seams in a GIS. Each seam thickness map (coverage) considered mined areas, unmapped areas, unminable areas between mines, channels, and coal less than 18 inches thick (a potential minimum thickness for CBM well completion) as zero thickness. All maps were edited to conceal confidential data. The coals included in the cumulative coal thickness map were, in stratigraphic order, Trowbridge, Shelbyville, Opdyke, Loudon, Belle Rive, Friendsville, Bristol Hill, Danville, Jamestown, Herrin, Springfield, Houchin Creek, Survant, Colchester, Seelyville, Dekoven, Wiley, Davis, "Seahorne", Wise Ridge, Mt. Rorah, Murphysboro, Rock Island, Litchfield, Assumption, and Willis.

Chemical Analysis of Produced Water

Major elements and total dissolved solids (TDS) contents of produced water from a CBM test well were determined using inductively coupled plasma spectroscopy and ion chromatography methods. The test well was drilled about 4 miles west of our Franklin County well by one of our industrial collaborators.

Results and Discussion

Drilling, Coring, and Logging

Continuous core drilling provided a unique view of the Upper and Middle Pennsylvanian rocks of Illinois. Three to eight coal seams were sampled in each location (figs. 9, 10, 11, 12, 13); several black, organic-rich shales were also sampled in some locations. The coal-bearing stratigraphic sections contain various amounts of shale, sandstone, and limestone. Shales of varying organic matter content are particularly common. The thin, high-gamma-ray shales have methane gas potential, although less than that of coal seams of comparable thickness. Lithological descriptions with corresponding geophysical logs (figs. 9, 10, 11, 12, 13) can be used as references to identify Pennsylvanian coals and black shales in other wells that have only geophysical logs. Illinois coals typically yield low gamma-ray and high resistivity log signals; black shales yield opposite signals (high gamma-ray, low resistivity). Although continuous coring of wells, as done in this project, is not a common practice in the industry, this method has produced an unprecedented collection of Illinois Pennsylvanian sediments. All of the cores from this project are stored at the ISGS Geological Samples Library and are available to other scientists for future geological studies.

Gas Contents of Coals and Shales

Fifty-nine coal samples and five shale samples were analyzed for gas content, which represents the most extensive database of gas contents generated on Illinois coals. Sample descriptions and gas content measurements are given in table 5 and Appendix 2, respectively. Excluding the samples from the northernmost well (Bureau County), the gas content of the coal samples ranged from 36.5 to 173.2 standard cubic feet (scf/t) on a dry, mineral matter free (dmmf) basis (table 6; fig. 14); mean and standard deviation were 85 scf/t ± 31. Gas contents in shales ranged from 9.6 to 40.7 scf/t on an as-received basis and from 52.1 to 145.3 scf/t on a dmmf basis. Correlation is good between gas contents of coal samples on both as-received and dmmf bases (fig. 15). Thus, dmmf gas contents can be estimated from as-received gas contents when mineral matter and moisture analyses of coal are not available.

Coal samples from the Bureau County well had gas contents of only 4.6 to 5.8 scf/t. These values were unreasonably low even for this particular area of shallow depths and low coal ranks. The adsorption isotherm of a Bureau County coal indicated that the coal is capable of holding over 80 scf/t methane at the current reservoir temperature and pressure. The Bureau County well was drilled on the western flank of the La Salle Anticline and about a mile from the Cherry and Ladd mines that were closed about 80 years ago and had workings in all three of the coal seams that were sampled. The coals may have lost gas to the atmosphere because of gas migration to mine tunnels, induced by lowered hydrostatic pressure from pumping water out of the mines. Another possibility would be the loss of gas due to the meteoric water flushing of gas to other areas or to the atmosphere over geologic time. The hydrogeological evolution of the area must be delineated before actual causes can be determined. Because of these anomalously low values, the Bureau County data on gas content cannot be compared with the gas content data from the other wells of this project and are not considered representative. The gas content values (table 6), excluding the questionable Bureau County well, were higher than expected at relatively shallow depths compared with data for some other basins (Scott 2002).

The gas contents obtained from all canister desorption tests should be considered as minimum gas contents. It is possible that some gas may have leaked along fractures created by the mechanical stress of drilling and flushing of the core by constant drilling fluid circulation during cutting of the cores. Such gas loss is not accounted for by the current measurement techniques. Therefore, actual in situ gas contents of coals in the ground are likely to be somewhat greater than those obtained from canister tests. The maximum gas a coal might hold can be determined from adsorption isotherms; the true gas content probably lies between the desorption and adsorption values. However, canister tests are still essential for obtaining a standardized gas content value, helping to determine the regional and local gas content variations, and calculating minimum reserves.

Coal Gas Variations in Individual Wells

Among samples taken from the same coal seam, gas contents vary (fig.14), which might reflect minor compositional variations of macerals and minerals in the coal (table 7, Appendix 2) as well as normal analytical variation. Scott (2002) also documented gas content variations vertically within thick coal beds, laterally within individual coal beds, and vertically among coal beds within a single well. Scott attributed such variations to geological heterogeneities, the types of samples taken, and/or the analytical laboratory. Thus, it is important that at least two samples, and preferably three, if possible, be taken from each seam to obtain an average gas content value.

In a single well, gas storage capacity of similarly ranked coals should increase with depth because of increasing hydrostatic (reservoir) pressure; this relationship results in a positive correlation between gas content and depth if enough gas is available for adsorption by coal. If deeper coals attained higher ranks, the positive correlation between the gas content and depth would be enhanced. The trend of increasing gas content with increasing depth generally holds for the four wells with substantial gas contents, except for those Franklin County samples taken from depths of greater than 900 ft (fig. 16). There is a very weak tendency for gas content to increase as vitrinite reflectance (coal rank) increases when all coal seams in all four wells are considered together (fig. 17). There is no relationship between gas content and vitrinite reflectance in each individual well, although vitrinite reflectance in each well can be somewhat variable (fig. 17). Unexpectedly lower gas contents for coals deeper than 900 ft in the Franklin County well and in the Richland County well (fig. 16) suggest that the deeper coals at these locations have been subjected to different geological conditions that are not understood at this point. Details of local hydrogeological, structural, and stratigraphic conditions must be understood to explain the relatively

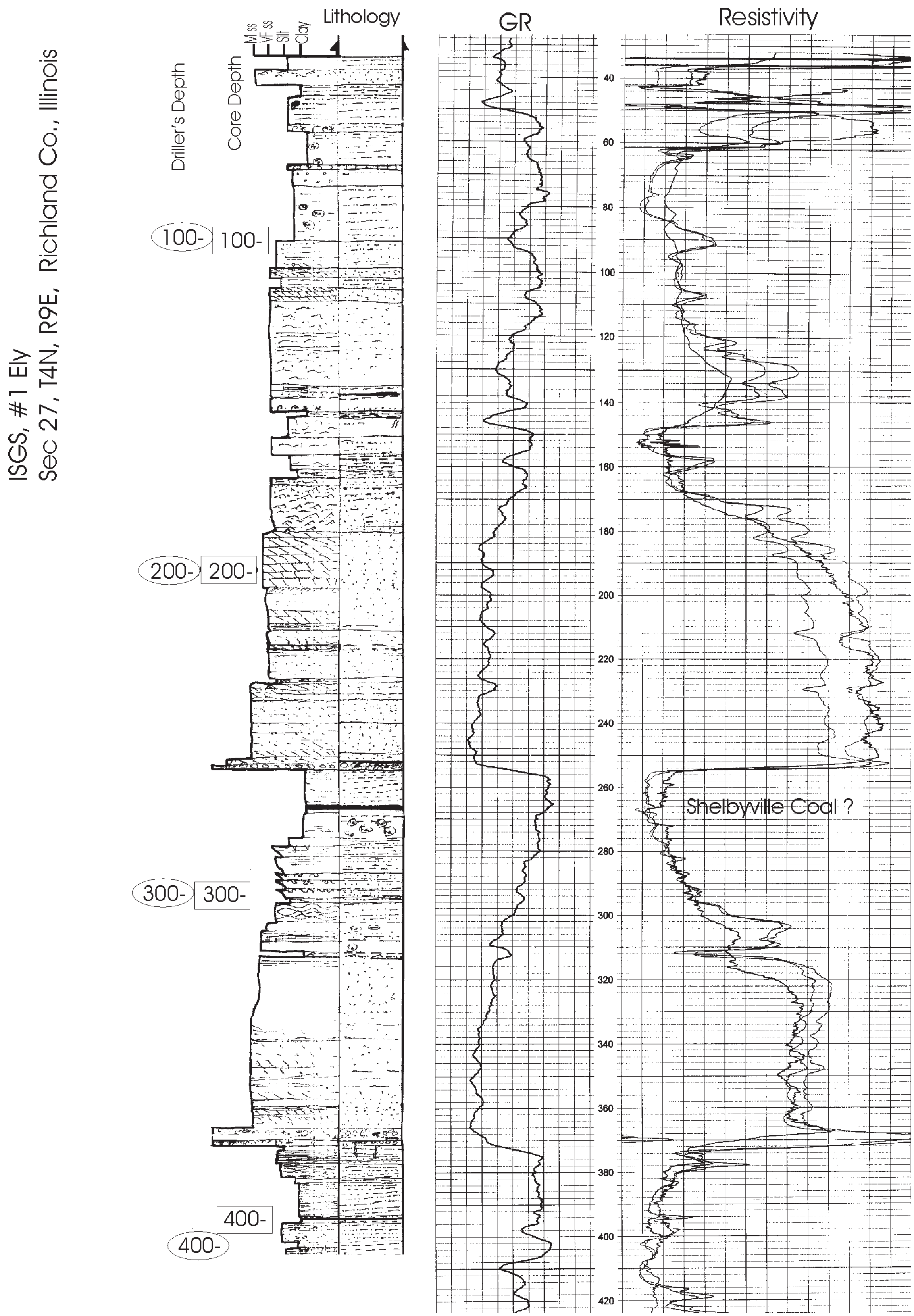

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Figure 9 Lithology and geophysical logs of the Richland County well: (a) 30 to 400 ft, (b) 400 to ~850 ft, and (c) ~850 to 1,216 ft (T.D.).

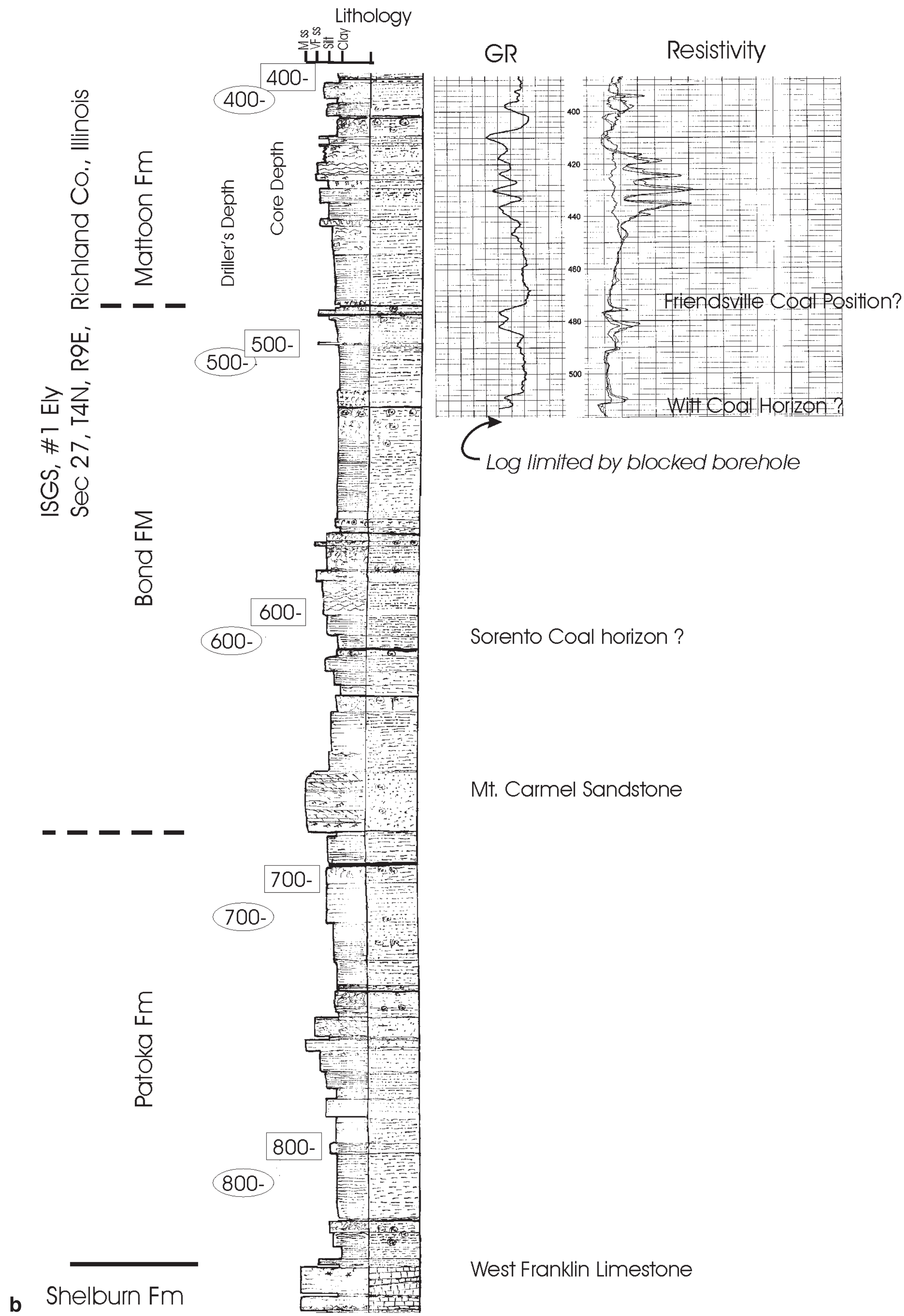


Figure 9 (continued) Lithology and geophysical logs of the Richland County well: (a) 30 to 400 ft, (b) 400 to ~850 ft, and (c) ~850 to 1,216 ft (T.D.).

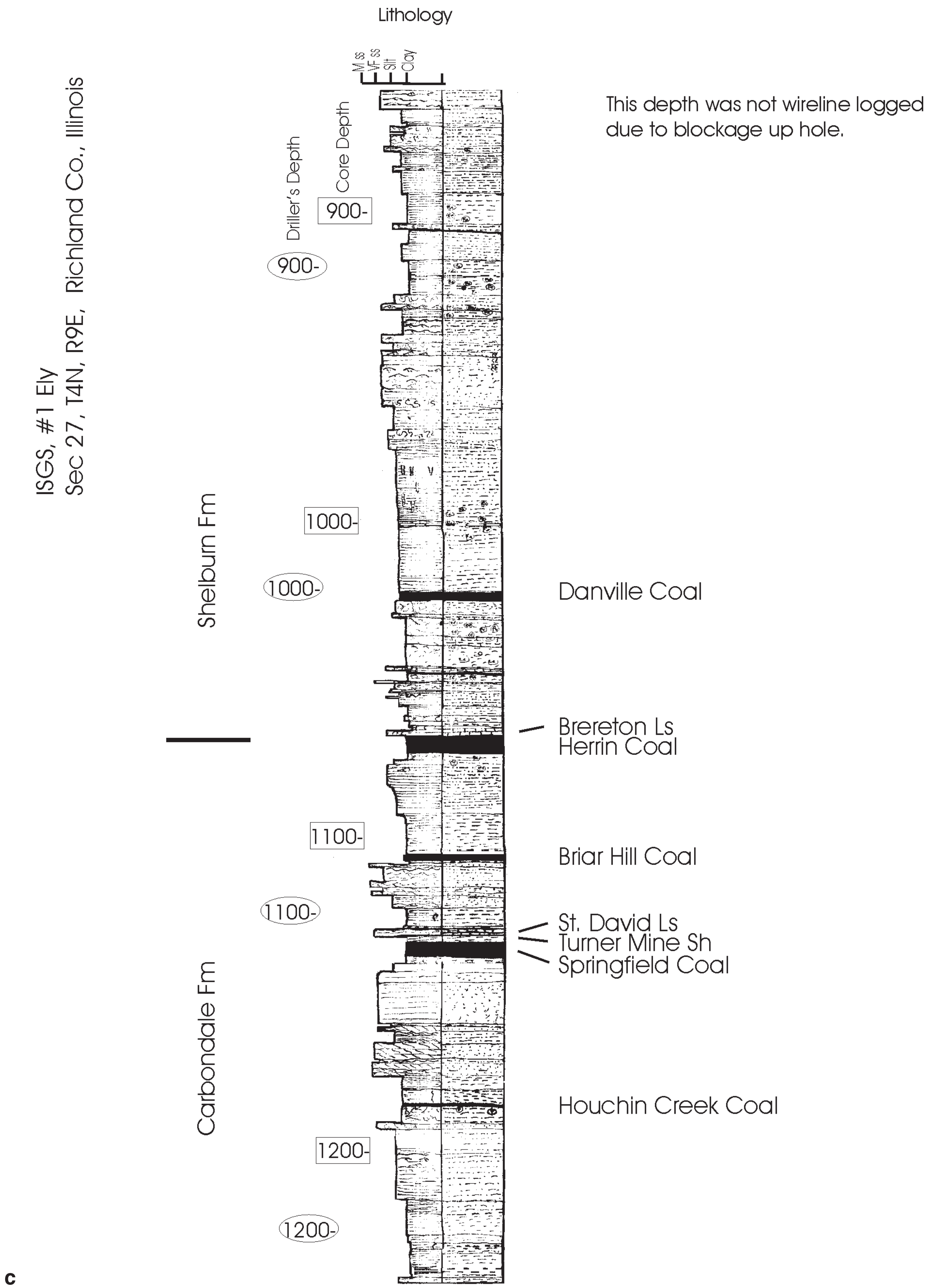


Figure 9 (continued)

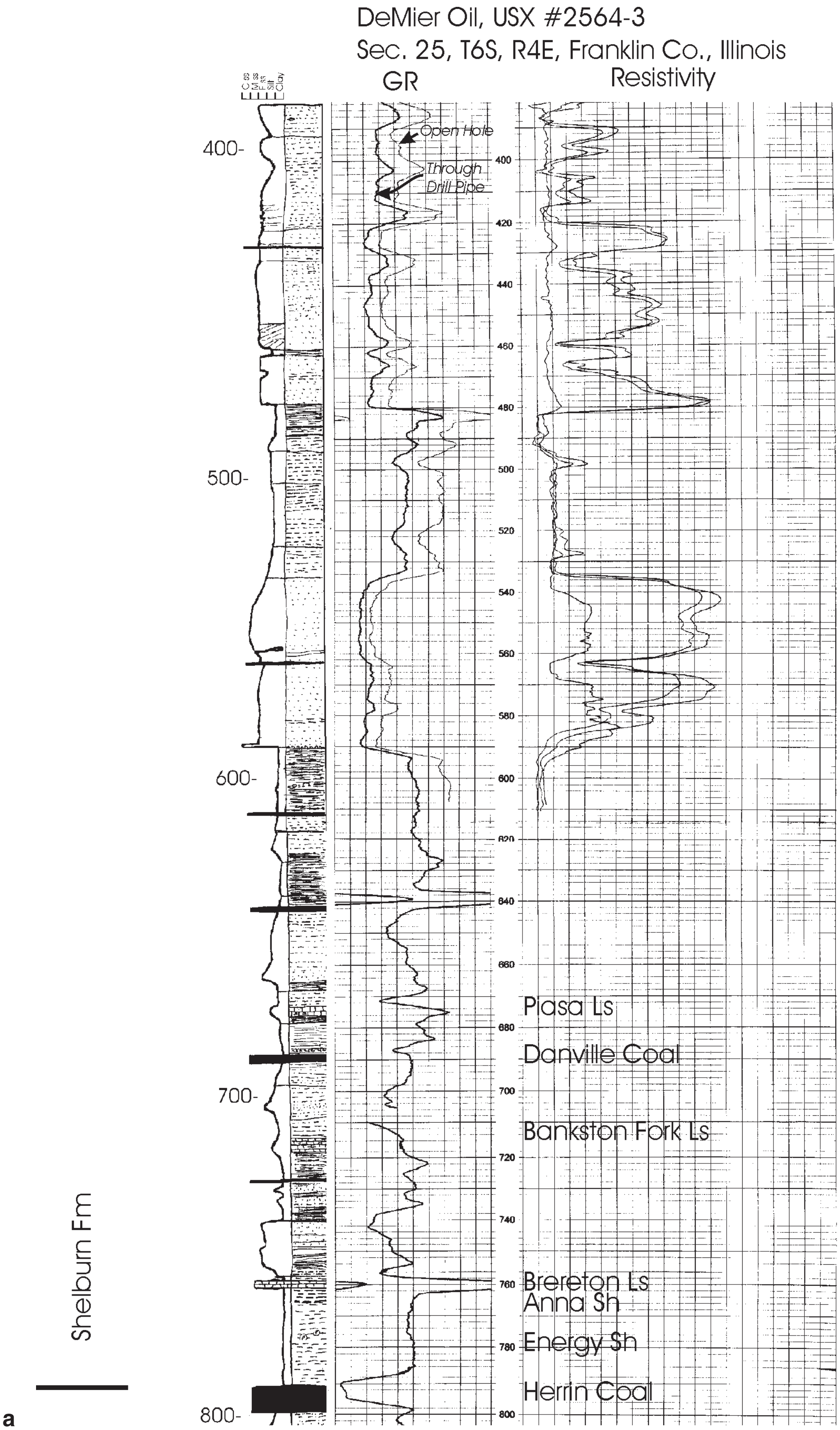


Figure 10 Lithology and geophysical logs of the Franklin County well: (a) 400 to 800 ft, and (b) 800 to 1,194 ft (T.D).

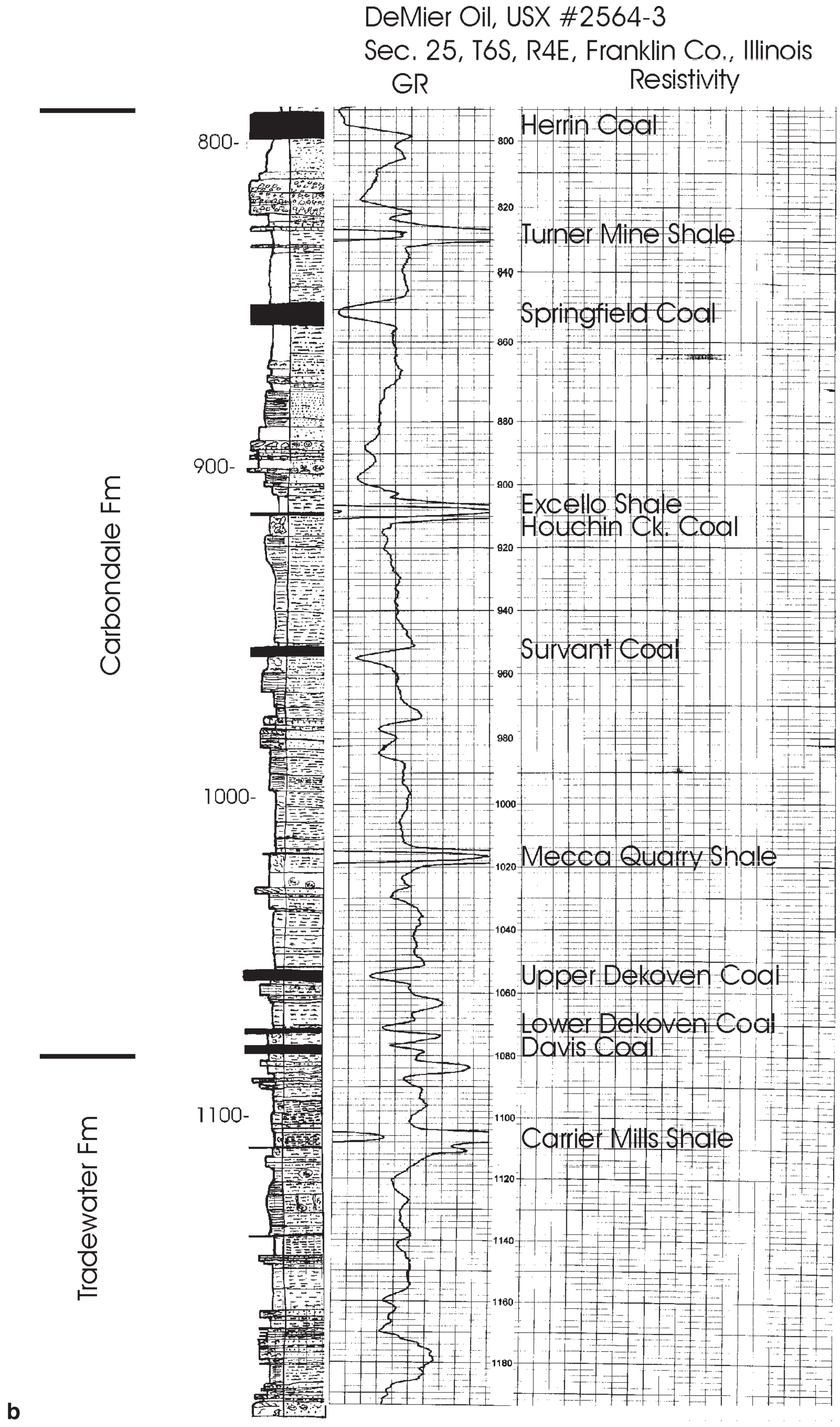


Figure 10 (continued)

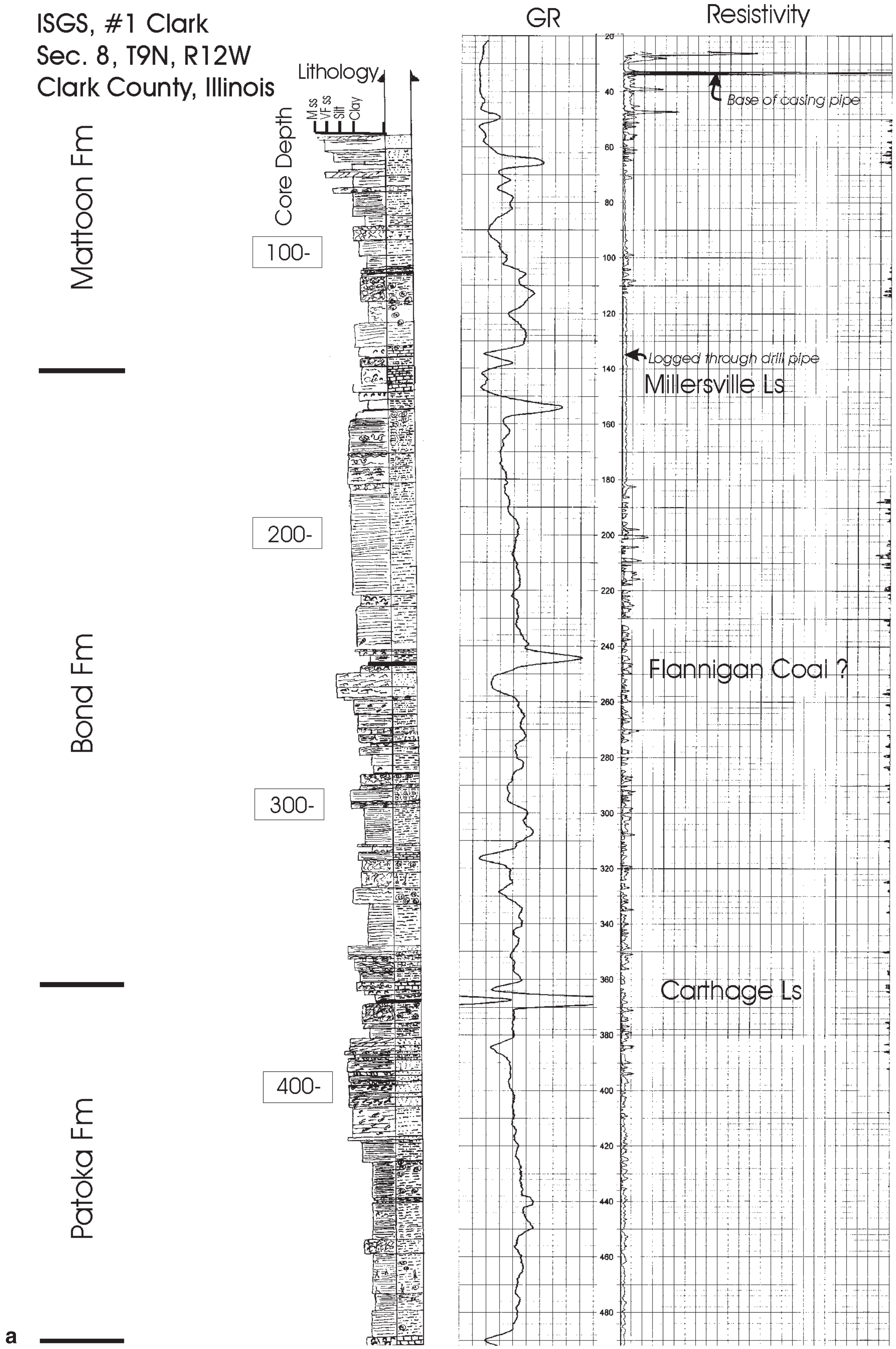


Figure 11 Lithology and geophysical logs of the Clark County well: (a) 20 to 490 ft, and (b) 490 to 837 ft (T.D.).

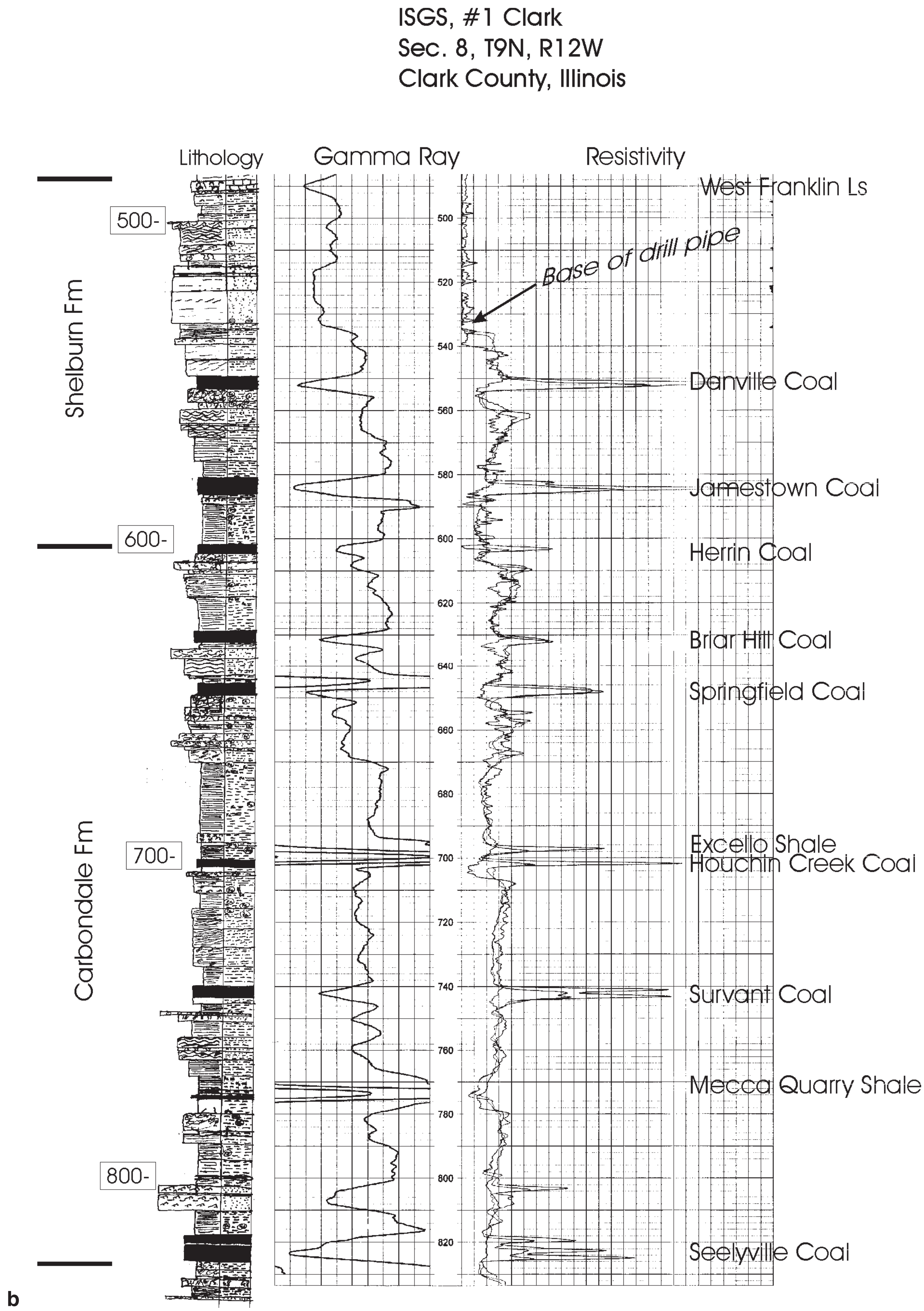


Figure 11 (continued)

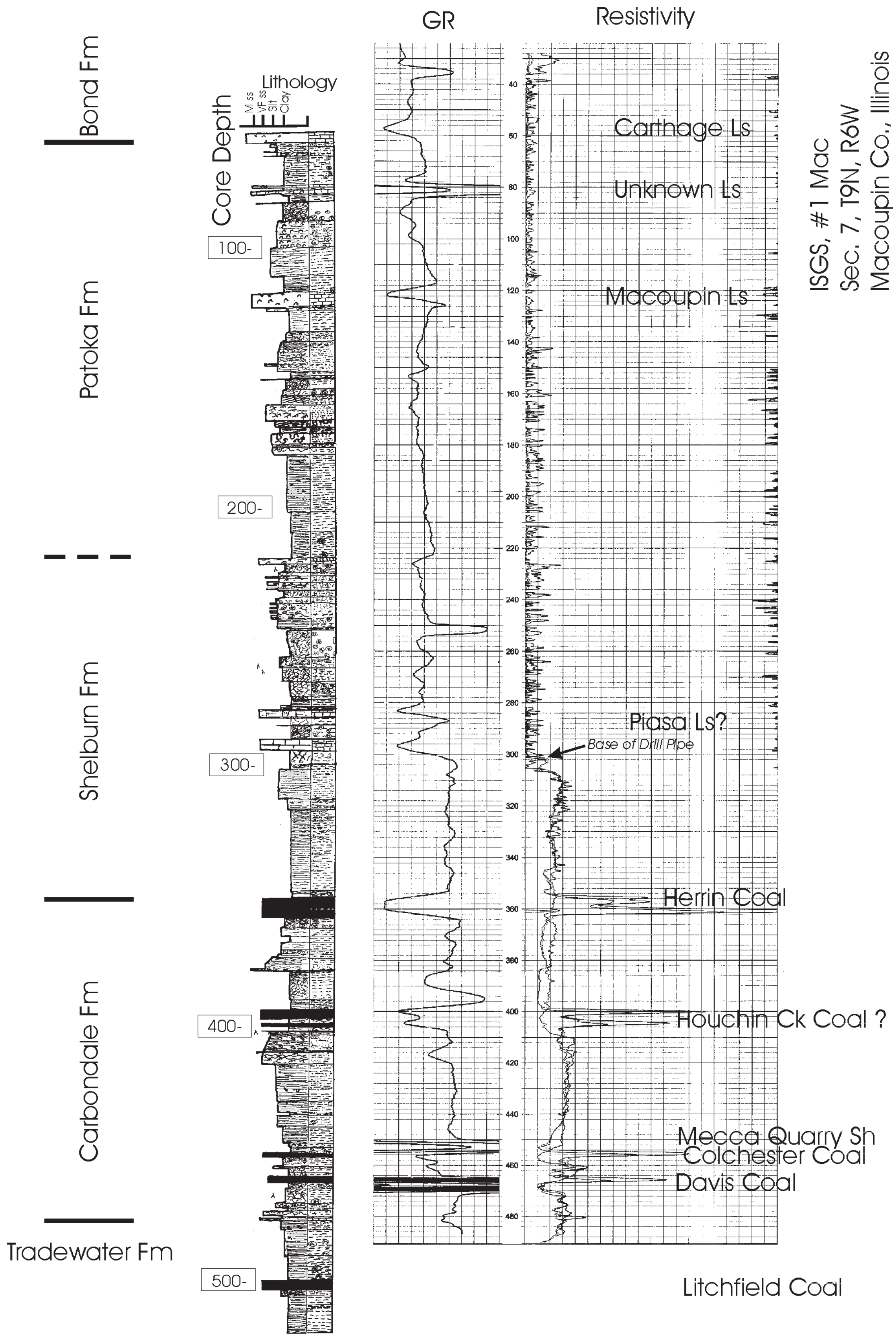


Figure 12 Lithology and geophysical logs of the Macoupin County well: ~30 to 526 ft (T.D.).

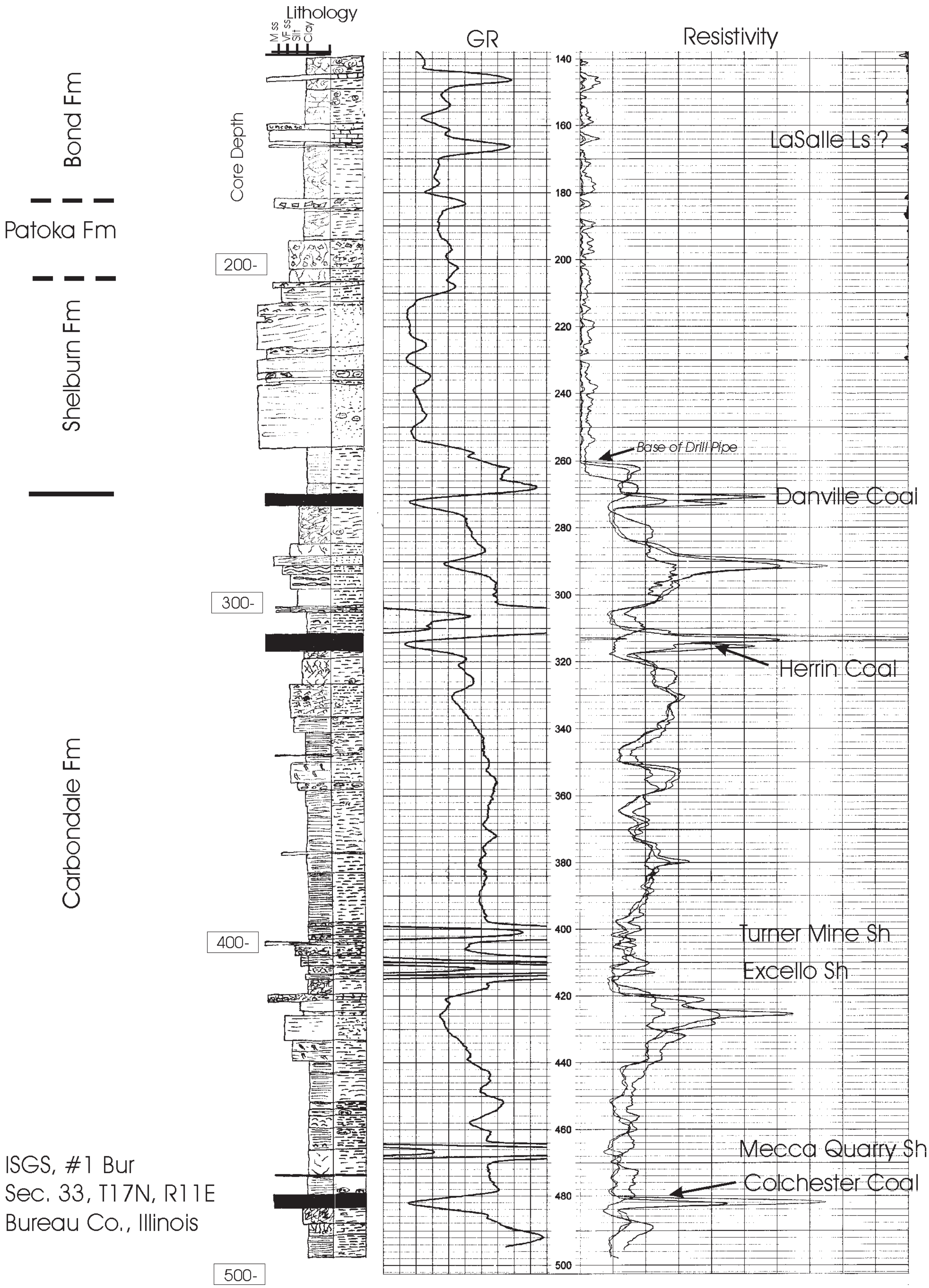


Figure 13 Lithology and geophysical logs of the Bureau County well: ~140 to 503 ft (T.D.).

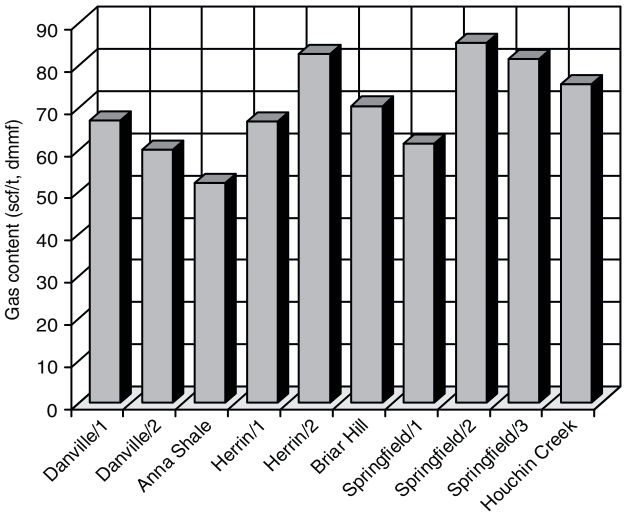
Table 5 Coal and shale samples obtained from the five ISGS test wells for gas and other analyses.

County/drilling elevation (ft)	Well name	Coal or shale/ sample no.	Sample depth (ft)	Seam or bed thickness (ft)	Sample bulk density (g/cm^3)	Sample volume (cm^3)	Sample weight (g)
Richland/506	Ely #1	Danville/1	999	2.8	1.37	1,565	2,150
	Ely #1	Danville/2	1,000	2.8	1.31	1,690	2,211
	Ely #1	Anna Shale	1,019	2.0	2.19	1,615	3,530
	Ely #1	Herrin/1	1,042	5.3	1.31	1,610	2,107
	Ely #1	Herrin/2	1,044	5.3	1.28	1,690	2,167
	Ely #1	Briar Hill	1,079	2.0	1.44	1,615	2,327
	Ely #1	Springfield/1	1,109	4.5	1.35	1,490	2,007
	Ely #1	Springfield/2	1,110	4.5	1.27	1,490	1,891
	Ely #1	Springfield/3	1,111	4.5	1.24	1,240	1,540
	Ely #1	Houchin Creek	1,160	0.8	1.51	900	1,359
Franklin/485	USX #2564-3	Chapel	640	0.8	1.40	1,400	1,958
	USX #2564-3	Danville/1	686	2.4	1.39	1,600	2,229
	USX #2564-3	Danville/2	687	2.4	1.54	1,550	2,391
	USX #2564-3	Energy Shale	784	24.0	2.49	1,600	3,979
	USX #2564-3	Herrin/1	786	9.0	1.31	1,775	2,319
	USX #2564-3	Herrin/2	787	9.0	1.31	1,750	2,299
	USX #2564-3	Herrin/3	788	9.0	1.29	1,650	2,124
	USX #2564-3	Turner Mine Shale	826	5.0	1.92	1,525	2,923
	USX #2564-3	Springfield/1	849	5.5	1.37	1,525	2,095
	USX #2564-3	Springfield/2	850	5.5	1.33	1,650	2,196
	USX #2564-3	Springfield/3	851	5.5	1.39	1,425	1,981
	USX #2564-3	Houchin Creek	912	1.3	1.35	1,650	2,220
	USX #2564-3	Survant/1	954	2.5	1.33	1,650	2,193
	USX #2564-3	Survant/2	955	2.5	1.34	1,675	2,244
	USX #2564-3	Mecca Quarry Shale	1,016	2.5	2.00	1,650	3,307
	USX #2564-3	Colchester	1,019	0.7	1.50	1,050	1,580
	USX #2564-3	Upper Dekoven/1	1,054	2.5	1.35	1,475	1,997
	USX #2564-3	Upper Dekoven/2	1,055	2.5	1.36	1,660	2,250
	USX #2564-3	Lower Dekoven	1,072	1.9	1.38	1,650	2,283
	USX #2564-3	Davis/1	1,077	2.6	1.44	1,550	2,238
	USX #2564-3	Davis/2	1,078	2.6	1.40	1,650	2,313
Clark/585	Clark #1	Danville/1	553	3.5	1.36	1,650	2,245
	Clark #1	Danville/2	554	3.5	1.34	1,650	2,204
	Clark #1	Jamestown/1	583	5.3	1.49	1,775	2,645
	Clark #1	Jamestown/2	584	5.3	1.36	1,570	2,137
	Clark #1	Jamestown/3	585	5.3	1.30	1,600	2,083
	Clark #1	Herrin	604	2.2	1.41	1,675	2,369
	Clark #1	Briar Hill/1	631	2.8	1.36	1,675	2,277
	Clark #1	Briar Hill/2	632	2.8	1.38	1,560	2,145
	Clark #1	Springfield/1	647	3.7	1.36	1,600	2,177
	Clark #1	Springfield/2	648	3.7	1.28	1,525	1,959
	Clark #1	Excello Shale	700	3.0	1.95	1,680	3,268
	Clark #1	Houchin Creek	702	1.5	1.32	1,450	1,919
	Clark #1	Survant	741	3.3	1.29	1,600	2,066
	Clark #1	Upper Seelyville	818	2.0	1.30	1,400	1,824
	Clark #1	Lower Seelyville/1	822	4.8	1.35	1,725	2,324
	Clark #1	Lower Seelyville/2	823	4.8	1.32	1,450	1,917
Macoupin/625	Mac #1	Herrin/1	360	7.7	1.34	1,550	2,075
	Mac #1	Herrin/2	361	7.7	1.32	1,700	2,241
	Mac #1	Herrin/3	363	7.7	1.29	1,600	2,063
	Mac #1	Springfield/1	402	3.1	1.35	1,650	2,225
	Mac #1	Springfield/2	403	3.1	1.32	1,600	2,112
	Mac #1	Houchin Creek	406	2.1	1.37	1,625	2,221
	Mac #1	Colchester	457	2.1	1.34	1,675	2,238
	Mac #1	Davis	466	2.0	1.36	1,620	2,202
	Mac #1	Litchfield/1	506	3.8	1.39	1,450	2,018
	Mac #1	Litchfield/2	508	3.8	1.39	1,625	2,259
Bureau/678	Bur #1	Danville/1	276	4.1	1.35	1,750	2,365
	Bur #1	Danville/2	277	4.1	1.38	1,600	2,210
	Bur #1	Herrin/1	315	4.9	1.34	1,420	1,900
	Bur #1	Herrin/2	316	4.9	1.38	1,375	1,898
	Bur #1	Herrin/3	318	4.9	1.30	1,650	2,137
	Bur #1	Colchester/1	481	3.2	1.30	1,700	2,210
	Bur #1	Colchester/2	482	3.2	1.32	1,700	2,236

Table 6 Gas contents of coal and shale samples obtained from the five ISGS test wells.

County	Well name	Coal or shale/ sample no.	As-received gas content (scf/t)	Dry, mineral matter free gas content (scf/t)			
				Lost	Desorbed	Residual	Total
Richland	Ely #1	Danville/1	49.0	1.1	55.4	10.4	66.9
	Ely #1	Danville/2	46.4	0.6	46.5	12.8	59.9
	Ely #1	Anna Shale	9.6	2.8	40.3	9.0	52.1
	Ely #1	Herrin/1	54.2	0.0	39.8	26.9	66.7
	Ely #1	Herrin/2	69.8	0.0	61.5	21.1	82.6
	Ely #1	Briar Hill	44.7	3.4	55.7	11.2	70.3
	Ely #1	Springfield/1	47.5	1.5	41.7	18.1	61.3
	Ely #1	Springfield/2	69.1	2.4	66.5	16.4	85.3
	Ely #1	Springfield/3	65.1	1.5	54.8	25.0	81.3
	Ely #1	Houchin Creek	57.6	0.7	70.5	4.3	75.5
Franklin	USX #2564-3	Chapel	43.2	0.0	39.8	18.6	58.4
	USX #2564-3	Danville/1	68.2	0.3	56.9	31.4	88.6
	USX #2564-3	Danville/2	61.3	0.1	66.6	34.2	100.9
	USX #2564-3	Energy Shale	11.7	NA	NA	NA	NA
	USX #2564-3	Herrin/1	117.2	1.7	94.3	48.0	144.0
	USX #2564-3	Herrin/2	110.1	1.6	90.4	35.8	127.8
	USX #2564-3	Herrin/3	101.2	0.1	72.6	45.7	118.4
	USX #2564-3	Turner Mine Shale	33.0	0.5	59.2	52.1	111.8
	USX #2564-3	Springfield/1	120.0	1.3	102.6	48.6	152.5
	USX #2564-3	Springfield/2	114.6	0.9	88.2	46.0	135.1
	USX #2564-3	Springfield/3	107.7	1.0	85.6	40.5	127.1
	USX #2564-3	Houchin Creek	74.6	0.4	55.4	36.0	91.8
	USX #2564-3	Survant/1	65.3	0.4	66.7	10.2	77.3
	USX #2564-3	Survant/2	57.1	0.6	56.8	11.7	69.1
	USX #2564-3	Mecca Quarry Shale	21.7	0.0	57.1	36.6	93.7
	USX #2564-3	Colchester	46.5	0.4	43.1	20.1	63.6
	USX #2564-3	Upper Dekoven/1	62.0	1.5	46.4	28.4	76.3
	USX #2564-3	Upper Dekoven/2	54.4	1.2	44.3	21.6	67.1
	USX #2564-3	Lower Dekoven	63.1	0.6	60.6	18.6	79.8
	USX #2564-3	Davis/1	70.1	1.6	58.9	34.5	95.0
	USX #2564-3	Davis/2	75.8	2.0	70.0	33.2	105.2
Clark	Clark #1	Danville/1	46.1	0.7	49.0	13.5	63.2
	Clark #1	Danville/2	48.9	0.6	42.8	18.2	61.6
	Clark #1	Jamestown/1	41.5	0.0	40.3	23.0	63.3
	Clark #1	Jamestown/2	45.9	0.0	33.5	25.2	58.7
	Clark #1	Jamestown/3	50.1	0.1	24.8	34.5	59.4
	Clark #1	Herrin	71.9	1.3	75.1	20.5	96.9
	Clark #1	Briar Hill/1	69.6	1.1	68.9	19.6	89.6
	Clark #1	Briar Hill/2	71.0	0.3	72.1	26.0	98.4
	Clark #1	Springfield/1	77.9	1.5	71.7	19.7	92.9
	Clark #1	Springfield/2	85.9	0.9	76.3	24.0	101.2
	Clark #1	Excello Shale	40.7	0.2	95.4	49.7	145.3
	Clark #1	Houchin Creek	60.9	1.0	49.3	21.5	71.8
	Clark #1	Survant	102.4	1.6	98.3	26.8	126.7
	Clark #1	Upper Seelyville	109.8	2.0	98.8	34.0	134.8
	Clark #1	Lower Seelyville/1	130.3	3.4	142.0	27.8	173.2
	Clark #1	Lower Seelyville/2	119.2	1.9	110.5	26.4	138.8
Macoupin	Mac #1	Herrin/1	27.4	0.2	33.0	4.9	38.1
	Mac #1	Herrin/2	31.2	0.1	37.0	8.4	45.5
	Mac #1	Herrin/3	27.9	0.0	25.8	10.7	36.5
	Mac #1	Springfield/1	35.8	1.0	37.5	12.7	51.2
	Mac #1	Springfield/2	37.3	0.7	36.1	12.6	49.4
	Mac #1	Houchin Creek	39.0	1.2	37.4	14.2	52.8
	Mac #1	Colchester	42.9	1.4	47.4	10.9	59.7
	Mac #1	Davis	50.3	1.8	56.8	10.0	68.6
	Mac #1	Litchfield/1	59.8	3.7	66.2	10.2	80.1
	Mac #1	Litchfield/2	58.6	1.4	67.3	15.0	83.7
Bureau	Bur #1	Danville/1	3.7	0.0	1.5	4.0	5.5
	Bur #1	Danville/2	3.9	0.0	1.8	4.0	5.8
	Bur #1	Herrin/1	3.1	0.0	1.0	3.6	4.6
	Bur #1	Herrin/2	3.4	0.0	1.4	3.6	5.0
	Bur #1	Herrin/3	3.1	0.2	0.8	3.6	4.6
	Bur #1	Colchester/1	4.0	0.2	1.3	3.7	5.2
	Bur #1	Colchester/2	3.6	0.1	0.9	3.7	4.7
Mean[1]			66.5				85.0
Standard deviation[1]			40.2				31.0

[1]Excluding shales and Bureau County samples.



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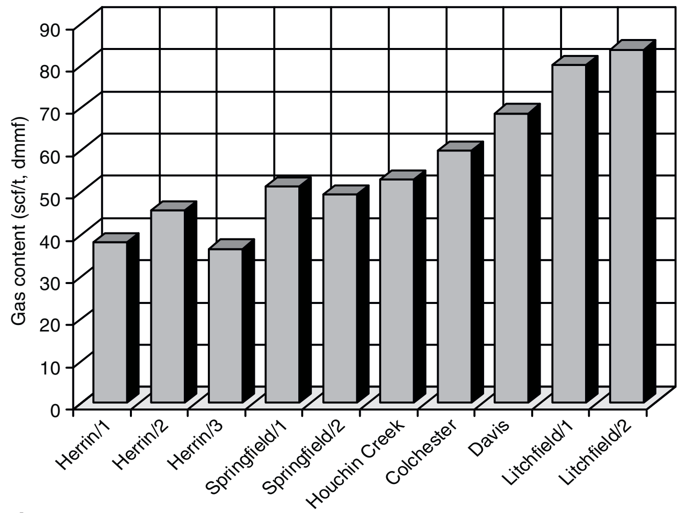

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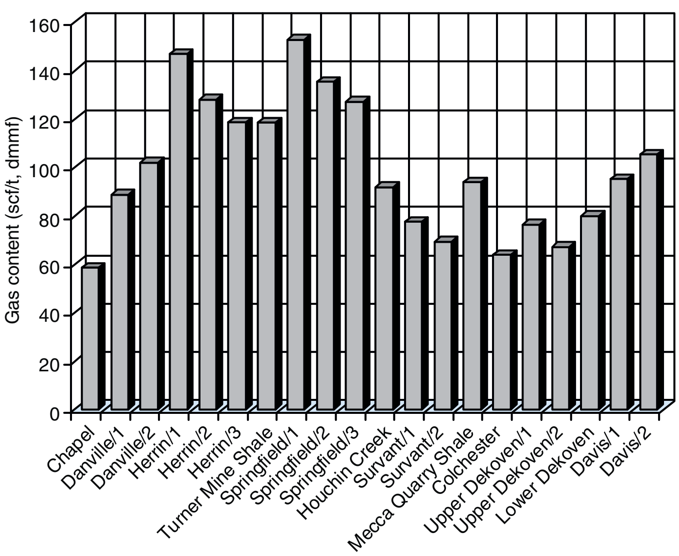

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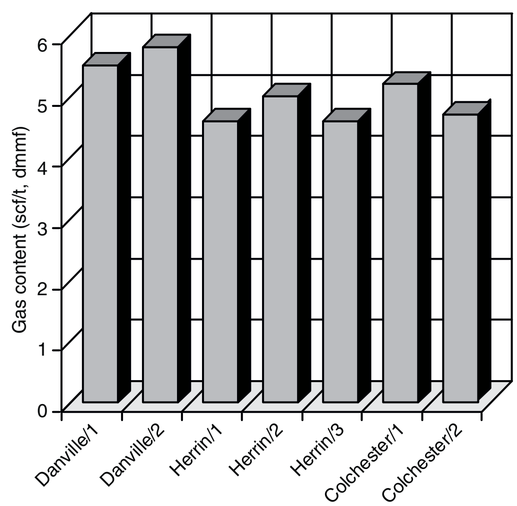

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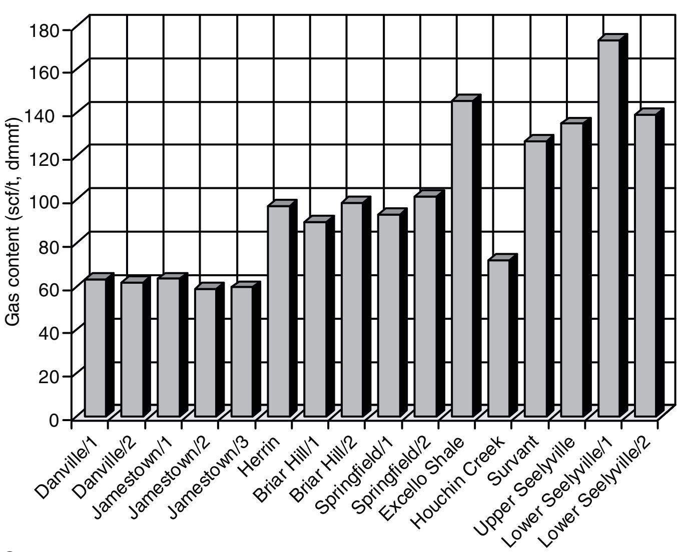

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Figure 14 Gas contents of coal and shale samples from (a) Ely #1 well in Richland County, (b) USX #2564-3 well in Franklin County, (c) Clark #1 well in Clark County, (d) Mac #1 well in Macoupin County, and (e) Bur #1 well in Bureau County. Depth increases to the right. Note that vertical scales vary.

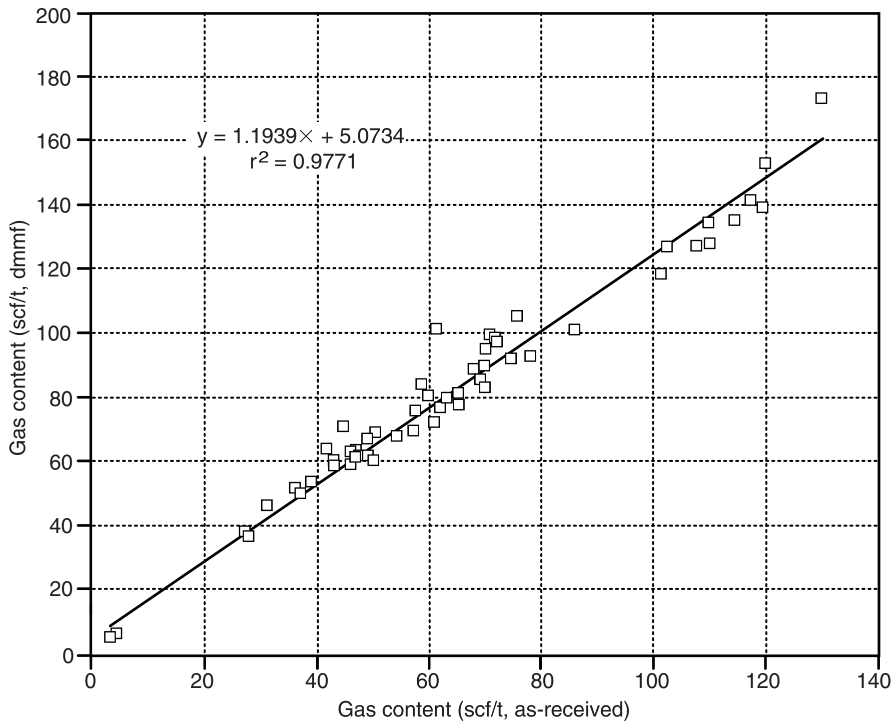


Figure 15 Relationship between gas contents on as-received and dmmf bases for all coal samples from all five wells.

low gas contents of the deeper coals in the two wells from Franklin and Richland Counties.

Coal Gas Variations of Individual Seams

Danville, Herrin, and Springfield seams were present in most of the test well locations. The gas content of each coal seam increases with seam depth, excluding the Richland County location (fig. 18). The variation of gas content of each seam with depth (fig. 18) is similar to the variation of vitrinite reflectance with depth (fig. 19), and gas contents of individual seams generally increase as vitrinite reflectance increases (fig. 20). Thus, vitrinite reflectance (rank) probably is a reasonable indicator of the gas content of a given coal seam in Illinois. Because of increased hydrostatic pressure, the depth of a given seam may also be a reasonable indication of the gas content as long as the coal rank increases with seam depth. Exploration, therefore, should target deeper coals in more mature areas and perhaps also some shallower coals with high permeabilities and moderate gas contents.

New versus Previously Published Gas Contents and Gas Resource Estimations

Coal gas content data from previous studies (table 1) and from this project can be compared for the Richland and Franklin County locations. Although there were no previous data from Richland County, previous data from a Clay County location can be compared with the new Richland County data because the old and new well locations are only about 10 miles apart and both are on the western flank of the Clay City Anticline. The comparison of old and new data suggests that Illinois coals may contain 25 to 100% more gas than was indicated by previous desorption tests (fig. 21), especially in the southern and southeastern portions of the coal field. As mentioned earlier, the past desorption tests likely underestimated the gas contents because of possible leaks from the canisters, underestimation of the lost and residual gases, and improper monitoring and accounting for canister and ambient temperatures and pressures.

The total coal gas resources of 21 Tcf previously estimated for the entire Illinois Basin was based on 159 billion tons of coal in the combined Danville, Springfield, and Herrin seams and the maximum gas contents (116 to 147 scf/t) measured for the three seams in Illinois, Indiana, and Kentucky (Archer and Kirr 1984). This gas resource figure would be much higher if the same formula were to be applied to the recent coal resource estimates of 211.4, 34.1, and 38.5 billion tons for Illinois, Indiana, and Kentucky, respectively. However, calculations based on the maximum gas contents may overestimate the total gas resources of a coal basin. Multiplying the average gas content by the amount of coal resources would yield a more reasonable estimate of the gas resource volume. For example, for the Illinois portion of the basin, the newly determined average gas content

Table 7 Vitrinite reflectance and petrographic composition of coal samples obtained from the five ISGS test wells.[1]

County	Well name	Coal/ sample no.	Vitrinite reflectance (% R_m)[2]	Petrographic composition (% volume): Vitrinite macerals Total	Vitrinite macerals Desmocollinite	Liptinite macerals	Inertinite macerals	Mineral matter
Richland	Ely #1	Danville/1	0.52	86.6	19.4	3.2	5.2	5.0
	Ely #1	Danville/2	0.51	87.4	16.6	6.8	3.2	2.6
	Ely #1	Herrin/1	0.56	87.4	23.4	4.4	6.2	2.0
	Ely #1	Herrin/2	0.53	86.7	23.4	6.6	5.5	1.2
	Ely #1	Springfield/1	0.52	78.8	18.8	8.0	7.6	5.6
	Ely #1	Springfield/2	0.53	80.0	26.8	4.4	14.0	1.6
	Ely #1	Houchin Creek	0.52	79.8	20.2	4.8	5.8	9.6
Franklin	USX #2564-3	Danville/1	0.58	92.4	18.8	2.4	1.6	3.6
	USX #2564-3	Danville/2	0.62	71.6	15.6	3.2	8.8	16.4
	USX #2564-3	Herrin/1	0.62	86.0	29.2	6.8	5.6	1.6
	USX #2564-3	Herrin/3	0.64	90.4	16.7	6.5	1.8	1.2
	USX #2564-3	Springfield/1	0.62	80.0	21.4	6.0	8.4	5.6
	USX #2564-3	Springfield/3	0.63	87.8	24.4	6.4	4.4	1.4
	USX #2564-3	Houchin Creek	0.60	88.8	19.2	3.6	2.4	5.2
	USX #2564-3	Survant/1	0.61	82.8	27.8	8.4	7.4	1.6
	USX #2564-3	Upper Dekoven/1	0.59	82.8	21.2	7.6	5.2	4.4
	USX #2564-3	Lower Dekoven	0.62	80.4	20.4	7.6	7.2	4.8
	USX #2564-3	Davis/2	0.59	83.2	20.0	5.8	6.2	4.8
Clark	Clark #1	Danville/1	0.55	78.4	17.2	5.2	10.4	6.0
	Clark #1	Jamestown/1	0.56	70.4	26.4	2.6	1.4	25.6
	Clark #1	Herrin	0.59	78.8	19.2	6.8	8.4	6.0
	Clark #1	Briar Hill/1	0.56	80.2	20.2	5.4	5.2	9.2
	Clark #1	Springfield/1	0.62	71.8	32.2	7.0	18.2	3.0
	Clark #1	Houchin Creek	0.57	86.6	30.6	3.0	7.0	3.4
	Clark #1	Survant	0.69	78.4	28.2	11.0	7.8	2.8
	Clark #1	Upper Seelyville	0.56	84.4	29.6	4.8	8.0	2.8
	Clark #1	Lower Seelyville/1	0.58	86.8	34.6	2.8	3.6	6.8
Macoupin	Mac #1	Herrin/2	0.55	77.0	19.2	6.4	6.4	10.2
	Mac #1	Springfield/1	0.52	79.6	26.4	8.2	3.6	8.6
	Mac #1	Houchin Creek	0.49	76.0	33.4	7.2	7.4	9.4
	Mac #1	Colchester	0.51	78.4	27.4	6.4	10.2	5.0
	Mac #1	Davis	0.48	77.6	31.6	2.6	6.2	13.6
	Mac #1	Litchfield/2	0.50	77.6	26.8	7.4	5.8	9.4
Bureau	Bur #1	Danville/1	0.49	81.8	22.8	3.4	3.6	11.2
	Bur #1	Herrin/1	0.50	84.4	27.8	7.0	2.8	5.8
	Bur #1	Colchester/1	0.49	80.4	24.2	4.0	5.4	10.2
Mean			0.56	81.7	23.9	5.7	6.3	6.3
Standard deviation			0.05	5.2	5.2	2.0	3.4	5.0

[1]For additional information on maceral composition of Illinois coals, see Harvey and Dillon (1985).
[2]R_m, Random mean vitrinite reflectance.

(table 6) multiplied by the 211.4 billion tons of coal yields 14 Tcf of coal gas on an as-received basis. These gas resource values are likely to be conservative because (1) the measured gas contents may be low because of unaccounted for gas loss during drilling, and (2) statewide averaging of the gas contents may underestimate the amount of coal gas in southern Illinois where the majority of the state's coal resources are located. The amount of coal gas resources of Indiana and western Kentucky must be calculated and added to the amount for Illinois to estimate the coal gas in place for the entire Illinois Basin. Sufficient or reliable data on average coal gas contents are lacking for the Indiana and western Kentucky coals. However, these coals may have greater average gas contents than Illinois coals because they are located mostly in the southern portion of the basin where the coal rank in general is relatively high. For example, coal gas contents of up to 230 scf/t reported for the southern part of the Illinois Basin (Tedesco 2003) were presumably for Indiana or western Kentucky coals. If the average gas content is assumed to be 100 to 150 scf/t, approximately 73 billion tons of coal in Indiana and western Kentucky portions of the basin probably hold gas resources of 7 to 11 Tcf in addition to the estimated 14 Tcf of gas held in Illinois coals, yielding 21 to 25 Tcf of CBM resources for the entire basin. Calculating a more accurate gas-in-place volume for the state and the basin would require more data to enable the use of the modified resource equations described by Scott et al. (1995).

Gas Composition

Excluding the Bureau County well, coal gas samples contained 56 to 92% combustible gases (table 8; fig. 22), and shale samples contained about 57 to 96% combustible gases.

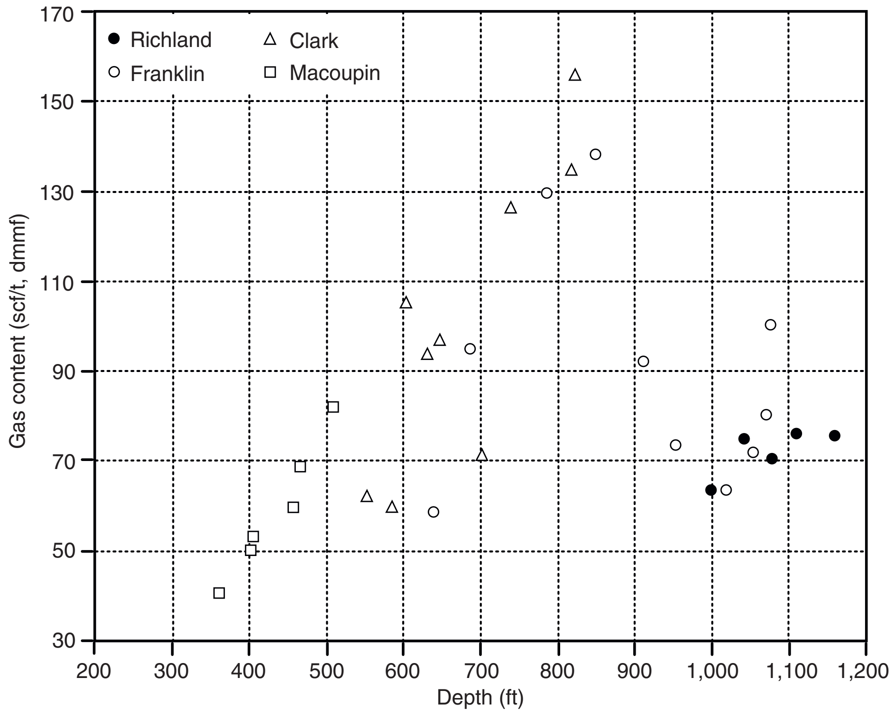


Figure 16 Gas content versus depth for multiple coal seams in individual wells from four counties.

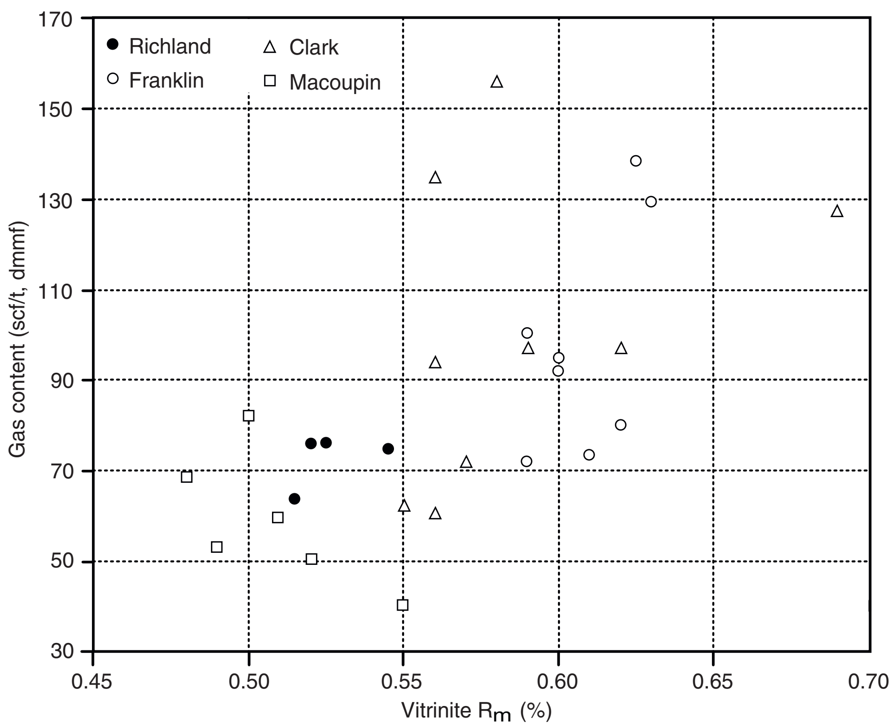


Figure 17 Gas content versus vitrinite reflectance (R_m) in individual wells from four counties.

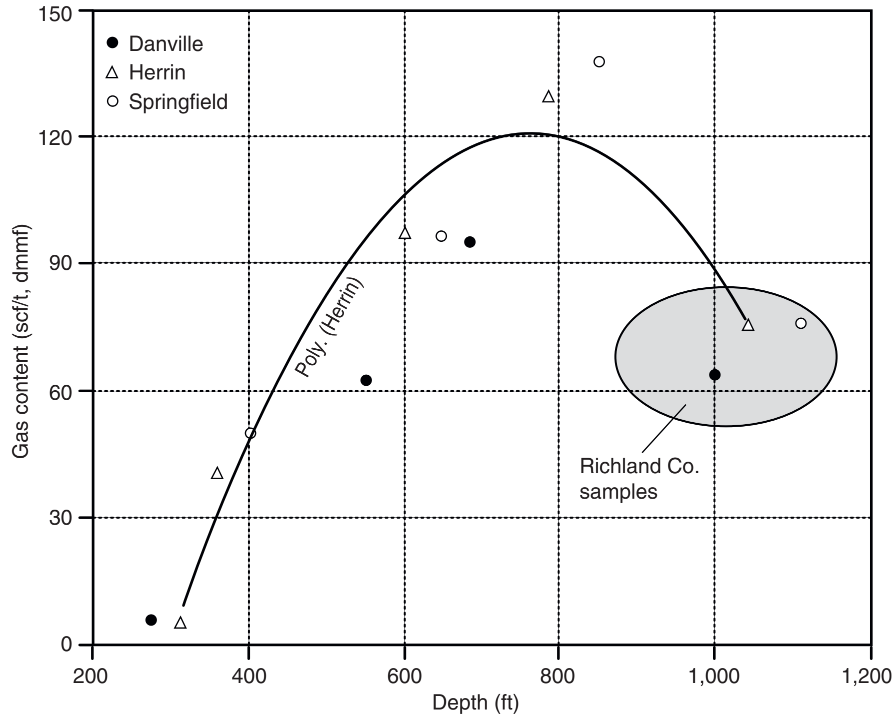


Figure 18 Gas content versus depth for individual seams. Poly., polynomial trend.

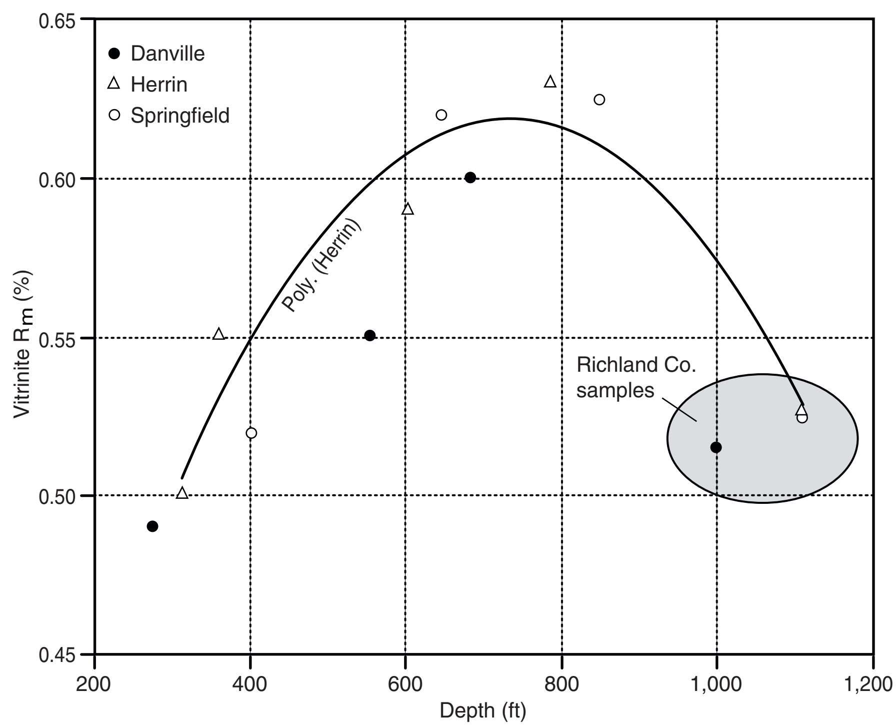


Figure 19 Vitrinite reflectance (R_m) versus depth for individual seams. Poly., polynomial trend.

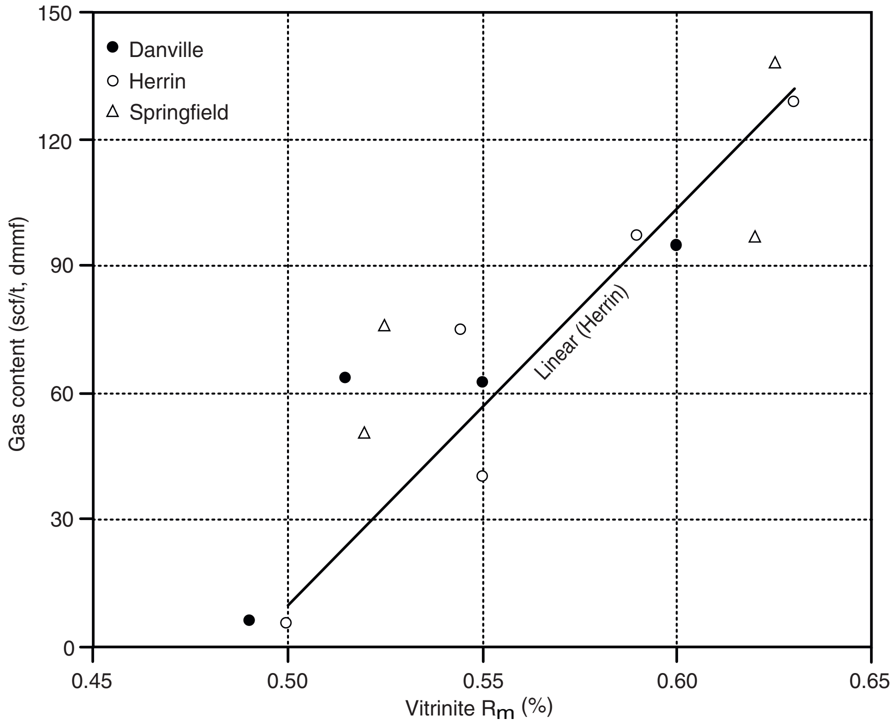


Figure 20 Gas content versus vitrinite reflectance (R_m) for individual seams.

Most of the combustible gas in the coals was CH_4. Other combustibles, which are higher molecular weight hydrocarbons (C_{2+}; wet gases), ranged from 0.05 to 3.95% of the total gas, excluding the Bureau County well. Gas dryness index (GDI) was 0.94 to 1.00, making the combustible gases classified as dry (GDI = 0.94 to 0.98) to very dry (GDI >0.99). The inert gases in the mixture were mostly N_2 at 2.6 to 41.0% and lesser amounts of CO_2 at 1 to 4.2%. Very low combustible contents and high N_2 and CO_2 contents in the Bureau County samples perhaps suggest that these two gases were removed less efficiently than combustible gases during depressurization and water flushing. Another scenario for N_2 enrichment in the Bureau County coals might have involved air intrusion through groundwater circulation after degassing. The oxygen in the air would probably have been consumed by aerobic bacteria within a short distance of outcrop, leaving behind N_2 that was carried to the coal. For the other four wells, the combustible contents increased with depth between 360 ft and about 800 ft and were mostly above 80% for coals deeper than 600 ft (fig. 22). Again, air nitrogen mixed in meteoric water recharge probably contacts the coals through groundwater circulation while the oxygen in the air is consumed by aerobic bacteria in shallow depths before reaching the coals, which results in the adsorption of the inert nitrogen into the coal and thereby the dilution of the combustible gases. This process loses its effect as depth increases. Therefore, delineating local hydrogeological conditions is one of the important studies to be done prior to commercial CBM development in an area.

It should be noted that ambient air trapped in the canister when it was sealed might not have been fully displaced fast enough to prevent partial oxidation of the coal. The partial oxidation of the coal cores in the canisters probably left behind some nitrogen gas that was counted as coal gas nitrogen instead of air nitrogen during analysis, which means that the actual nitrogen contents may be somewhat lower and the actual combustible gas contents somewhat higher than the corresponding values given in table 8 and figure 22. Examining successive gas samples from each coal produced mixed results about the extent of coal oxidation during desorption tests because the rate and degree of oxidation and N_2 adsorption likely varied from coal to coal.

Gas Origin

The isotopic composition of the carbon and hydrogen of methane is useful in differentiating biogenic methane from thermogenic methane in geological environments (Schoell 1980). Methane generated thermogenically is expected to be enriched in heavier carbon isotope (^{13}C) and deuterium (D), the heavy hydrogen isotope. The isotopic compositions ($\delta^{13}C$ and δD) of all samples are given in table 8 and plotted in figure 23. The $\delta^{13}C$ and δD values of thermogenic methane are heavier than –55‰ and –260‰, respectively, while microbial methane is lighter in $\delta^{13}C$, δD, or both. In some cases, the $\delta^{13}C$ values of biogenic and thermogenic gases overlap the range of –55 to –39 (Scott et al. 1994). The $\delta^{13}C$ values of the gas samples from this study, however, are all lighter (more negative) than –55

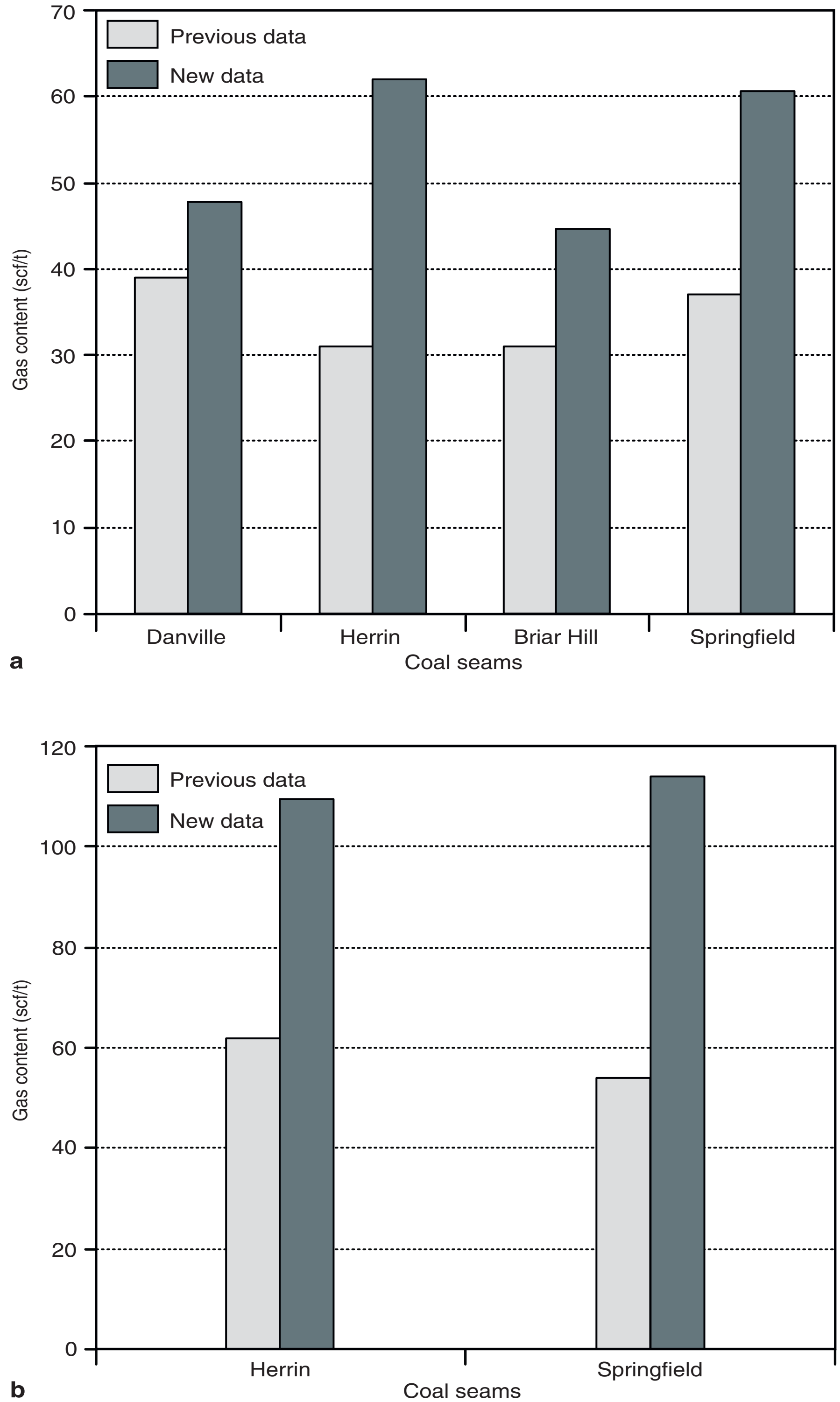


Figure 21 Newly and previously measured gas contents for selected Illinois coals (a) in Richland and Clay Counties and (b) in Franklin County. All data were adjusted to an as-received basis and standard temperature and pressure conditions of 60°F and 1 atmosphere before plotting.

Table 8 Chemical and isotopic compositions of gas from coal seams and shales from the five ISGS test wells. Most values are averages of multiple measurements.

			Chemical composition (%)					Gas dryness	CH_4 isotopic composition (‰)	
County	Well name	Coal/shale	N_2	CO_2	CH_4	C_{2+}	CH_4+(C_{2+})	index (C_1/C_{1-5})	$\delta^{13}C_{PDB}$	D_{SMOW}
Richland	Ely #1	Danville	15.63	1.84	81.12	1.41	82.53	0.98	-68.2	-211.6
	Ely #1	Anna Shale	20.85	9.72	65.50	3.93	69.43	0.94	ND	ND
	Ely #1	Herrin	16.98	2.16	79.85	1.01	80.86	0.99	-66.9	-208.5
	Ely #1	Briar Hill	20.84	2.20	75.52	1.44	76.96	0.98	-67.5	-211.8
	Ely #1	Springfield	19.76	1.73	77.59	0.92	78.51	0.99	-65.4	-211.5
	Ely #1	Houchin Creek	14.81	2.63	81.02	1.54	82.56	0.98	-65.5	-210.1
Franklin	USX #2564-3	Danville	12.91	1.38	84.84	0.88	85.72	0.99	-65.9	-199.6
	USX #2564-3	Herrin	8.88	1.08	89.80	0.24	90.04	1.00	-64.5	-200.6
	USX #2564-3	Turner Mine Shale	2.63	1.70	93.76	1.91	95.67	0.98	ND	ND
	USX #2564-3	Springfield	11.11	0.89	87.92	0.07	87.99	1.00	-65.1	-201.5
	USX #2564-3	Houchin Creek	11.95	1.23	85.97	0.85	86.82	0.99	-64.8	-204.5
	USX #2564-3	Survant	12.40	2.06	83.61	1.93	85.54	0.98	-63.7	-202.9
	USX #2564-3	Mecca Quarry Shale	42.17	0.65	55.02	2.15	57.17	0.96	-65.7	-202.1
	USX #2564-3	Colchester	8.88	1.42	87.11	2.58	89.69	0.97	-66.6	-205.4
	USX #2564-3	Upper Dekoven	16.61	1.41	80.25	1.74	81.99	0.98	-64.5	-204.0
	USX #2564-3	Lower Dekoven	12.54	1.43	84.35	1.67	86.02	0.98	-63.6	-204.2
	USX #2564-3	Davis	14.66	1.22	82.73	1.39	84.12	0.98	-63.4	-204.0
Clark	Clark #1	Danville	27.13	2.02	67.72	3.13	70.85	0.96	-57.9	-208.0
	Clark #1	Jamestown	24.63	1.93	70.50	2.94	73.44	0.96	-60.3	-215.4
	Clark #1	Herrin	16.30	2.74	77.01	3.95	80.96	0.95	-60.7	-214.1
	Clark #1	Briar Hill	11.19	2.87	82.36	3.58	85.94	0.96	-61.0	-224.0
	Clark #1	Springfield	14.87	2.34	80.64	2.15	82.79	0.97	-61.2	-224.0
	Clark #1	Excello Shale	25.41	1.55	70.24	2.80	73.04	0.96	-59.0	-208.6
	Clark #1	Houchin Creek	18.21	1.33	78.60	1.86	80.46	0.98	-59.2	-207.8
	Clark #1	Survant	9.11	1.50	89.26	0.13	89.39	1.00	-59.8	-206.6
	Clark #1	Upper Seelyville	15.83	1.54	82.38	0.25	82.63	1.00	-60.1	-208.3
	Clark #1	Lower Seelyville	6.77	1.28	91.89	0.05	91.94	1.00	-60.1	-205.9
Macoupin	Mac #1	Herrin	41.07	3.36	54.44	1.13	55.57	0.98	-69.6	-223.3
	Mac #1	Springfield	37.22	2.88	59.20	0.70	59.90	0.99	-70.3	-2317.
	Mac #1	Houchin Creek	29.63	3.19	66.04	1.15	67.19	0.98	-68.6	-231.5
	Mac #1	Colchester	22.86	4.20	71.16	1.78	72.94	0.97	-65.0	-216.6
	Mac #1	Davis	29.68	3.59	65.12	1.60	66.72	0.98	-63.8	-213.5
	Mac #1	Litchfield	23.76	1.41	74.12	0.70	74.82	0.99	-60.9	-216.9
Bureau	Bur #1	Danville	91.85	4.06	3.94	0.15	4.09	0.95	-73.7	-241.2
	Bur #1	Herrin	74.69	18.52	3.51	3.29	6.80	0.52	ND	ND
	Bur #1	Colchester	0.00	82.95	0.00	17.05	17.05	0.00	ND	ND
Mean[1]			18.10	1.98	78.31	1.43	79.74	0.98	-63.9	-211.3
Standard deviation[1]			8.46	0.83	9.17	1.01	10.18	0.01	3.3	8.7

[1]Excluding shales and Bureau County samples.

and fall within or near the microbial CO_2 reduction field (fig. 23). The $\delta^{13}C$ values of CMM from abandoned mines (table 9) are also within the microbial range. These various isotopic data suggest that CBM in the study areas formed primarily by microbial processes involving CO_2 reduction with the possibility of small contributions from thermogenic processes. A mixed origin, instead of predominantly biogenic origin, is inferred if the presence of 1 to 4% C_{2+} hydrocarbons as an indication of thermal origin and the relationship between $\delta^{13}C$ of methane and the concentration of C_{2+} compounds in the gases are used (fig. 24). The biogenic methane is likely a late stage (secondary) biogenic gas associated with meteoric recharge (Scott et al. 1994). The exact timing of its formation is difficult to establish without understanding the current and past hydrogeological conditions. Isotopic values of two shale gases also plot in the microbial field or in the transition zone (figs. 23 and 24), suggesting that gases from the coals and shales were generated similarly.

Minimum Gas Saturation of Coal Seams

The amount of gas currently present in coal does not necessarily indicate its gas storage capacity. If the amount of gas in a coal is less than its storage capacity at reservoir pressure and temperature, the coal is undersaturated with respect to the gas. Quantifying coal gas saturation (the measured gas as the percentage of the storage capacity at reservoir pressure and temperature) is important for CBM production and reserve assessment.

Methane adsorption isotherms of selected coals (fig. 25) were produced at reservoir temperatures to determine the variability of gas storage capacity with pressure. The gas saturation of the coals range from about 5 to 70%

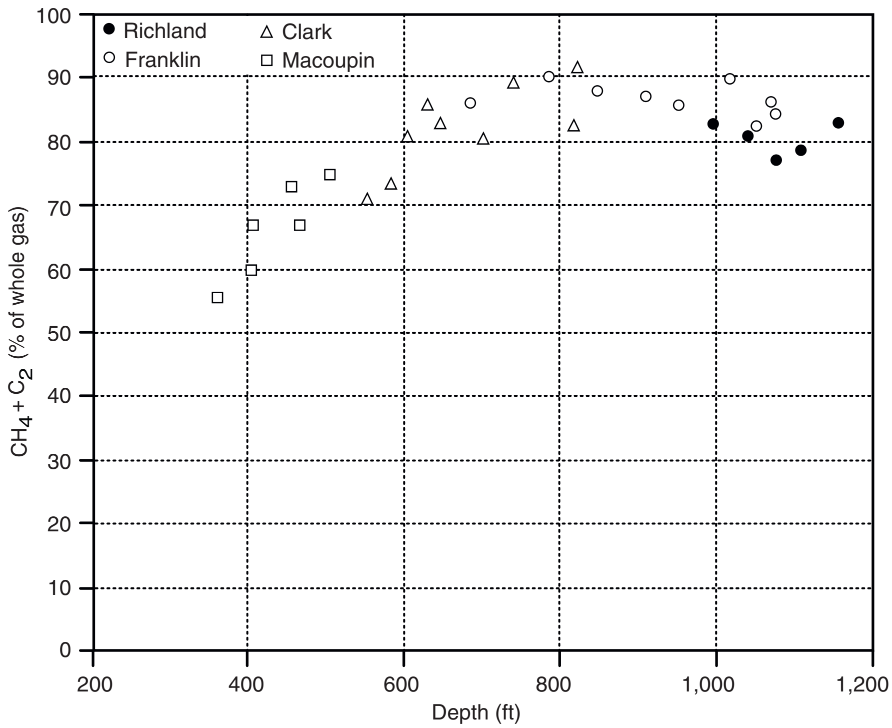


Figure 22 Variability of combustible contents of coal gases with depth in individual wells.

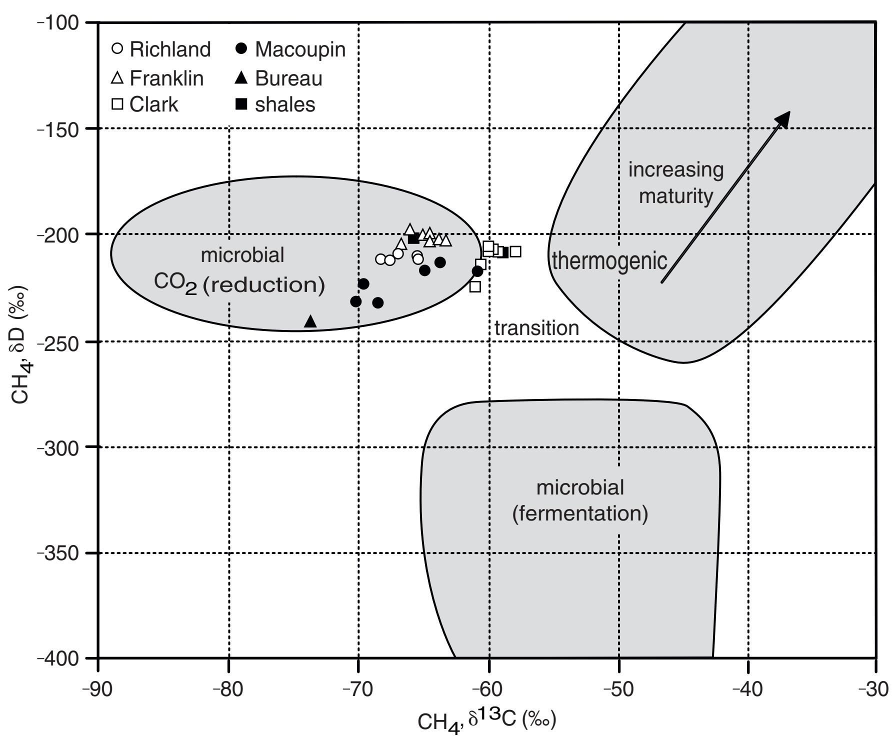


Figure 23 Methane carbon and hydrogen isotopic compositions of coals from five Illinois counties, one shale in Franklin County, and one shale in Clark County. The fields of thermogenic and biogenic gases were modified from Rice (1993) and Coleman et al. (1995).

Table 9 Previously determined carbon isotopic composition of coalbed methane from some Illinois coal cores and of coal mine methane from abandoned Illinois mines.[1]

County	Drill hole or coal comapany	Mine name, mine index (MI)	Coal seam	Depth (ft)	Coal thickness (ft)	Gas type	Samples analyzed (no.)	$\delta^{13}C$ of CH_4 (‰)
Coles	Charleston DH	–	Danville	964	2.6	desorbed	9	–62.9 to –61.4
Coles	Charleston DH	–	Danville	964	2.6	residual	1	–59.8
Coles	Charleston DH	–	Herrin	1,066	2.6	desorbed	4	–57.4 to –55.1
Coles	Charleston DH	–	Herrin	1,066	2.6	residual	1	–52.1
Coles	Charleston DH	–	Springfield	1,093	1.3	desorbed	3	–57.1 to –56.5
Coles	Charleston DH	–	Springfield	1,093	1.3	residual	1	–55.4
Coles	Charleston DH	–	Springfield	1,093	3.3	desorbed	7	–57.3 to –55.6
Coles	Charleston DH	–	Springfield	1,093	3.3	residual	1	–54.5
Christian	Joe Simkins #1 Kinkaid	Peabody #7, MI 2040	Herrin	348		mine gas	1	–67.7
Clinton	Pessina #1 Kampwerth	B- Buxton #3, MI 85	Herrin	348	7.9	mine gas	1	–65.1
Gallatin	Peabody CC	Eagle #2, MI 898	Springfield	249	5.6	fault seepage	1	–61.6
Montgomery	G. Stieren	Crown #1, MI 707	Herrin	354	6.9	mine gas	3	–69.6 to –69.1
Saline	A. Farris	Dering #2, MI 125	Springfield	456	5.9	mine gas	3	–62.7 to –60.0
Saline	Wasson Mine shaft	Wasson #1, MI 45	Springfield	325	5.2	mine gas	1	–62.3
Saline	M.L. Devillez #3	Wasson #1, MI 45	Springfield	361	5.2	mine gas	1	–62.2
Saline	Cahaba #1 Willis	Eldorado #20, MI 46	Springfield	417	5.9	mine gas	5	–61.8 to –60.7
Saline	P. Barrett, Schlafly #1	Dering #2, MI 125	Springfield	456	5.9	mine gas	1	–63.6
Saline	Jade Oil & Gas	Dering #2, MI 125	Springfield	456	5.9	mine gas	1	–62.2
Saline	Dan January	O'Gara #10, MI 799	Springfield	397	5.6	mine gas	1	–61.9
Saline	J. Wilson, Sutton #1P	O'Gara #8, MI 800	Springfield	404	5.6	mine gas	3	–61.5 to –60.5

[1]Popp et al. (1979) and ISGS database.

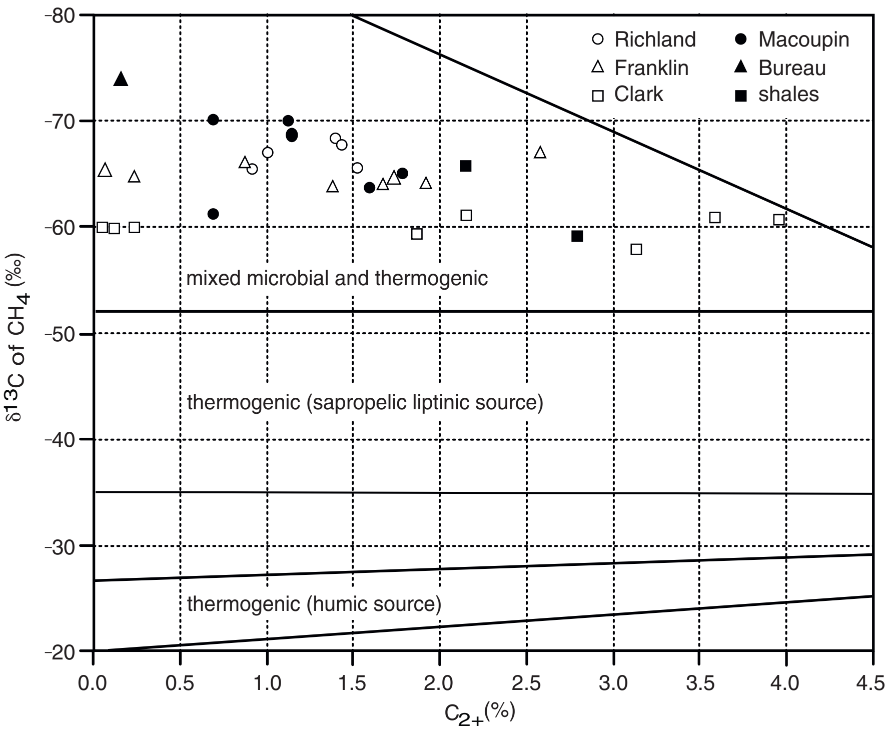


Figure 24 Carbon isotopic composition of methane versus wet gas content in coals from five Illinois counties, one shale in Franklin County, and one shale in Clark County. The fields of thermogenic and mixed microbial-thermogenic gases are from Rice (1993).

(table 10; fig. 26). As a result of using pure methane instead of actual coal gas composition in the production of the adsorption isotherms, the calculated gas saturation values may be slightly high, but very close to the actual values. Generating and entrapping large amounts of thermogenic gas by coal should result in full gas saturation. The fact that all of the coals tested are undersaturated with respect to gas is consistent with the results of methane isotopic analysis, suggesting the presence of very little, if any, thermogenic gas held in the coals tested. Thermogenic methane generation and loss apparently preceded secondary biogenic methane generation. A combination of two processes may be responsible for the insufficient thermogenic gas in these coals: (1) the coals, having vitrinite reflectance of 0.48 to 0.69, have not reached a thermal maturity level to generate large amounts of thermogenic gas, and (2) basinal fluid flow during the deep burial may have taken away at least some of the generated gas before it was adsorbed on coal micropore surfaces. A long-range, northward basinal water flow in the Illinois Basin set up by tectonic uplift of the Pascola Arch during the Mesozoic was documented by Bethke and Marshak (1990). Basinal fluids circulating in the deep parts of the Illinois Basin were saline (Stueber et al. 1993, Demir and Seyler 1999) and thus not likely to have dissolved any noticeable methane in a short period of time. However, dissolving and removing minute quantities of gas over geologic time can result in the removal of large quantities of gas. Alternatively, the gas content might have been lowered by natural water flushing in areas where fresh or relatively fresh groundwater circulates along faults or high-permeability zones. A third hypothesis is that some gas was lost during drilling of the coals; high-pressure water circulation through the drill bit could have displaced some gas, especially gas stored in the cleat system.

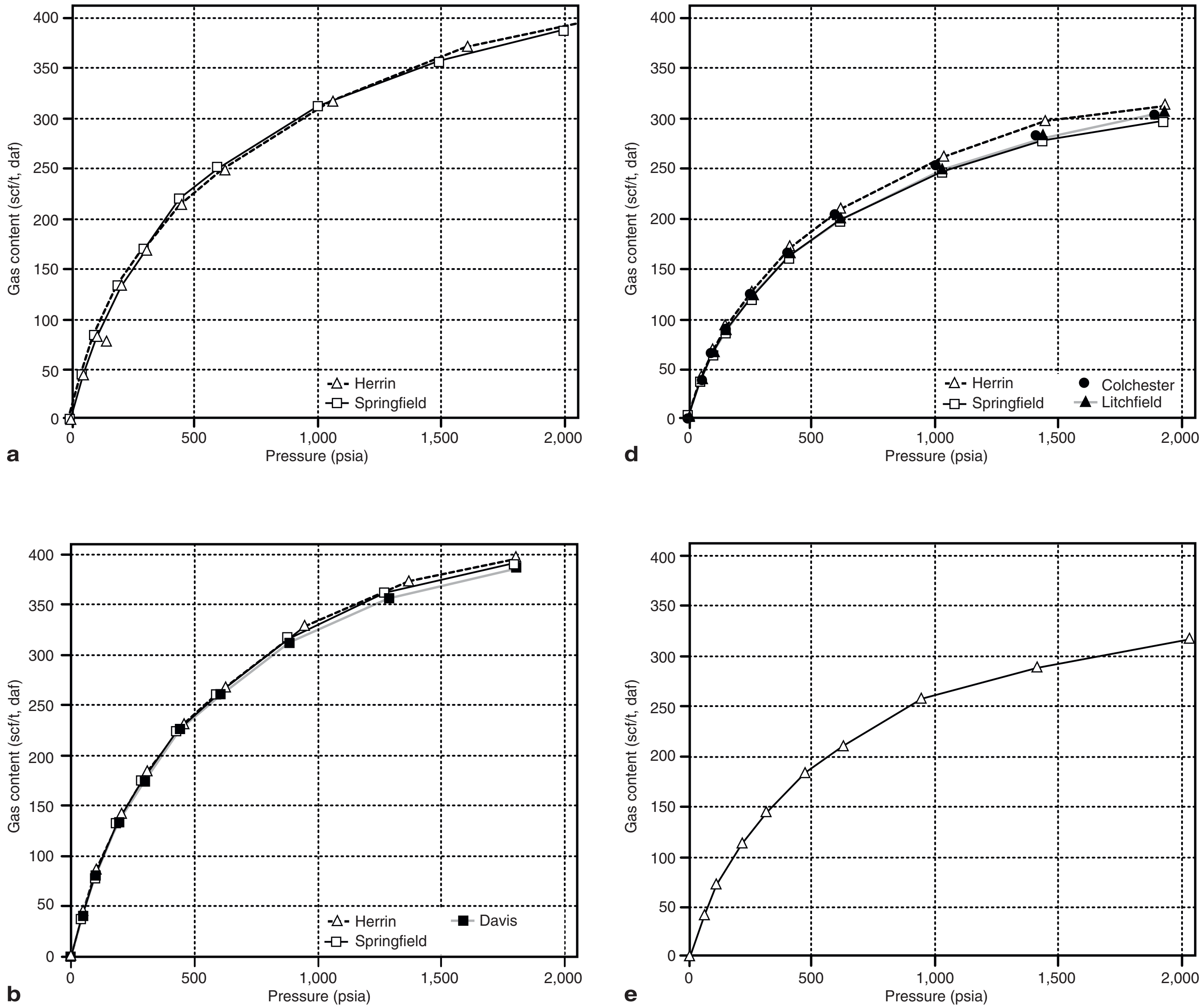
Gas adsorption isotherms along with measured gas contents are used to determine the initial hydrostatic (reservoir) pressure at which CBM can be produced from a coal seam. For example, the lower Seelyville Coal at 820 feet depth in Clark County has an estimated reservoir pressure of 382 psi and a dry, ash-free gas content of 163.6 scf/t at about 70% gas saturation (fig. 27). However, the isotherm shows that the minimum reservoir pressure that can hold the similar amount of gas in place is about 210 psi. Thus, assuming reasonable permeability, the hydrostatic pressure of this coal seam must be reduced to below 210 psi by pumping out the formation water in order to desorb or produce the gas from the seam.

CBM Development Maps

In addition to coal gas content, individual and cumulative coal thicknesses, coal depth, geological structures, coal rank, coal cleat development and orientations, proximity to mined-out areas, and hydrogeological conditions all play a significant role in assessing CBM prospects. Non-geological parameters such as pipeline infrastructure, fuel prices, land and mineral ownership, drilling costs, and environmental regulations must be considered on a case-by-case basis.

Depth is one of the critical factors in CBM exploration. The depth of major coal seams that underlie most of the Illinois coal field increases from the edges to the center of the Basin located in southeastern Illinois (figs. 4, 5, 28, 29, 30). The gas content of a coal seam normally increases with depth because of increasing hydrostatic pressure and coal rank. However, in Illinois, coal rank does not always increase with depth because of tectonic uplift since the Permian period when the maximum burial depth established the ranks. For example, the highest ranks were observed in the southeastern edge of the Illinois coal field (figs. 31, 32) instead of in the deepest area of Fairfield Basin to the north, which is a contradiction to the relatively shallow current depths of the coals in this area. These highest ranks in the south indicate either a minimum burial depth of perhaps 4,500 ft or exposure to southwardly increasing heat flow from plutonic intrusions in the late Paleozoic (Damberger 1971, 1974). Many of the tectonic features (fig. 33) and subsequent erosion formed after maximum burial brought coals of various ranks (high-volatile bituminous C to A) to shallower depths. The La Salle Anticlinal Belt, extending from the Peru Monocline in northern Illinois to the Clay City Anticline in southeastern Illinois, is the most extensive structural feature in the Illinois Basin and is responsible for about 1,250 ft of structural relief in coal-bearing Pennsylvanian formations (Nelson 1991). The La Salle belt separates the Fairfield Basin from a low trough, the Marshal-Sidell Syncline, located on the eastern shelf; western shelves are separated from the Fairfield Basin by the lower relief Du Quoin Monocline and the Salem and Louden Anticlines. We have not evaluated the effects on CBM accumulation and coal permeability of the tectonic folds on the east and west, the Wabash Valley and Cottage Grove Fault Systems on the southeast and south, and Permian ultramafic intrusions associated with Omaha and Hicks Dome on the south of Fairfield Basin. Whether coals that have shale seals and occur on structural highs have high gas content and high permeability or whether coals occurring in structural lows have artesian conditions that encourage secondary biogenic methane generation and entrapment cannot be known without a local systematic study involving drilling, gas content measurements, in situ permeability testing, and geologic and hydrogeological mapping. Detailed reviews of the tectonic history and structures of the Illinois Basin can be found in Nelson (1991) and Kolata and Nelson (1991).

Maps of the mined-out areas (fig. 34) show locations with the potential to produce CMM but not CBM. Virgin seams close to the mined-out areas are expected to lose a substantial amount of their gas into the mine space and are likely not good candidates for CBM production. Some underground mine voids have been shown to contain substantial gas. Initial gas production from a CMM project will likely be high and then will decline to a volume matched by the diffusion rate of gas from coal surfaces in the mine.



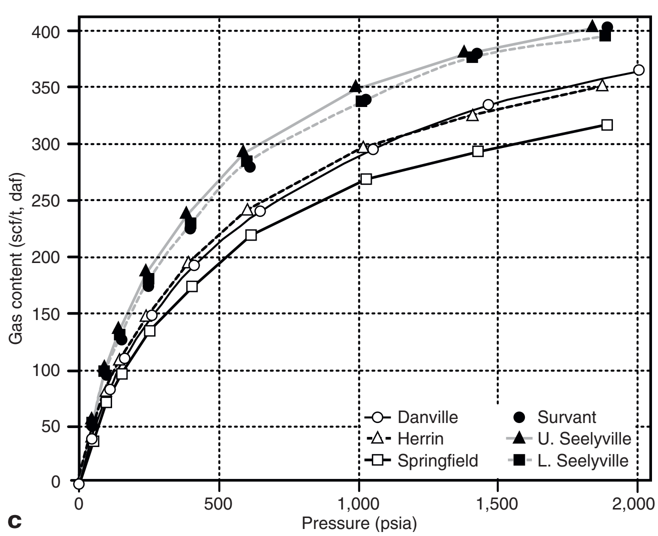


Figure 25 Methane adsorption isotherms of (a) two coal samples from the Richland County well, (b) three coal samples from the Franklin County well, (c) six coal samples from the Clark County well, (d) four coal samples from the Macoupin County well, and (e) one Herrin Coal sample from the Bureau County well. daf, dry, ash free; U., Upper; L., Lower.

Table 10 Gas saturation and related data from methane adsorption isotherms of coal samples from the five ISGS test wells.

County	Coal/ sample no.	Depth (ft)	Estimated geothermal gradient (°F/100 ft)	Mean annual surface temperature (°F)	Calculated reservoir temperature (°F)	Calculated hydrostatic pressure (psi)	Coal gas content (scf/t) dmmf[1]	Coal gas content (scf/t) daf[2]	Langmuir parameters P_L (psia)	Langmuir parameters V_L (scf/t, daf)	Gas storage capacity at reservoir pressure (scf/t, daf)	Gas saturation at reservoir pressure (%)
Richland	Herrin/2	1,045.0	1.8	55.0	74	486	82.6	81.1	584.0	503.0	228.4	36
	Springfield/2	1,110.0	1.8	55.0	75	516	85.3	82.2	527.4	484.8	239.8	34
Franklin	Herrin/1	786.0	1.4	55.9	67	366	144.0	141.4	532.2	512.2	208.6	68
	Springfield/1	849.0	1.4	55.9	68	395	152.5	147.7	531.6	507.7	216.4	68
	Davis/2	1,078.0	1.4	55.9	71	501	105.2	98.3	523.6	496.9	229.8	43
Clark	Danville/1	533.0	1.8	54.0	64	257	63.2	61.9	502.4	447.7	151.4	41
	Herrin	603.8	1.8	54.0	65	281	96.9	95.1	457.7	431.8	164.2	58
	Springfield/1	646.6	1.8	54.0	66	301	92.9	87.4	468.8	391.6	153.0	57
	Survant	741.0	1.8	54.0	67	345	126.7	125.2	435.7	491.3	217.0	58
	U. Seelyville	817.8	1.8	54.0	69	380	134.8	131.8	371.3	480.5	243.1	54
	L. Seelyville/1	821.5	1.8	54.0	69	382	173.2	163.6	390.2	471.5	235.0	70
Macoupin	Herrin/2	361.3	1.8	54.6	61	168	45.5	44.7	518.4	394.9	96.7	46
	Springfield/1	401.6	1.8	54.6	62	187	51.2	48.3	505.2	371.7	100.3	48
	Colchester	457.0	1.8	54.6	63	213	59.7	57.6	470.9	372.8	115.9	50
	Litchfield/2	508.1	1.8	54.6	64	236	83.7	79.6	529.8	382.8	118.1	67
Bureau	Herrin/1	315.3	1.3	53.0	57	147	4.6	4.6	518.5	395.0	87.1	5

[1]dmmf, dry, mineral matter free.
[2]daf, dry, ash free.

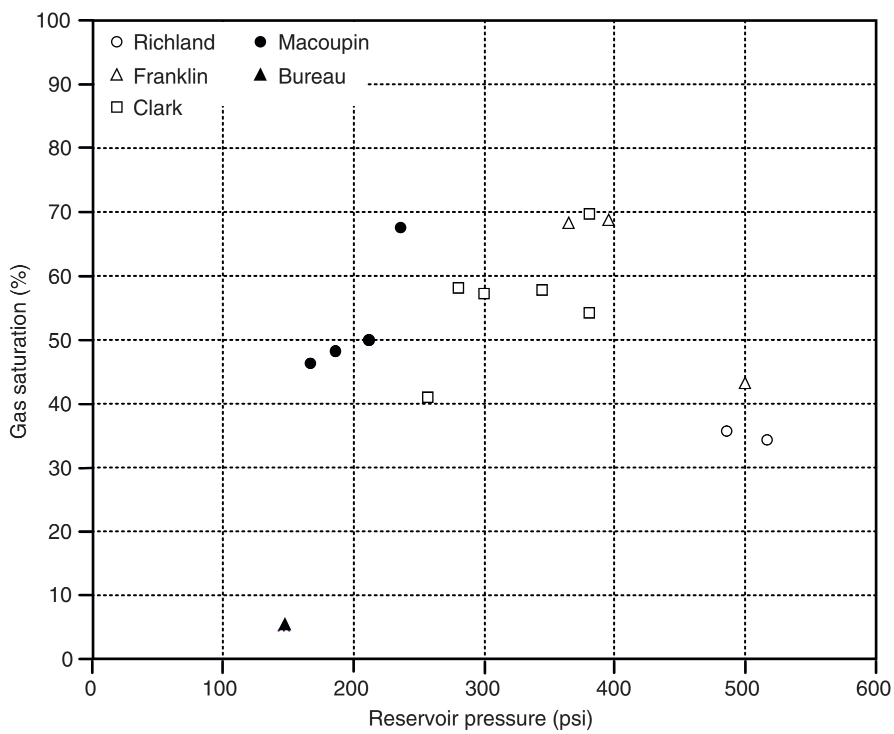


Figure 26 Gas saturation of coal samples from individual wells in five Illinois counties.

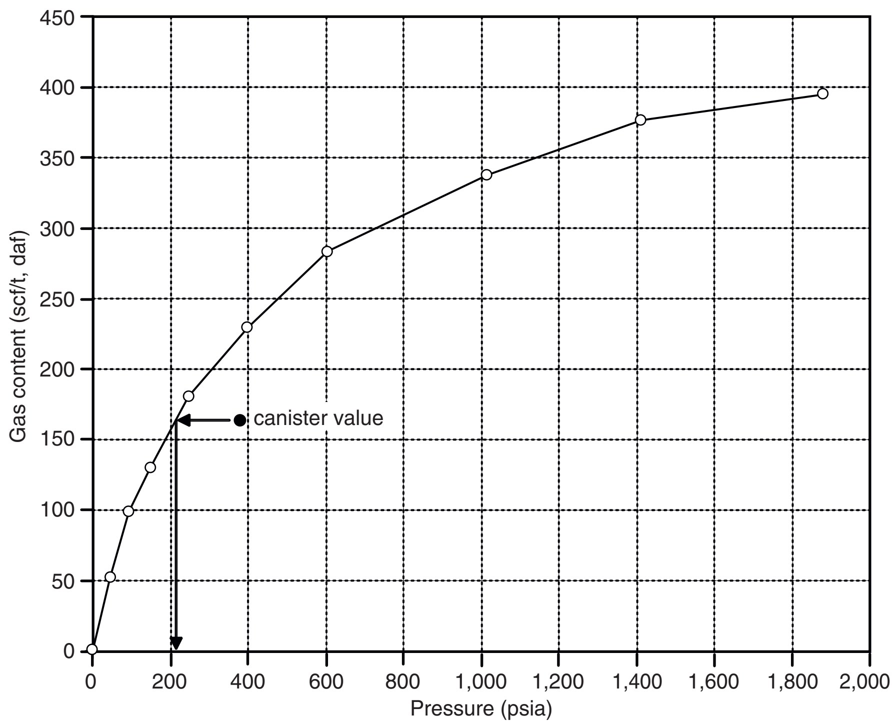


Figure 27 Gas content and methane adsorption isotherm of Lower Seelyville coal from the Clark County well. Pressure would have to drop nearly 200 psi in order to begin desorption of methane from the coal seam.

Maps of the thicknesses of individual coal seams and a cumulative (net) thickness map of all major coal seams (figs. 35 through 43) provide key data for CBM prospecting. Several assumptions were made in creating the cumulative thickness map. First, it is assumed that an individual seam thickness should be greater than 1.5 ft to be used for CBM production; coal seams less than 1.5 ft thick were excluded from the map. Mined-out areas were also excluded from the calculation of the total coal thicknesses. The resulting map shows large areas with 15 to 20 ft of coal, particularly in the southeastern half of the coal field. These net thicknesses can exceed 20 ft in many areas if seams less than 1.5 ft thick are stratigraphically close to other seams so that they all can be completed as a package in a CBM production well. Thus, gas contents, cumulative thicknesses, coal ranks (fig. 43), and coal elevations (figs. 44, 45, and 46) are highly valuable data for determining areas with high CBM reserve potential. The occurrence of organic-rich black shales in coal-bearing sections increases the CBM potential because these organic-rich shales can be sources of additional gas.

Coal permeability and reservoir pressure are key parameters for extracting gas from areas with high CBM reserve potential. Coal permeability, in turn, is highly dependent on coal cleat development and orientation; these factors determine the direction of gas flow during CBM production and the best orientation for horizontal wells. Limited data indicate that the orthogonal cleat orientations are generally northwest to southeast and northeast to southwest (figs. 47, 48). The contemporary in situ stress field and mineralization affect the cleat widths and thus coal permeability. Available data from southern Illinois suggest that the contemporary maximum compressive stress field is likely in east-west to east-northeast to west-southwest directions (Nelson and Bauer 1987). In areas where face cleats are perpendicular to these in situ stress directions, permeability is reduced because of closed or reduced cleat widths. A study by Cobb (1981) and unpublished observations by other ISGS scientists indicate that pyrite, sphalerite, calcite, kaolinite, and barite growth may occur in some cleats of Illinois coals, especially along the basin margins. Therefore, the determination of field permeability and hydrodynamic parameters should supplement cleat orientation and frequency data to obtain a better understanding of gas flow directions and efficiency in CBM wells. The permeability determination requires conducting in situ step-rate or pressure fall-off tests; coal cores are too damaged by drilling to provide reliable permeability values.

Potentiometric surface and hydrochemistry maps and numerical groundwater modeling can delineate the hydrodynamics or groundwater flow patterns (Kaiser et al. 1991, Scott et al. 1994, Scott 2002) that are important for CBM production.

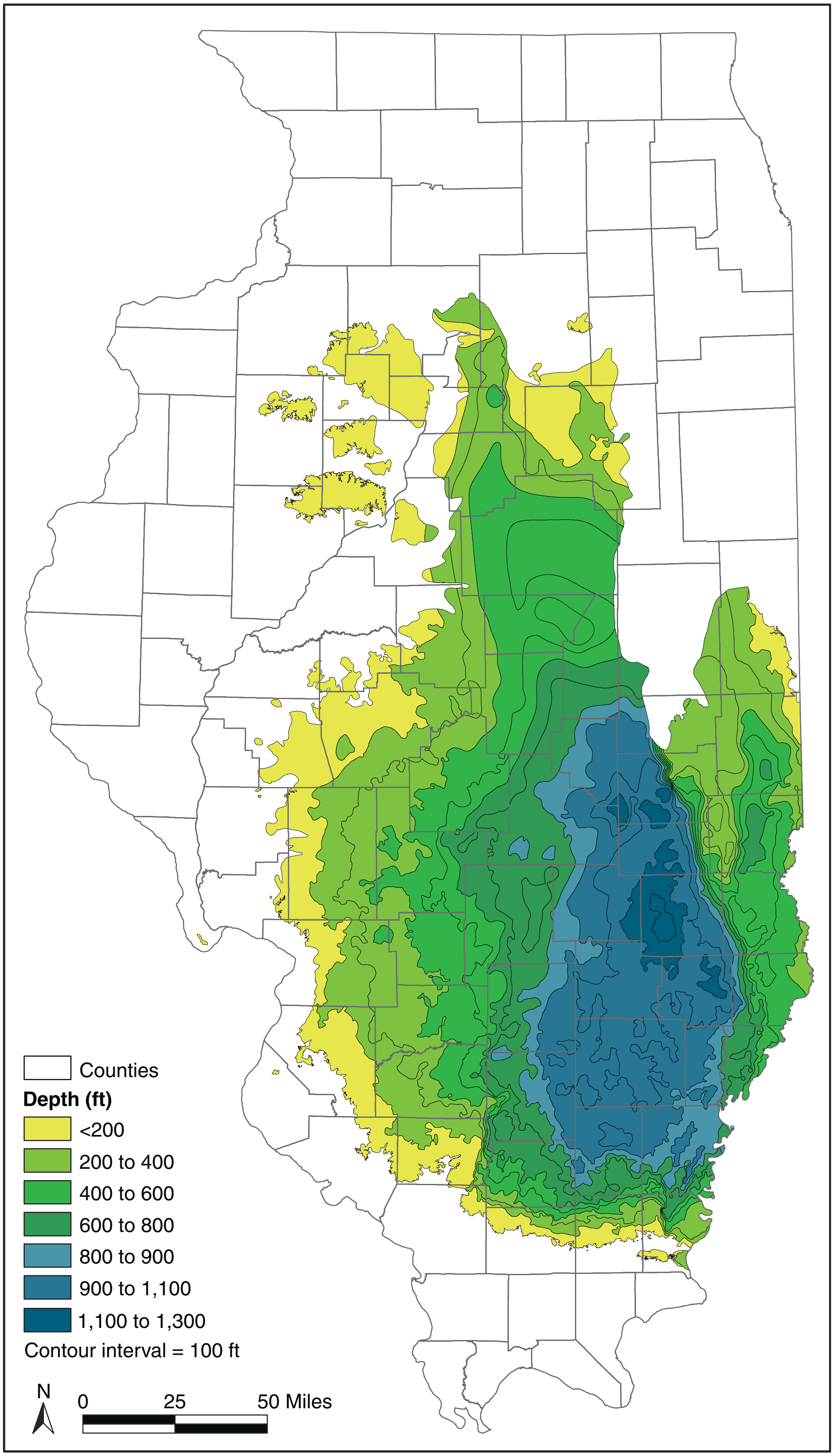


Figure 28 Herrin (No. 6) Coal depth.

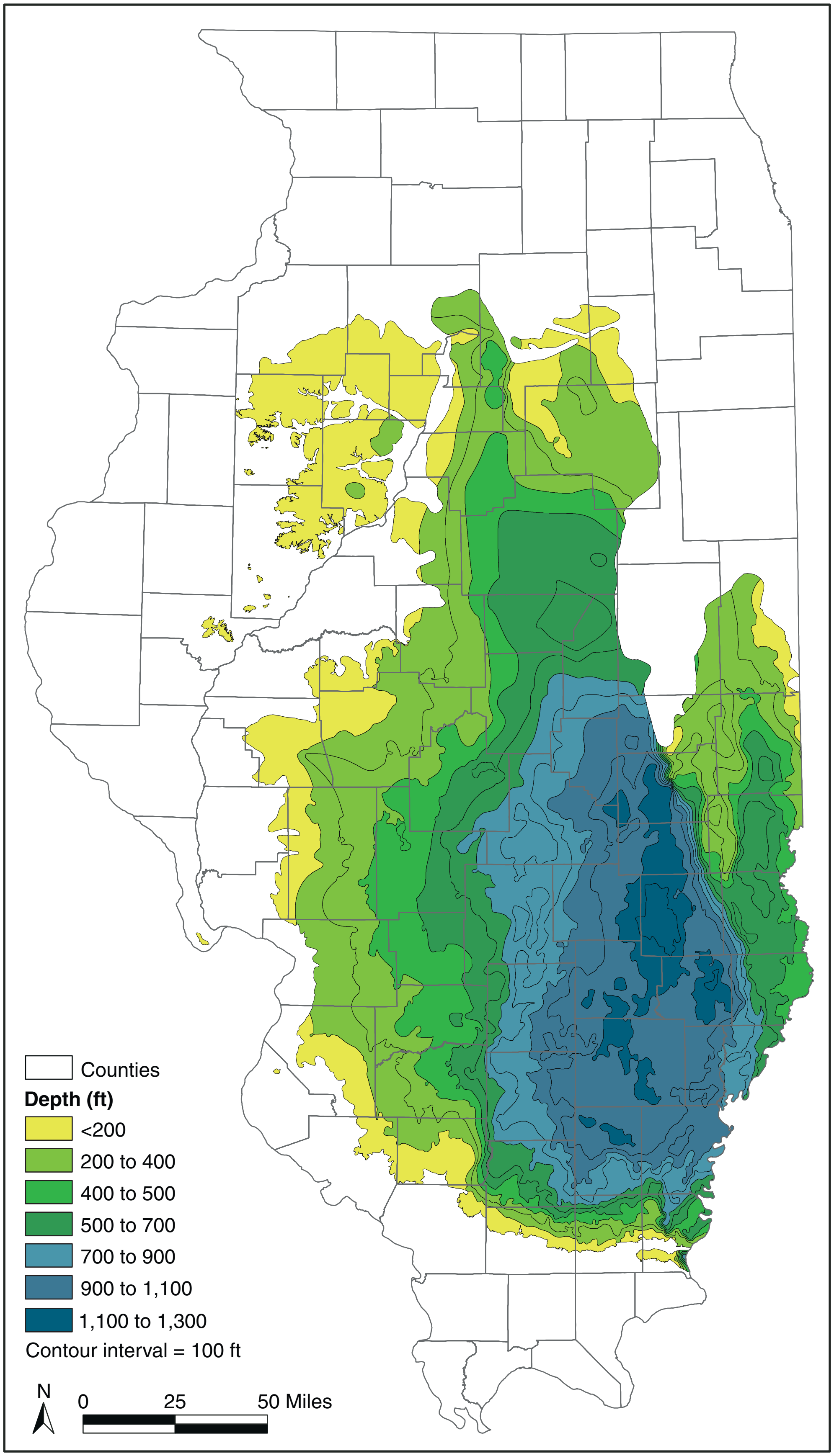


Figure 29 Springfield (No. 5) Coal depth.

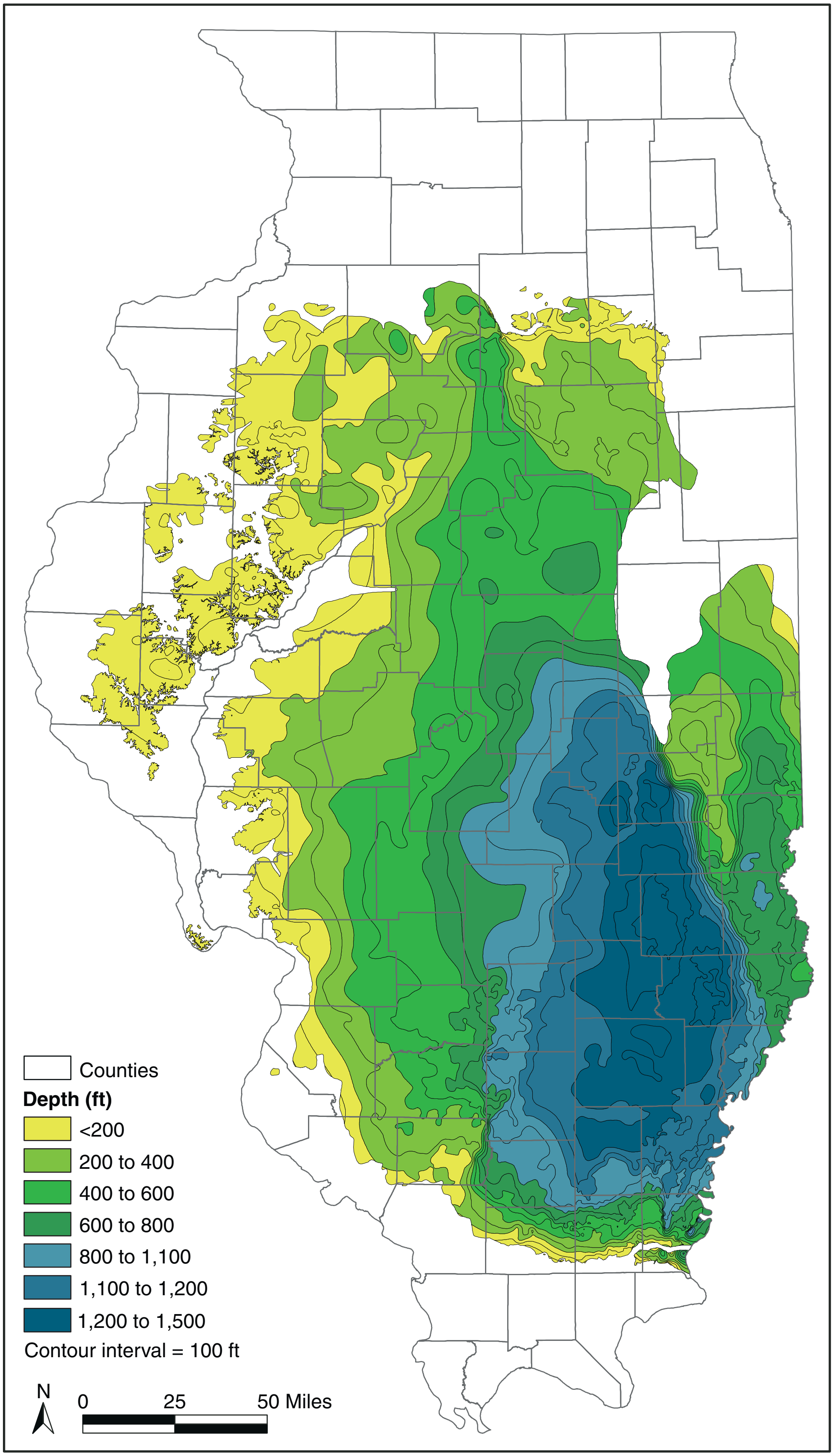


Figure 30 Colchester (No. 2) Coal depth.

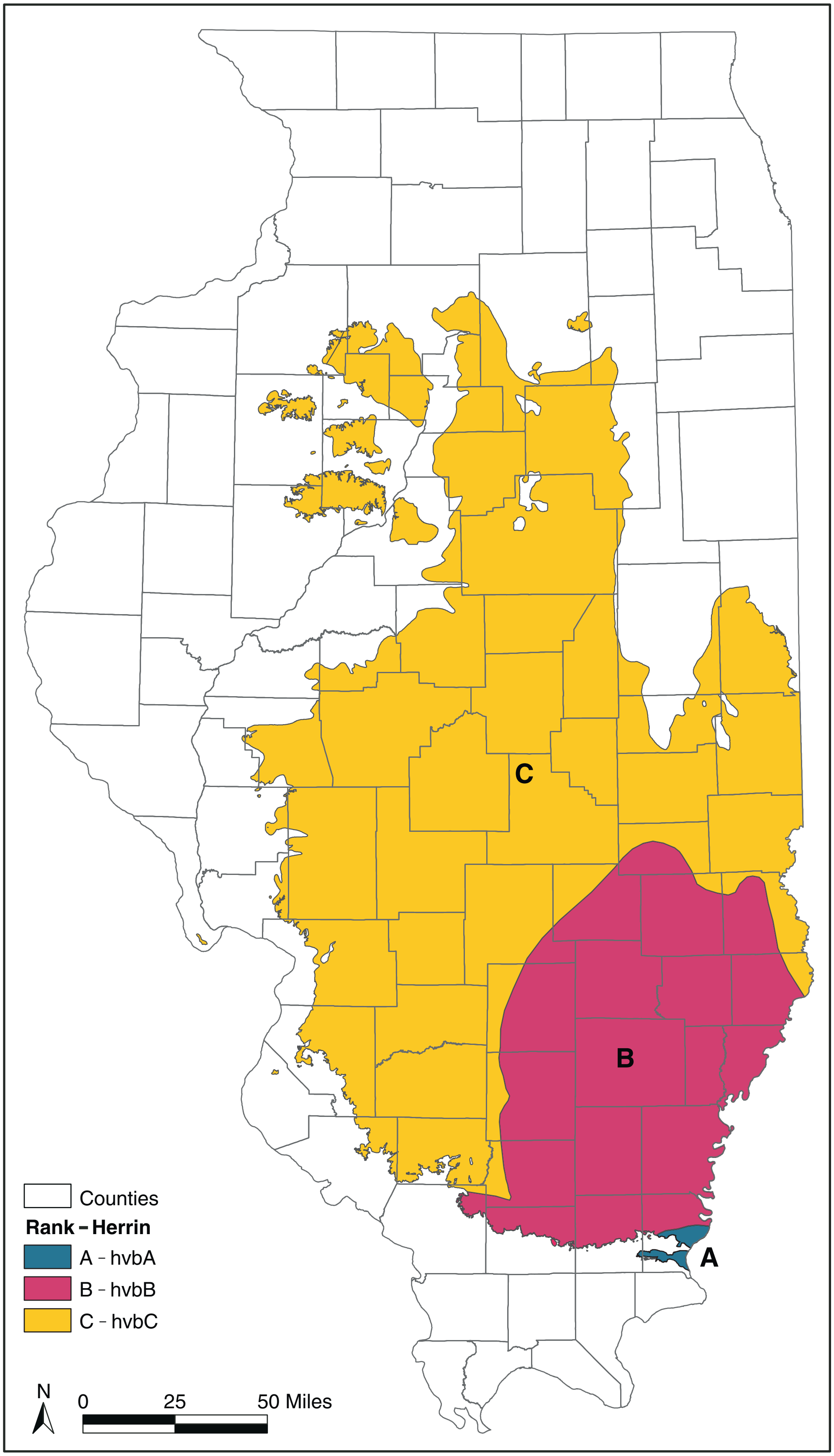


Figure 31 Herrin (No. 6) Coal rank.

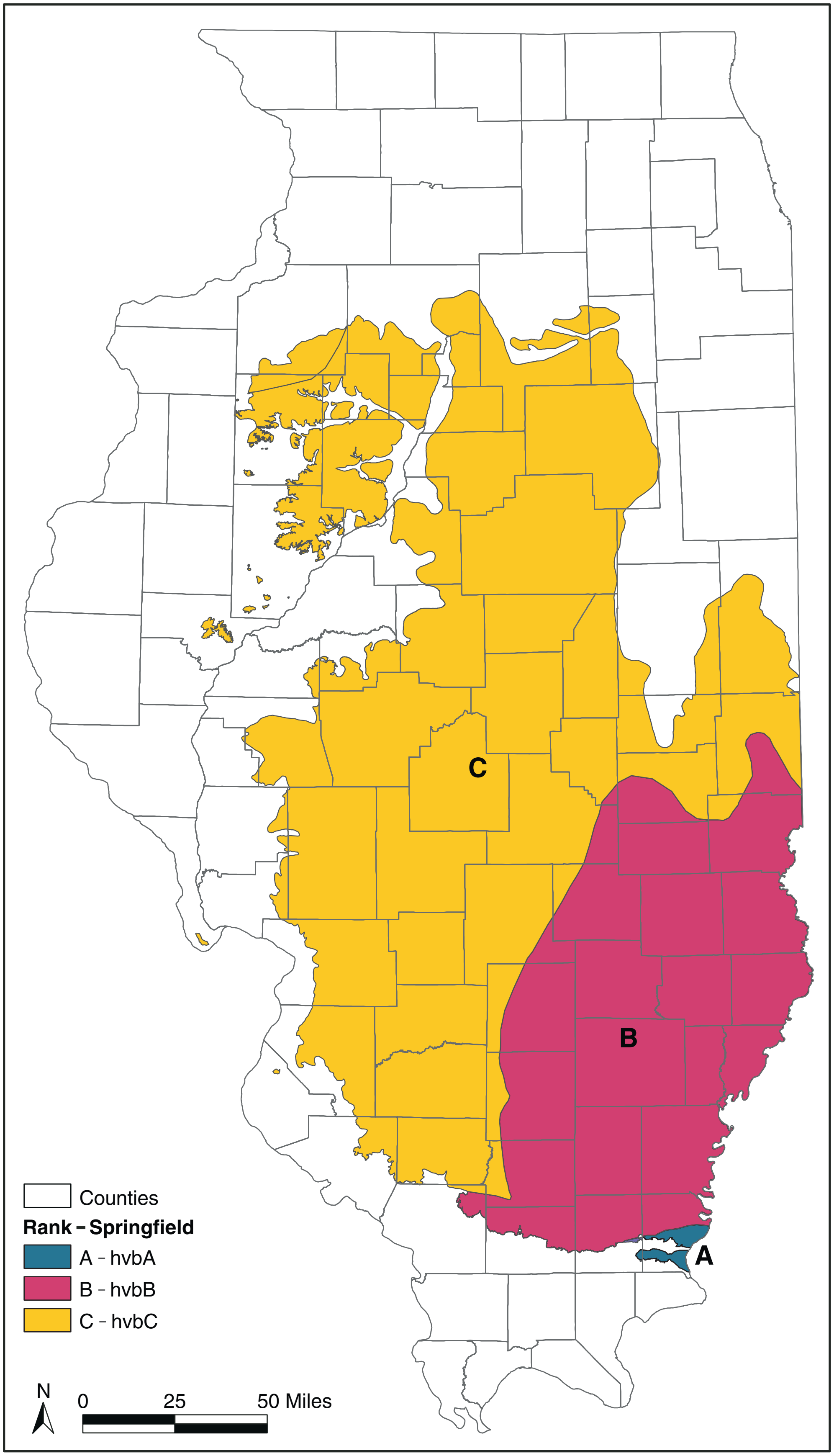


Figure 32 Springfield (No. 5) Coal rank.

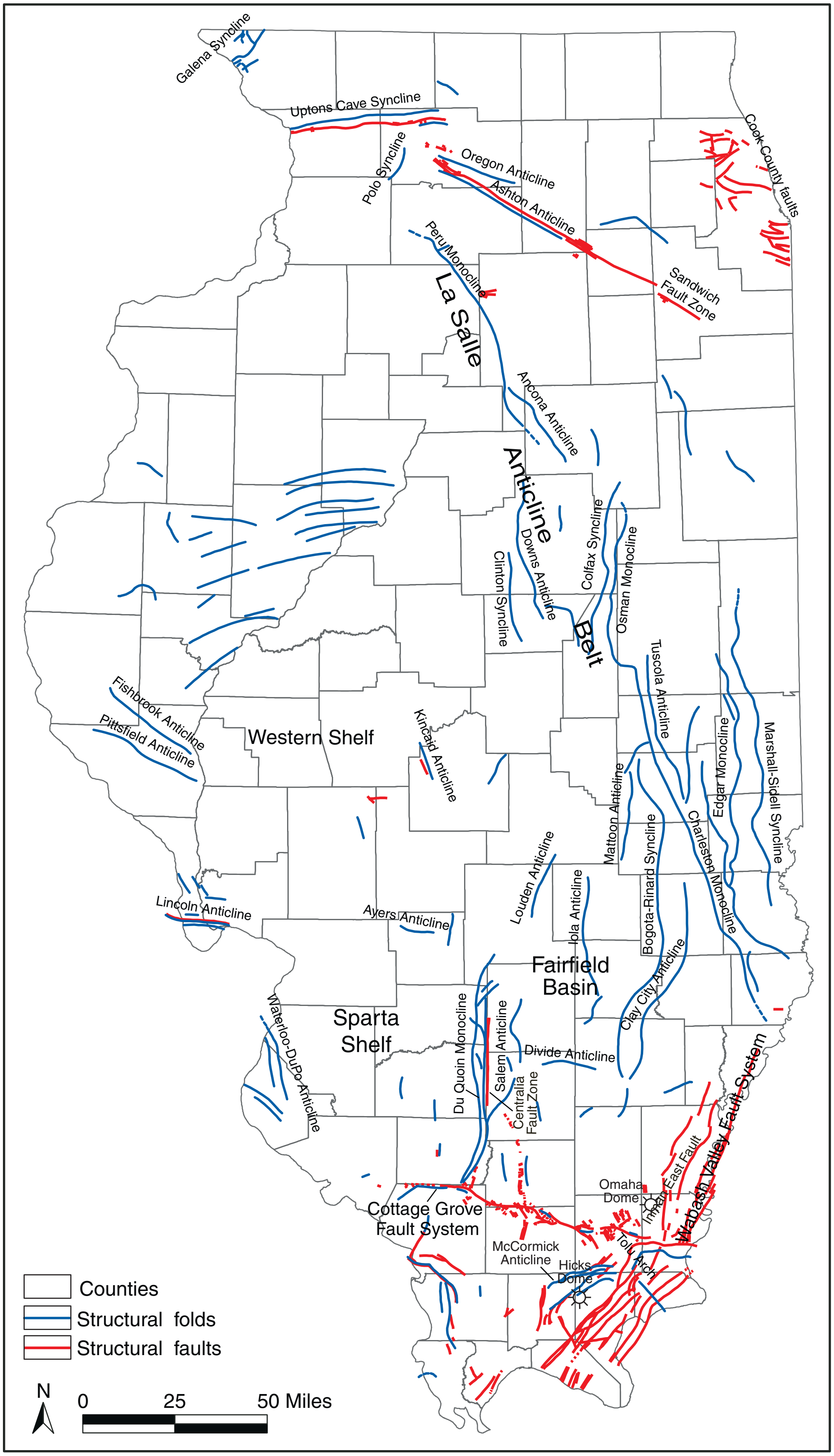


Figure 33 Tectonic features of Illinois (modified from Treworgy et al. 1997).

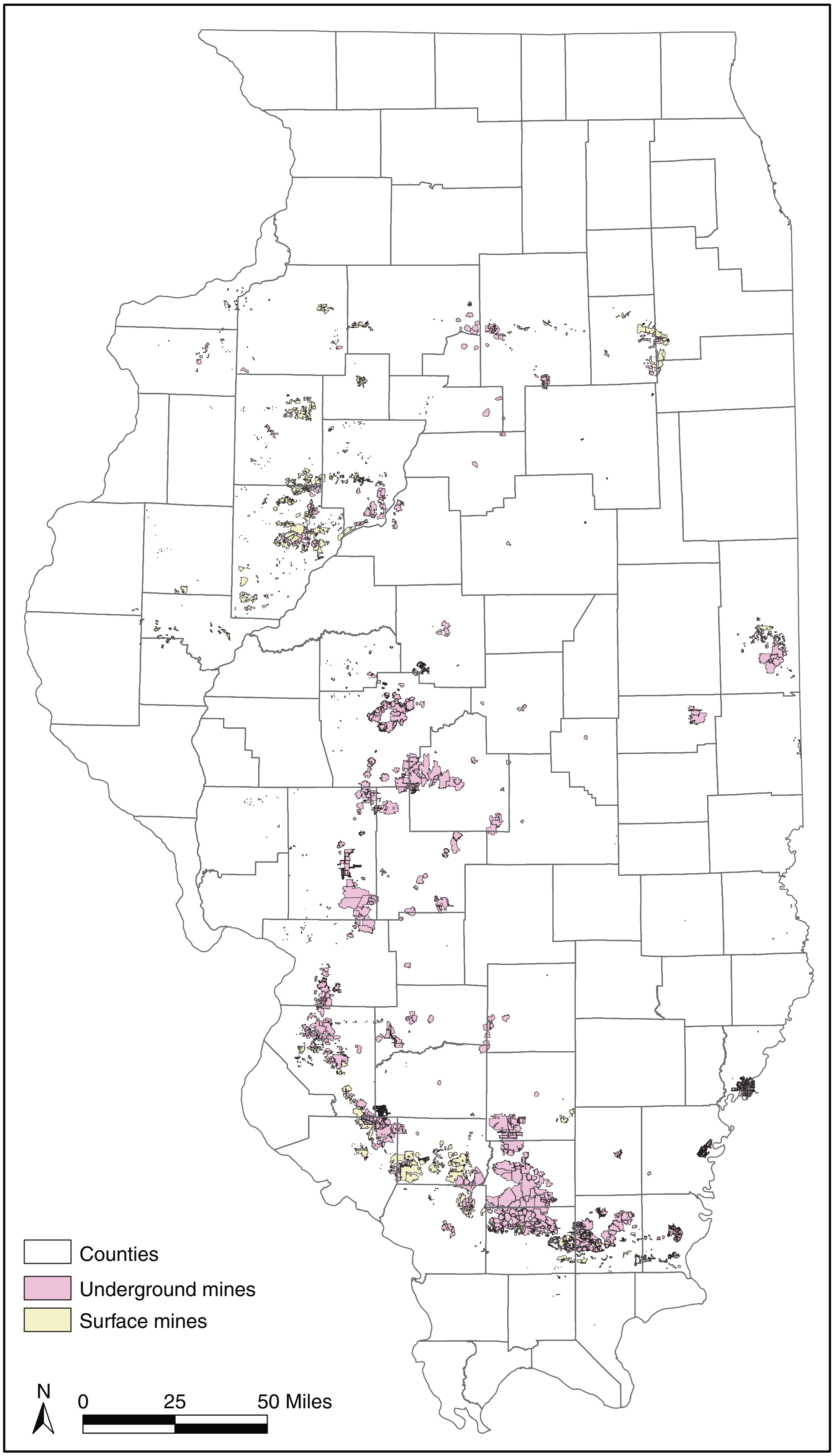


Figure 34 Mined-out areas in Illinois.

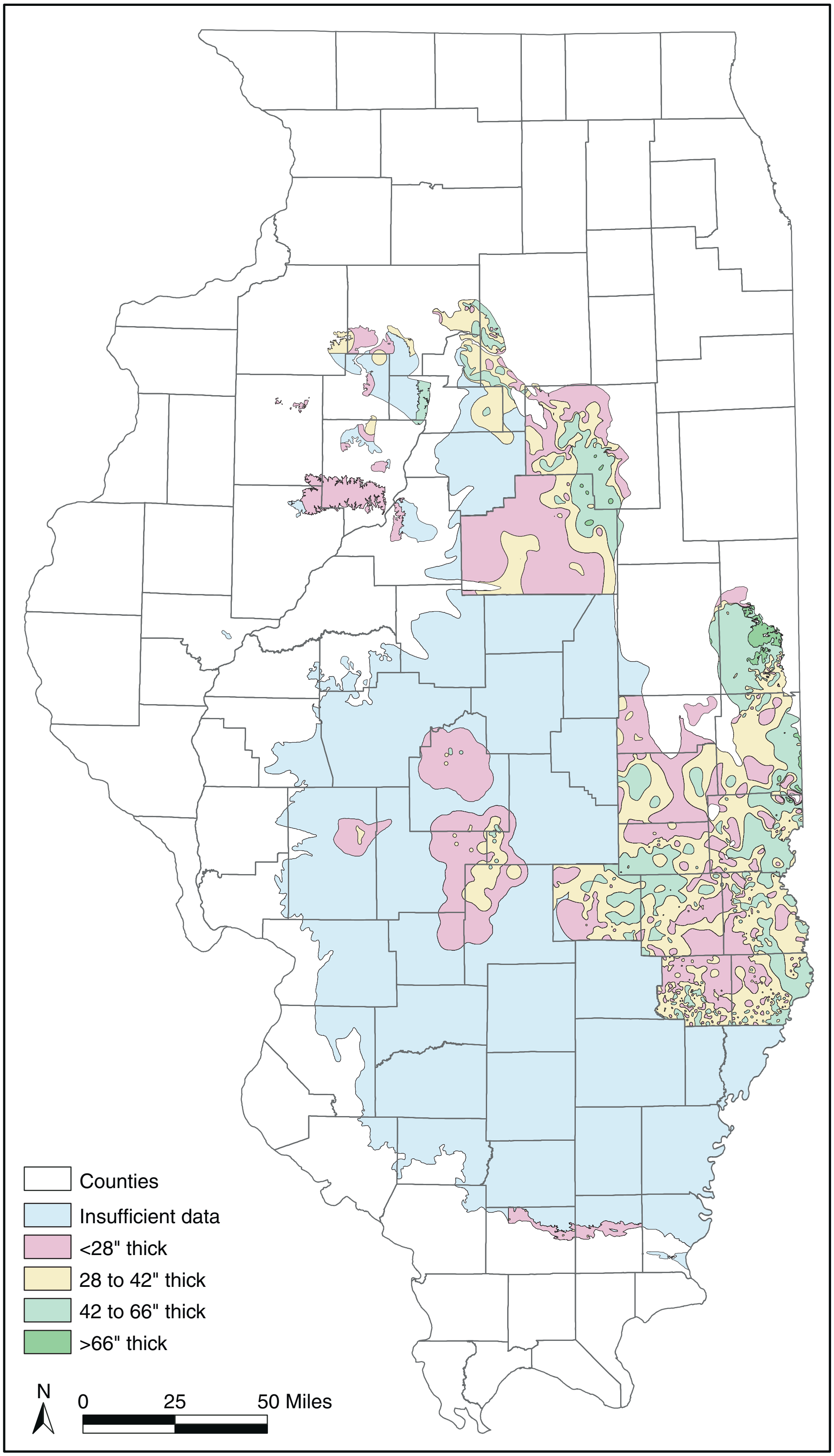


Figure 35 Danville (No. 7) Coal thickness.

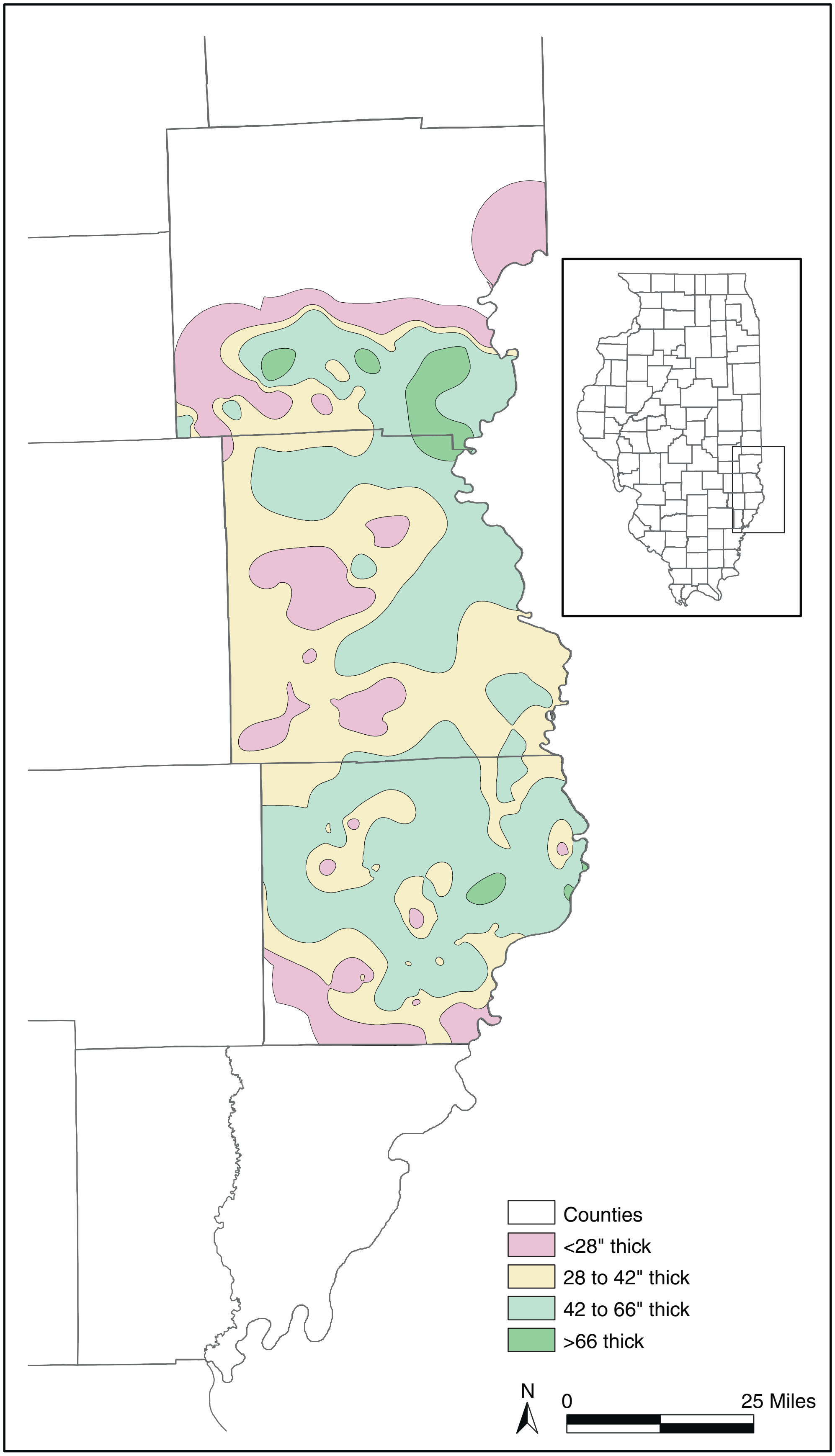


Figure 36 Jamestown Coal thickness.

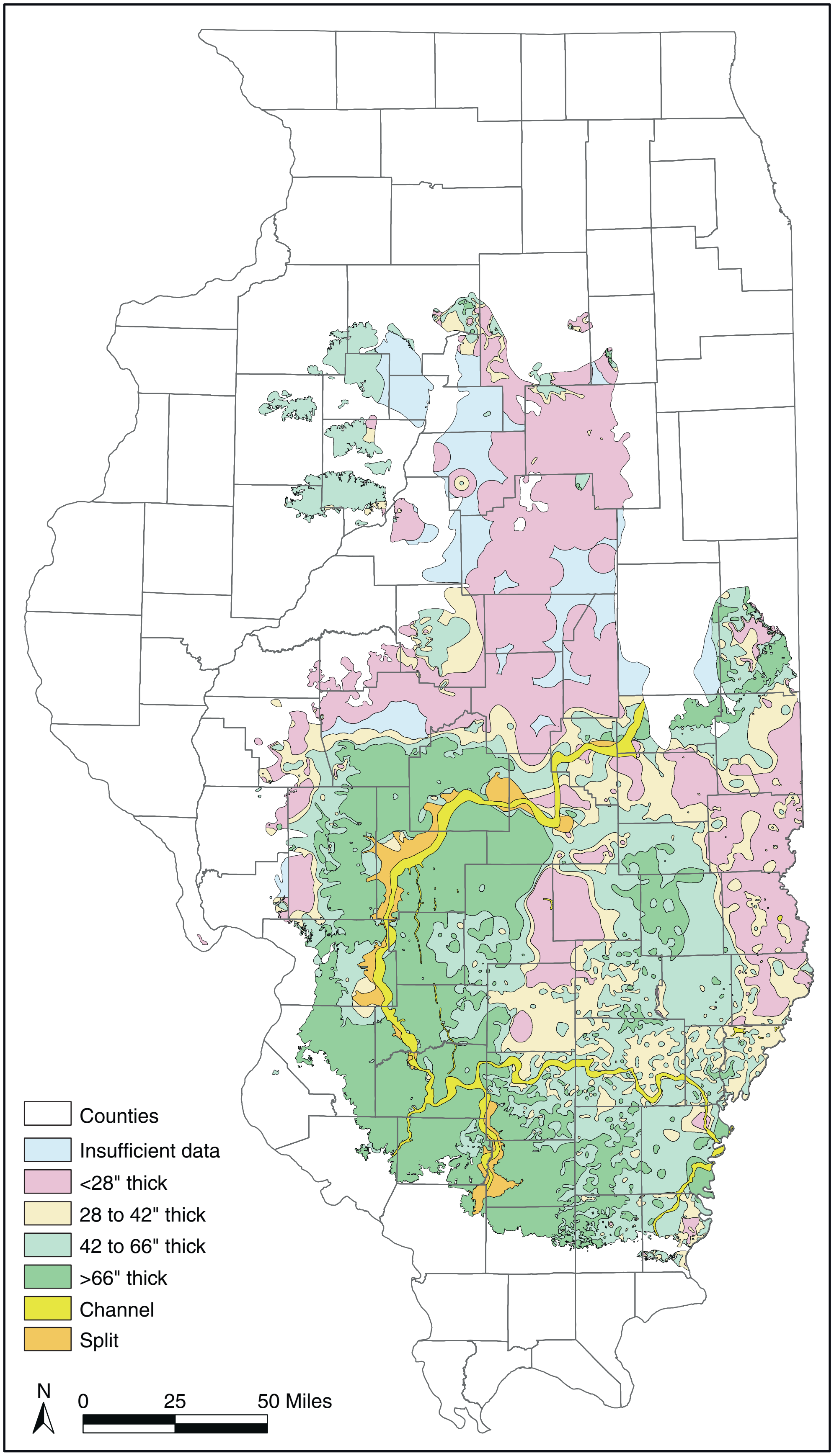


Figure 37 Herrin (No. 6) Coal thickness.

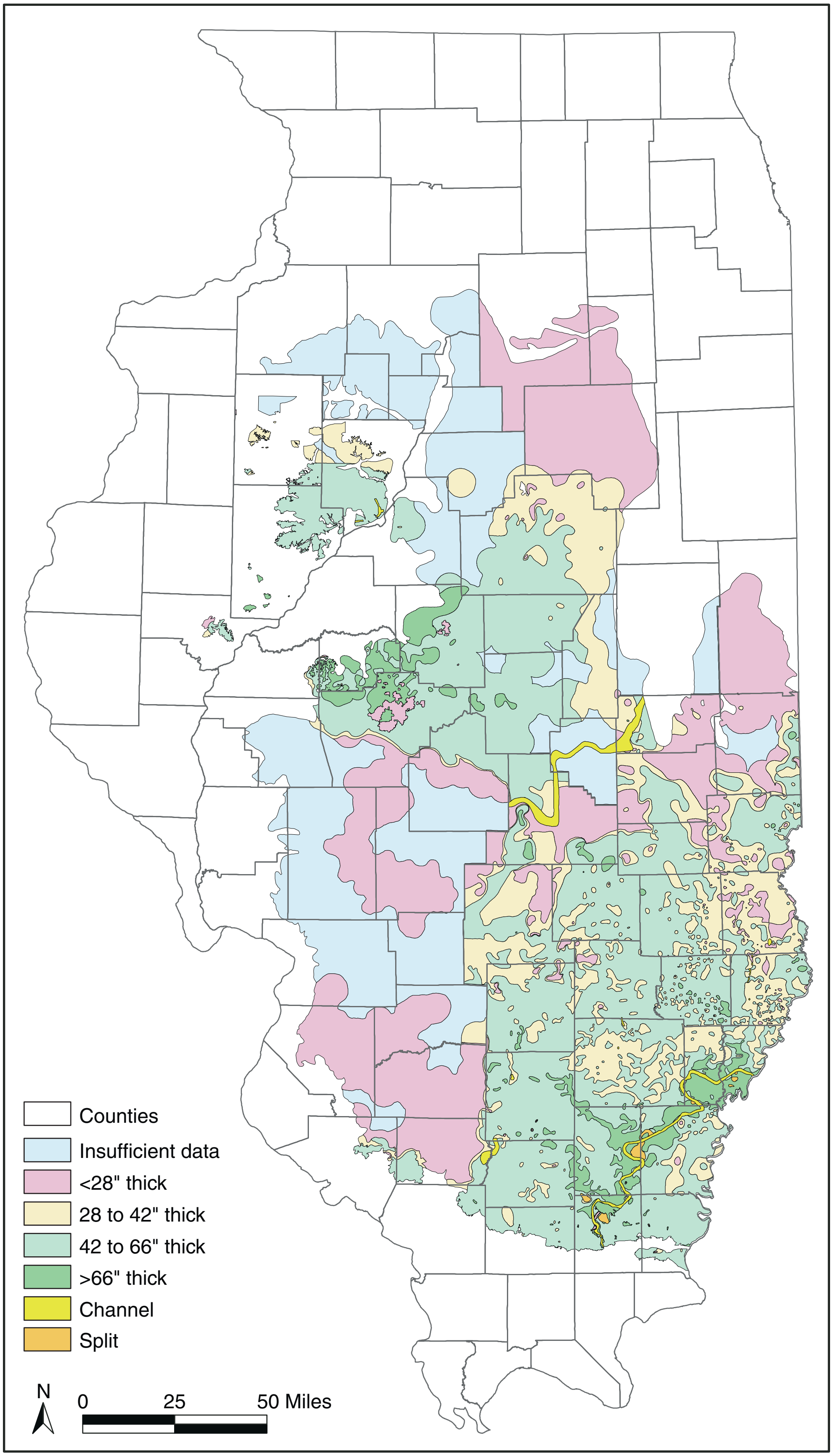


Figure 38 Springfield (No. 5) Coal thickness.

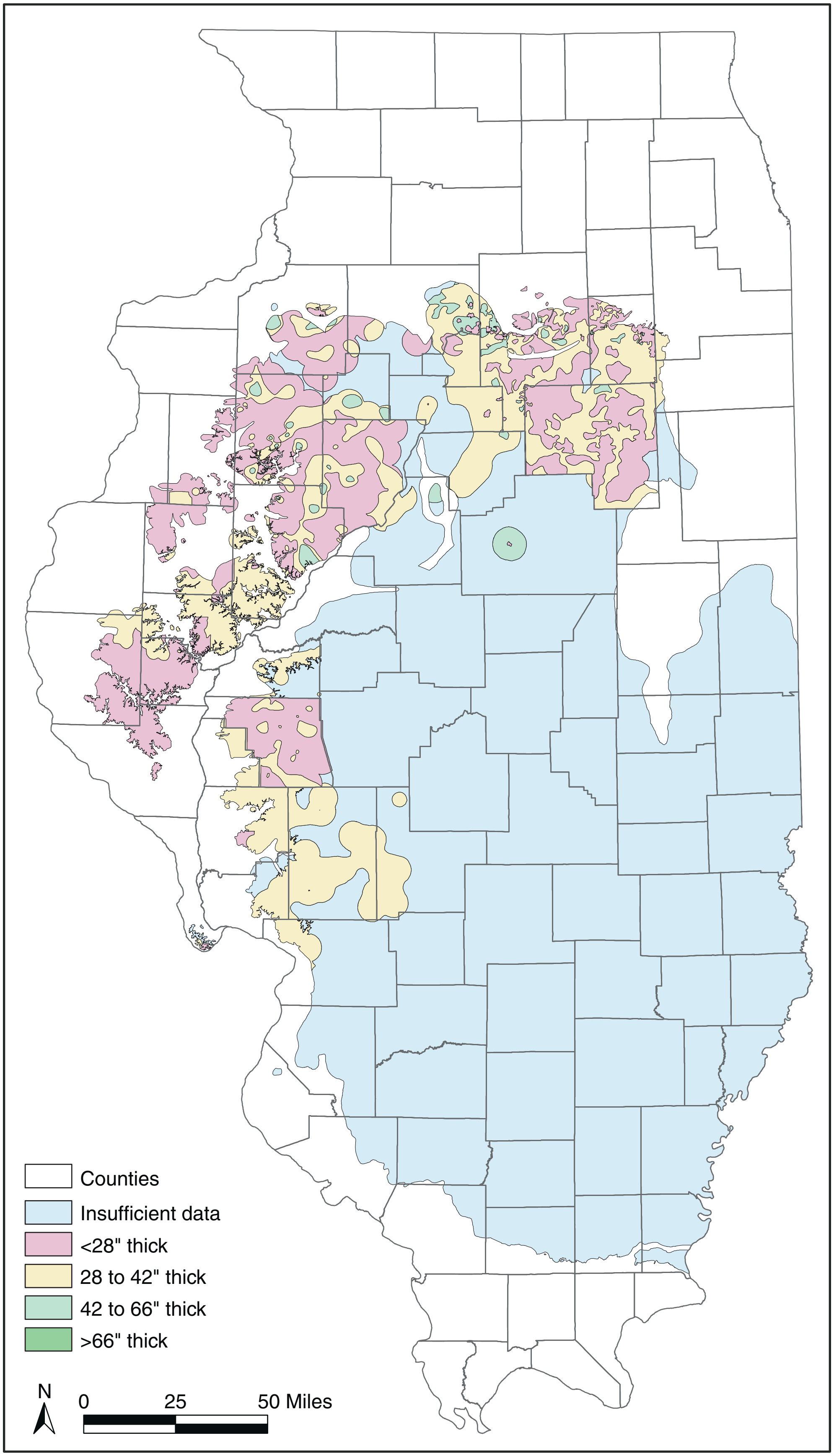


Figure 39 Colchester (No. 2) Coal thickness.

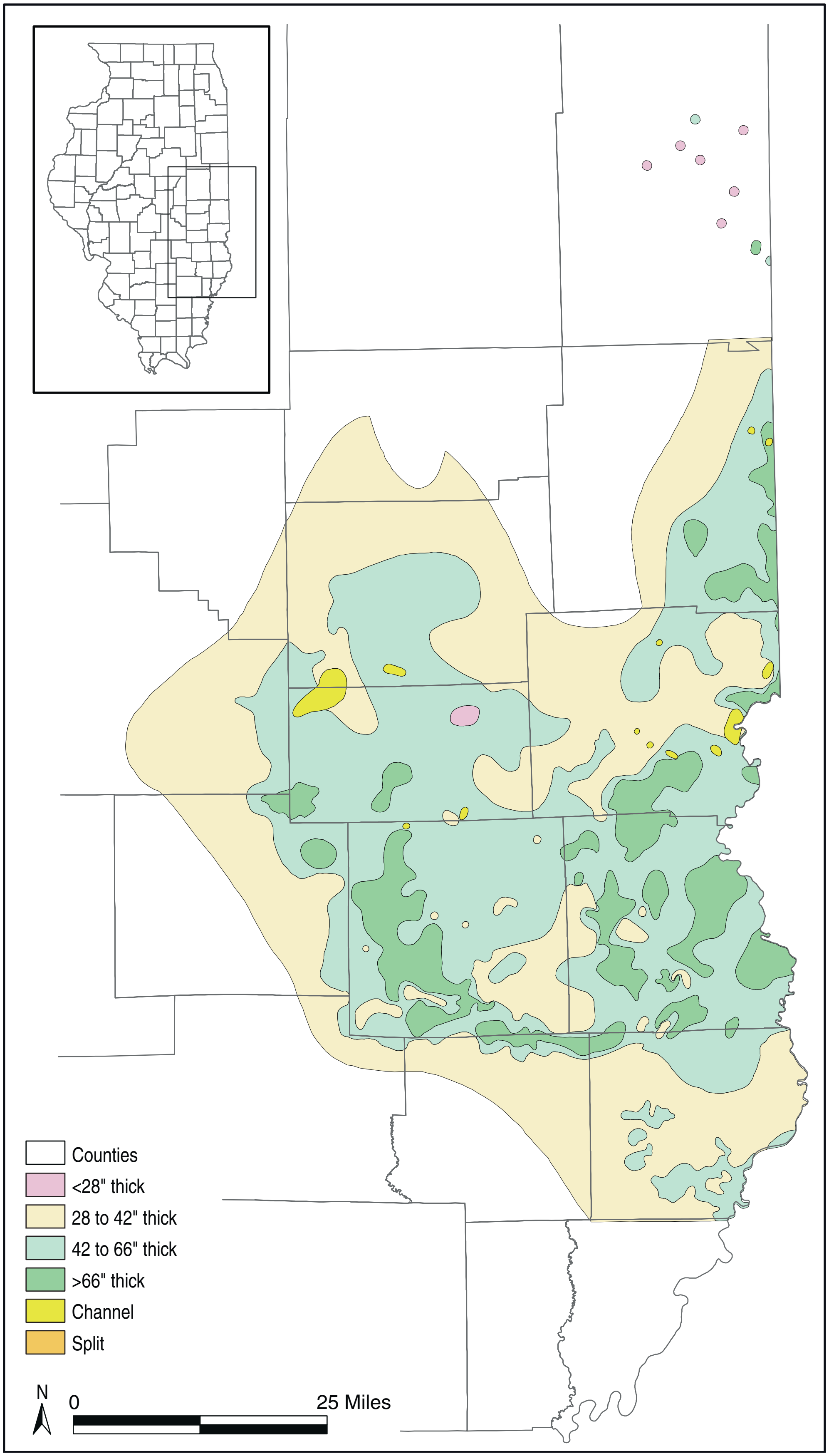


Figure 40 Seelyville Coal thickness.

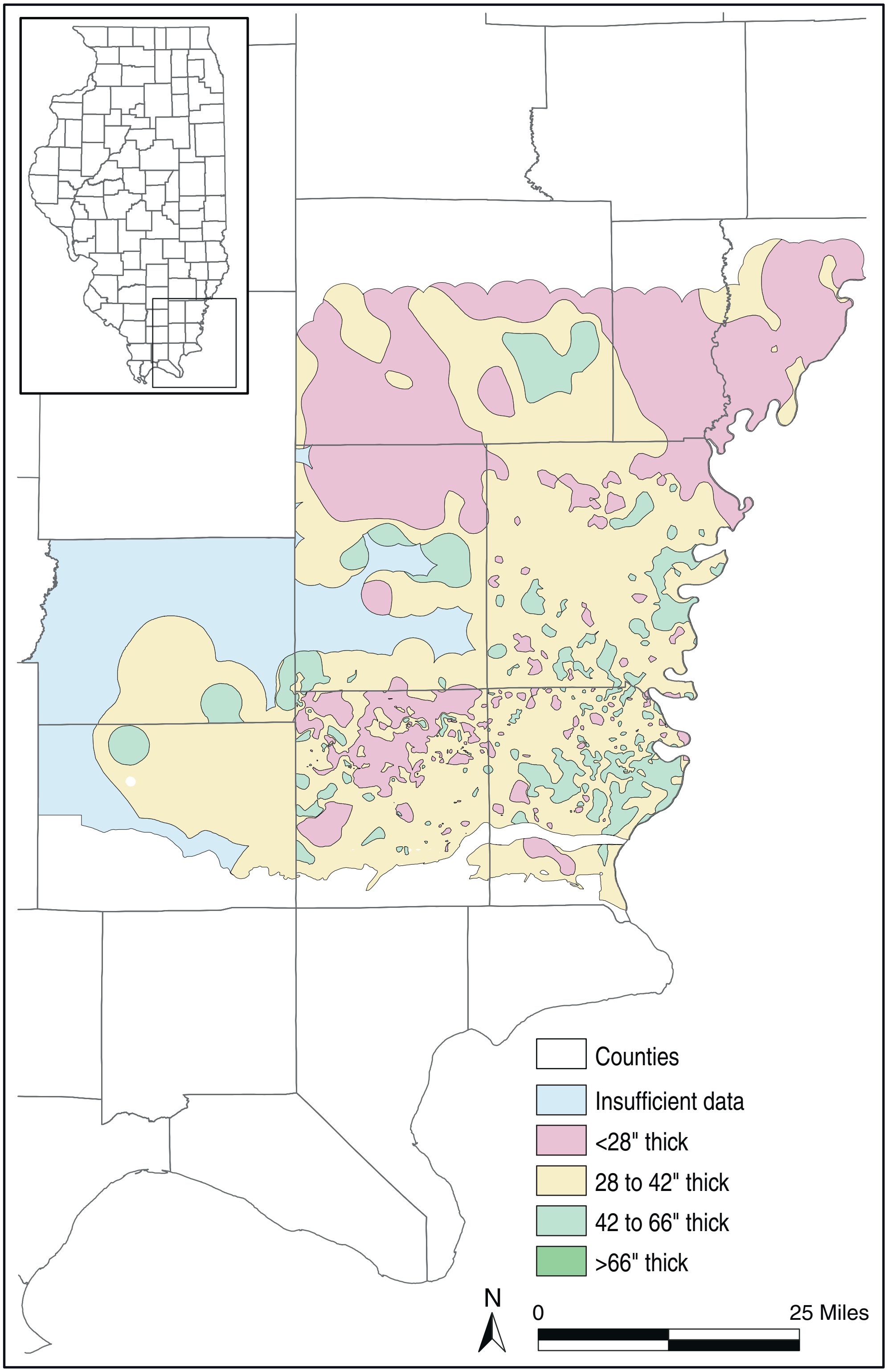


Figure 41 Dekoven Coal thickness.

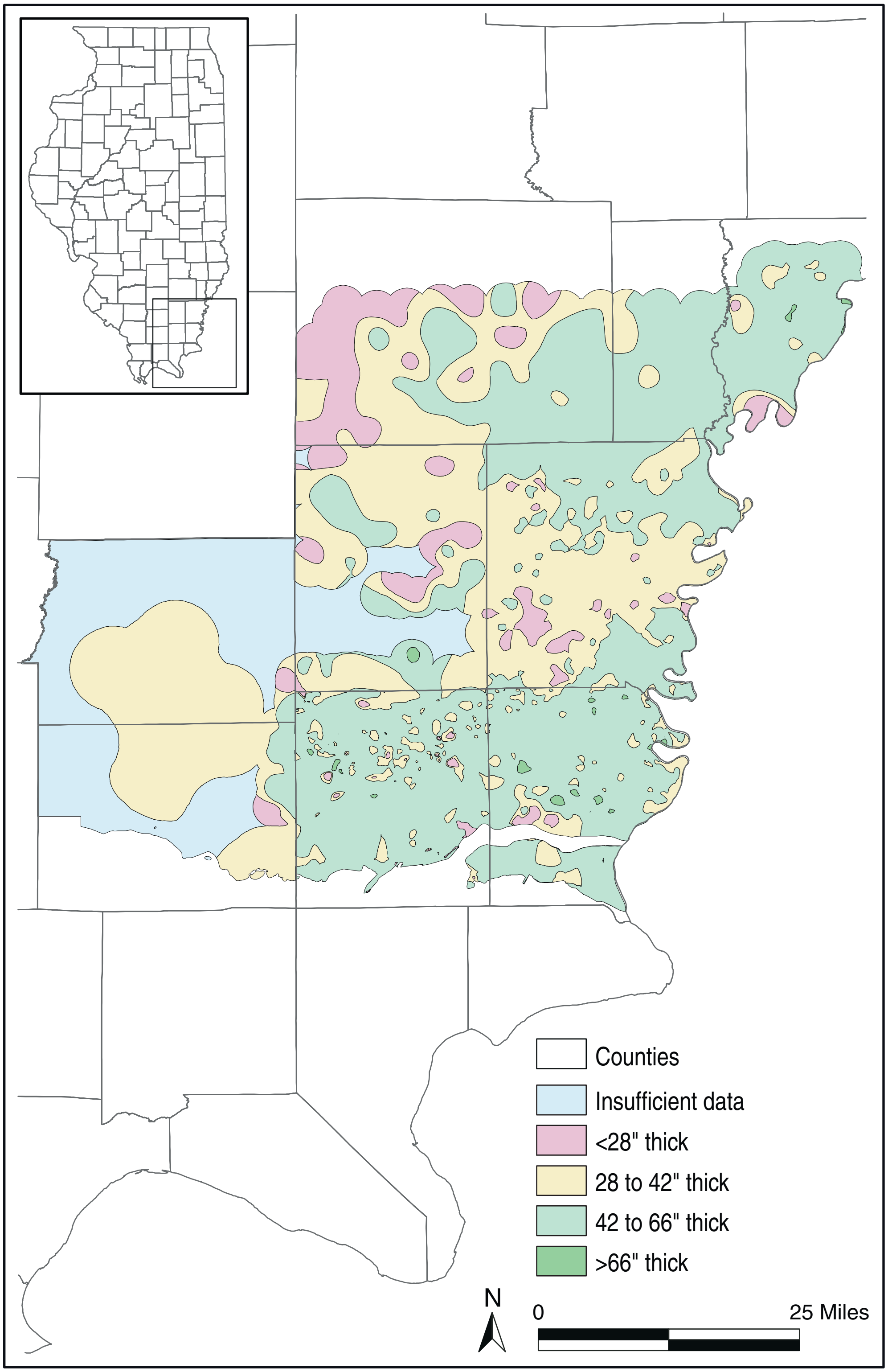


Figure 42 Davis Coal thickness.

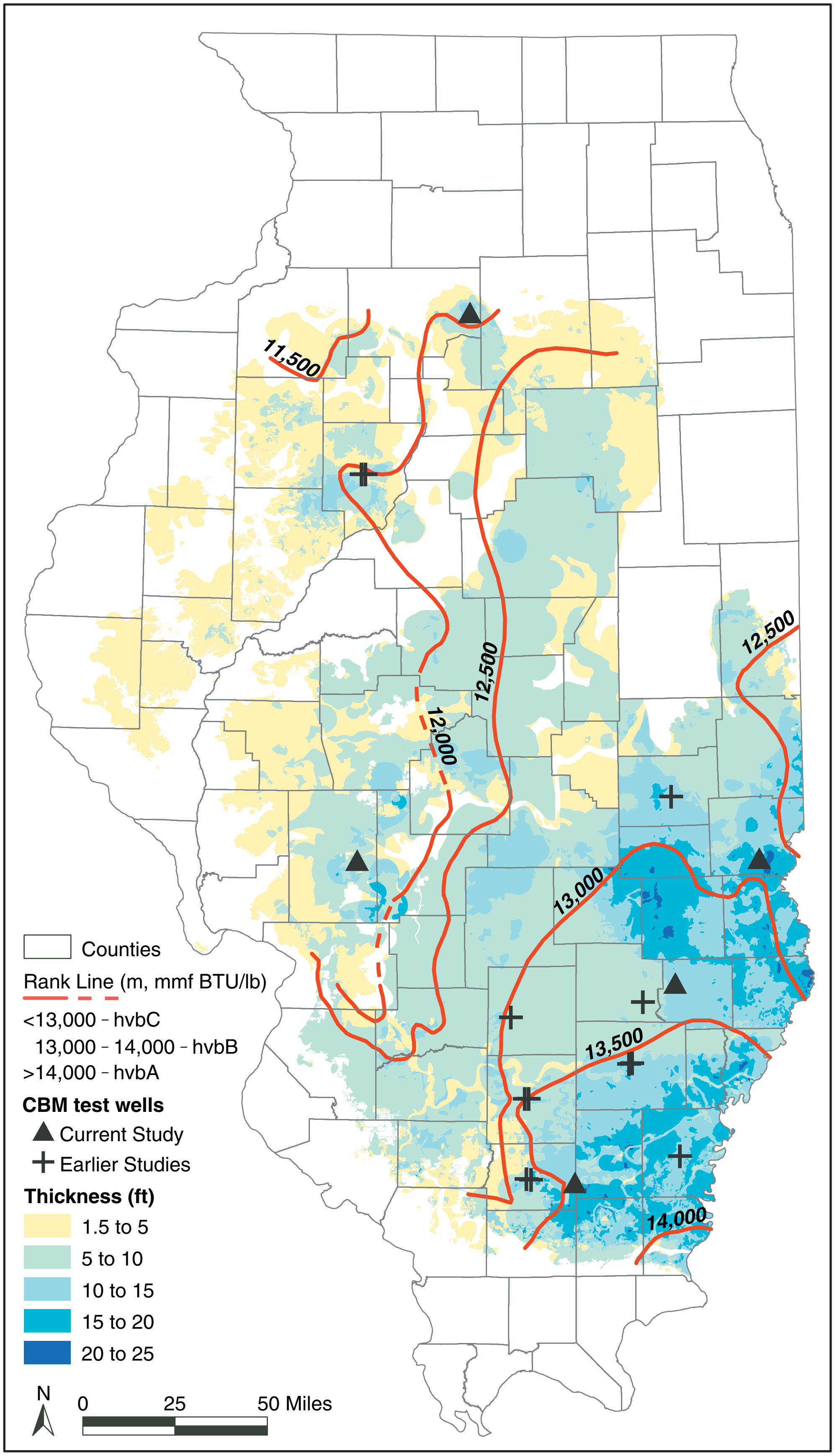


Figure 43 Cumulative thickness of coal remaining in Illinois and rank lines of the Herrin (No. 6) Coal. Seams <1.5 ft excluded. mmf, mineral matter free.

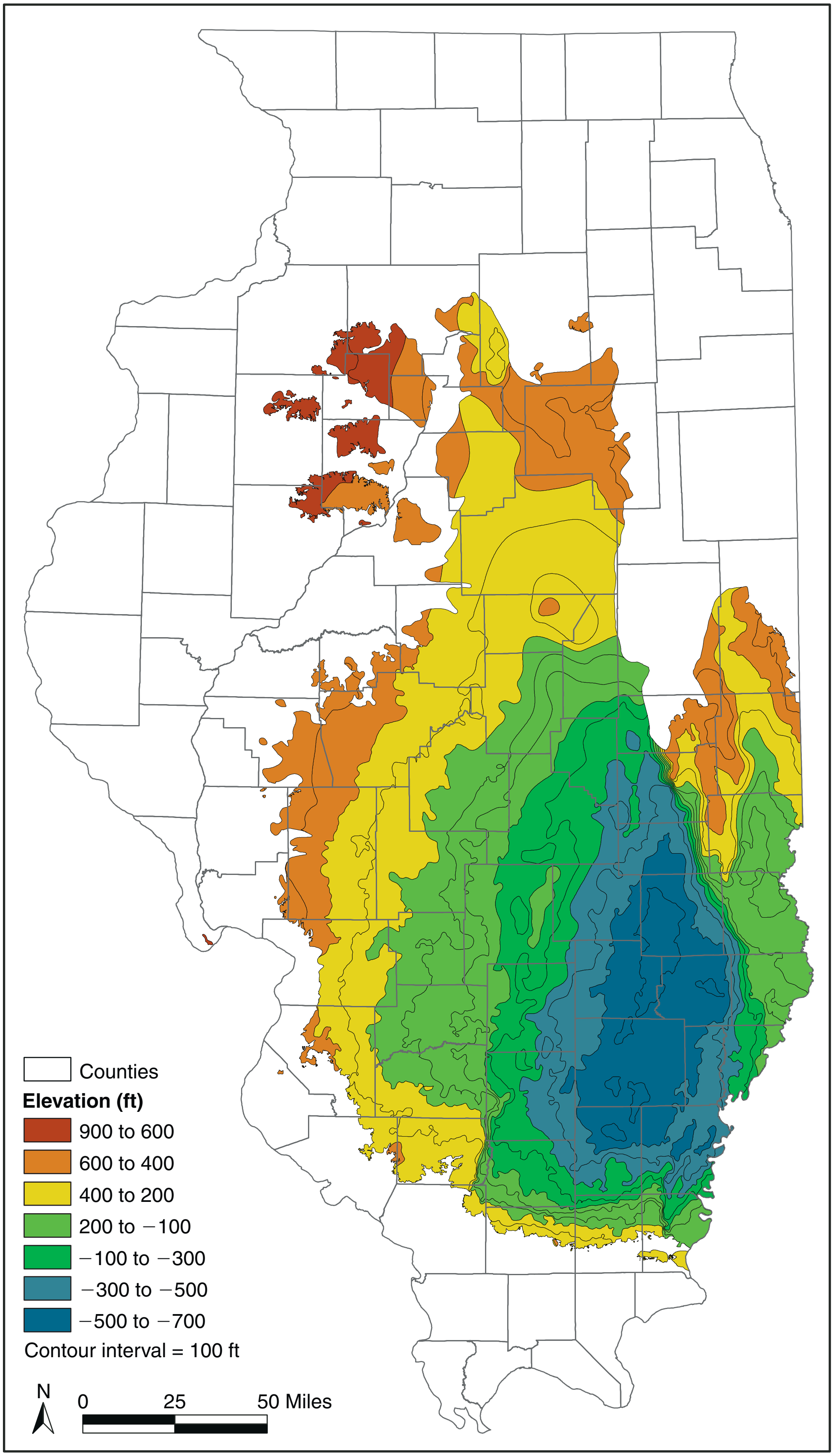


Figure 44 Herrin (No. 6) Coal elevation with respect to mean sea level.

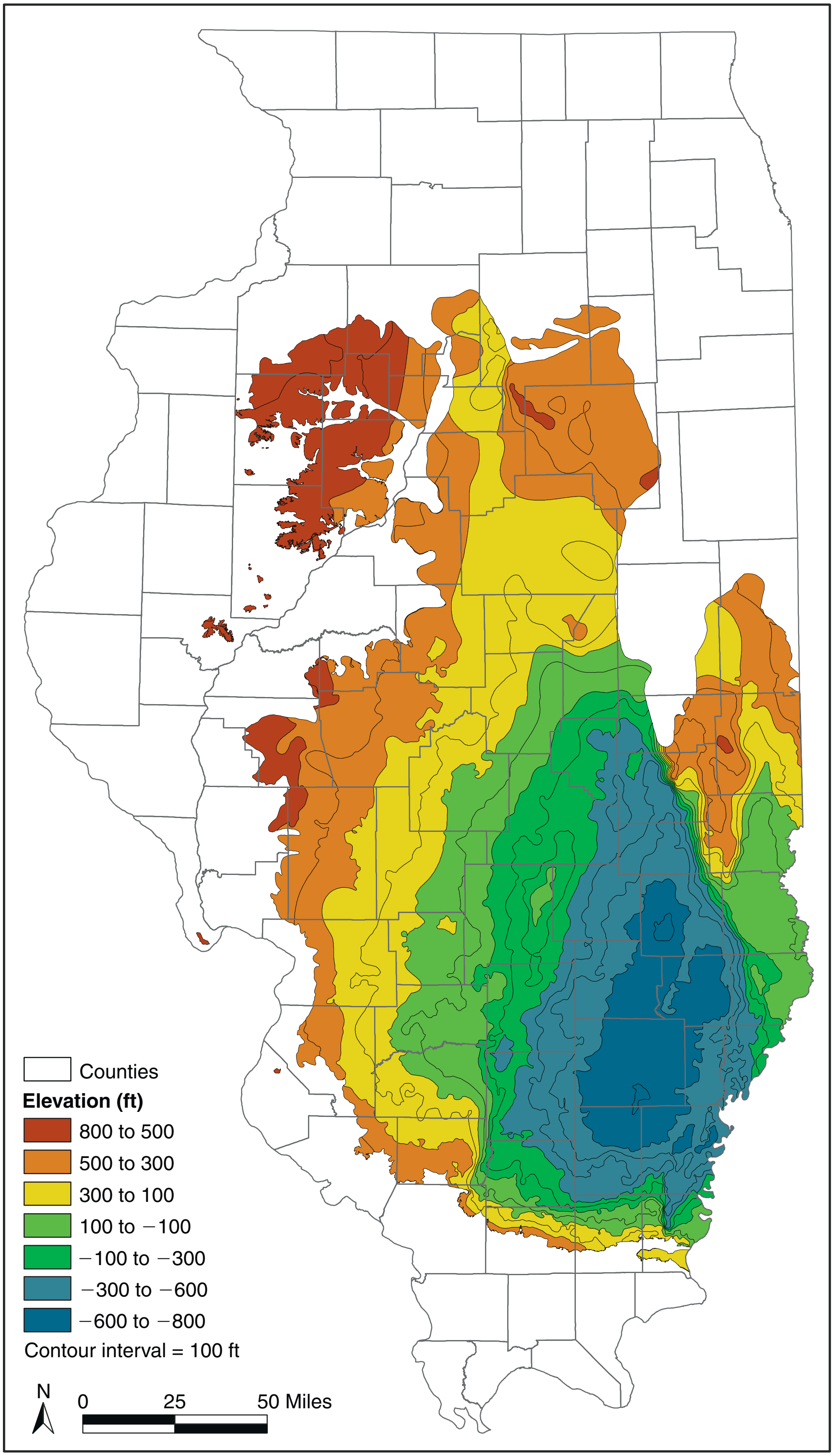


Figure 45 Springfield (No. 5) Coal elevation with respect to mean sea level.

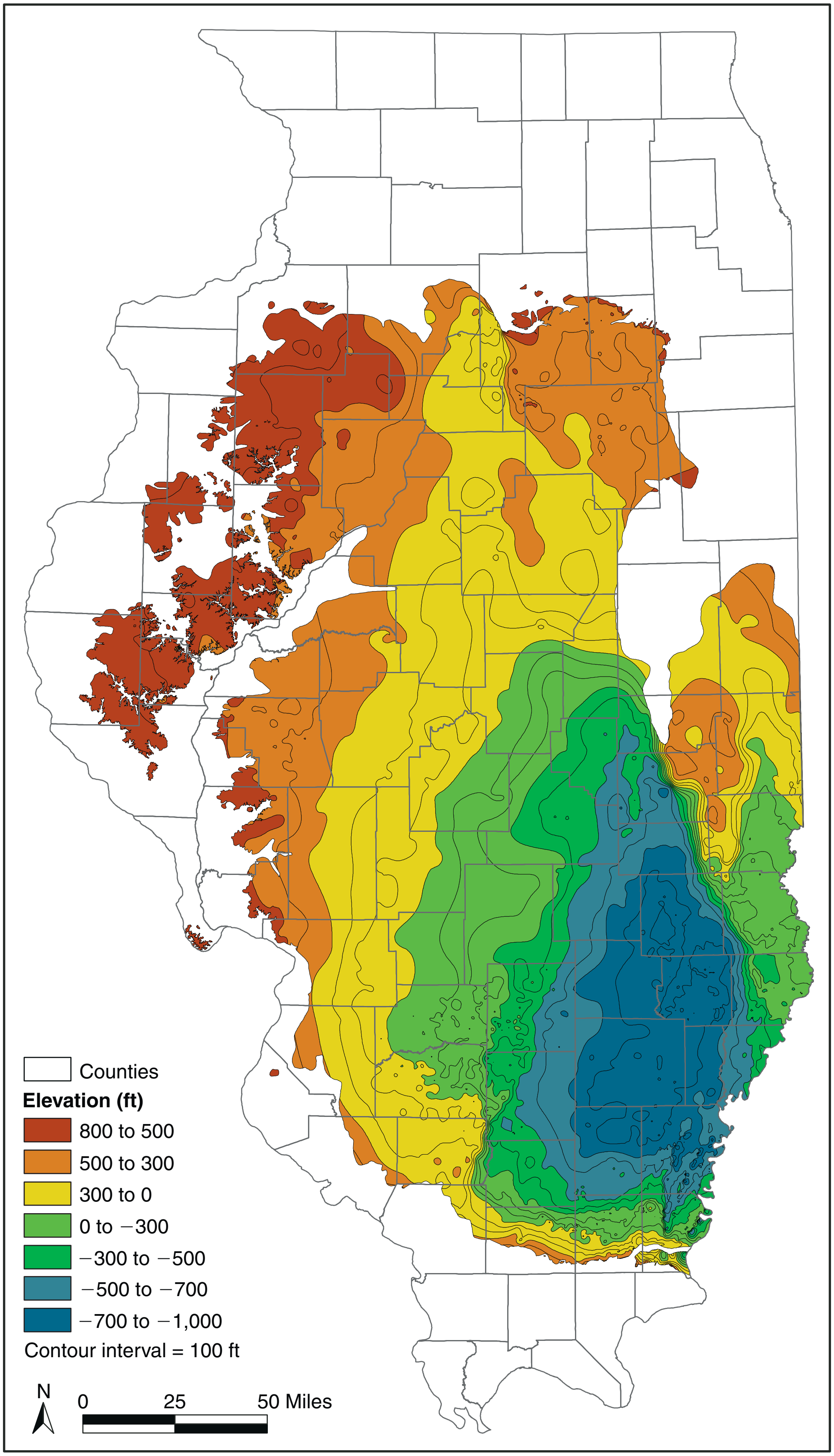


Figure 46 Colchester (No. 2) Coal elevation with respect to mean sea level.

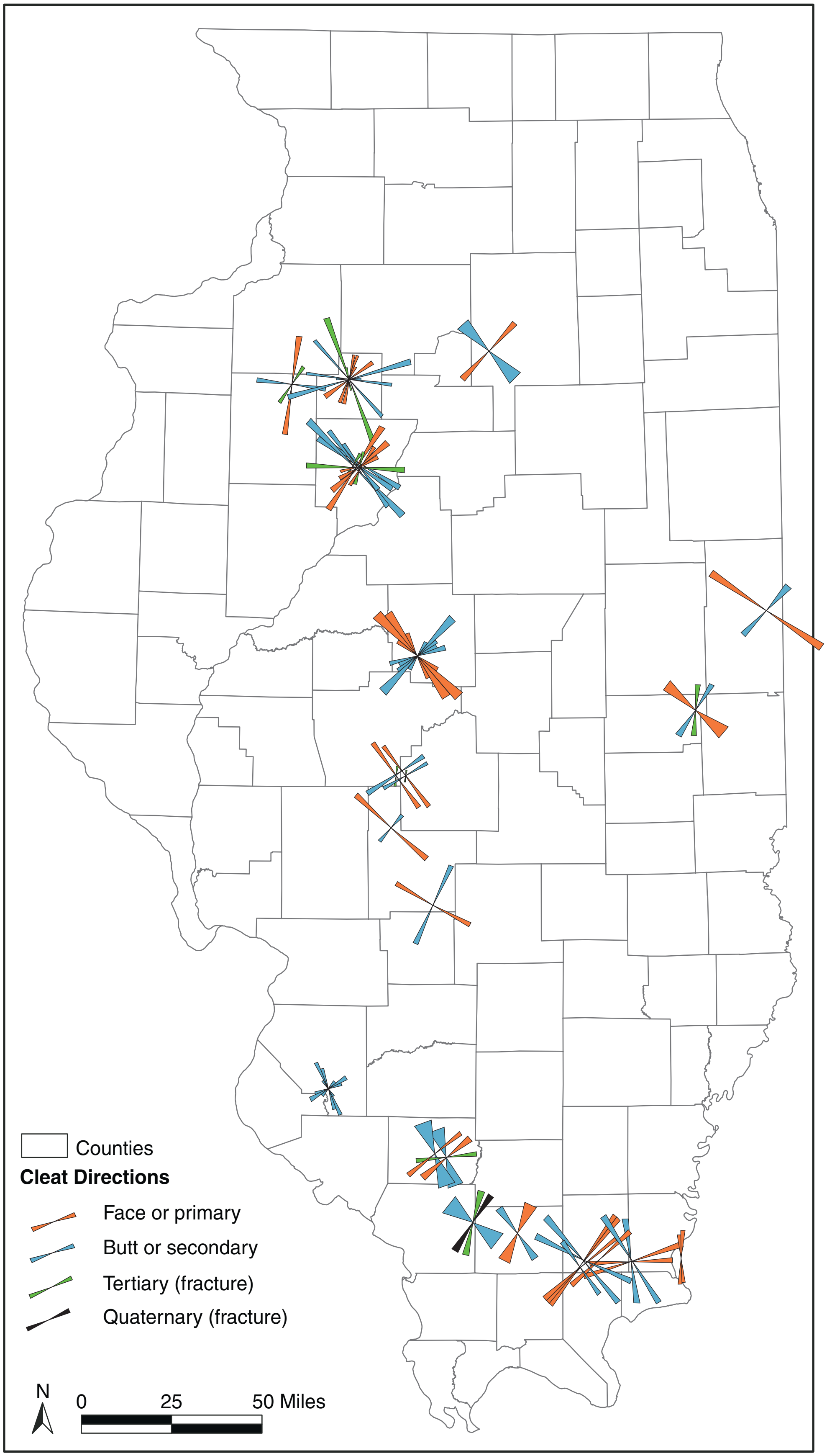


Figure 47 Cleat orientation in the Herrin (No. 6) Coal.

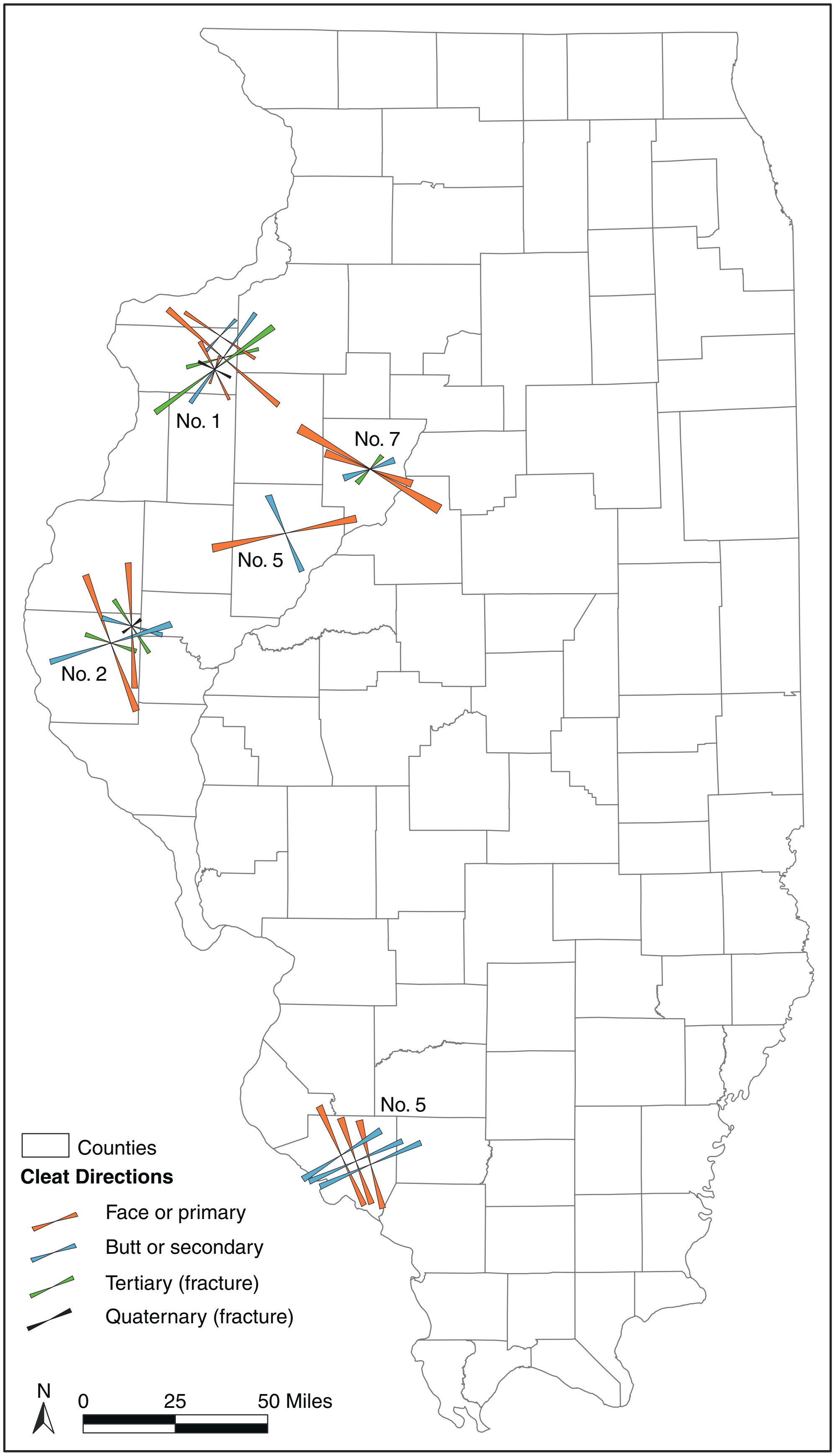


Figure 48 Cleat orientation in Rock Island (No. 1), Colchester (No. 2), Springfield (No. 5), and Danville (No. 7) Coals.

Coal Water Chemistry

Production of CBM involves pumping out the formation water to reduce pressure and desorb the coal gas. Knowing the water chemistry is important not only for determining the hydrodynamics of the area but also for planning the disposal of the produced water while meeting environmental requirements. Gluskoter (1965) reported 994 ppm to 48,306 ppm TDS contents for groundwaters associated with Illinois coals (table 11). Generally the TDS content increases as coal depth increases. Water produced from a CBM production test well near our stratigraphic test hole in Franklin County has over 44,000 mg/L of TDS (table 11), which indicates that the produced water from future deep CBM production wells would require subsurface disposal. Water from shallow coals such as those in Christian, Douglas, and Williamson Counties may be sufficiently fresh for surface disposal. Waters from CBM operations in the shallow coals in Sullivan County, Indiana, are reported to meet surface disposal requirements (Tom Hite, personal communication).

Conclusions and Recommendations

Coalbed methane is likely to play a large role in meeting the increasing natural gas demand in the United States over the next few decades. Illinois has been overlooked in the past, but has the potential to contribute to meeting this demand; the state presently is producing only small amounts of CMM and no CBM.

This ISGS project was conducted to generate additional and improved coal and coal gas data to assist operators considering CBM play development in Illinois. Five wells were drilled and continuously cored, which enabled the collection of 59 coal and 5 shale samples for gas and other analyses. The wells were drilled in Richland, Franklin, Clark, Macoupin, and Bureau Counties. The conclusions derived from the project results are as follows:

- Illinois coals may contain 25 to 100% more CBM than previously thought. Many coals in Clark and Franklin Counties have gas contents of 100 to 173 cu ft/ton on a dmmf basis. These gas values from the desorption tests should be considered minimum values due to the possibility of some gas loss from the coal cores during drilling. Anomalously low gas contents (5 to 6 scf/t) in the Bureau County well are likely the result of gas loss to nearby old mines abandoned about 80 years ago or to a nearby outcrop. Therefore, the conclusions here are exclusive of the Bureau County data. Conservatively estimated CBM resources of the Illinois Basin are 21 to 25 Tcf; at least 14 Tcf of these resources are likely to be in the Illinois portion of the basin.
- Several black shales occurring stratigraphically in close proximity to coals can potentially produce gas along with the coals. Shale gas contents ranged from 52 to 145 scf/t on a dmmf basis, which is equivalent to 10 to 41 scf/t on an as-received, whole rock basis.
- Coal and shale gas samples comprise mostly methane along with

Table 11 Analyses of groundwater samples associated with Herrin Coal in Illinois.

				Concentration in water samples from underground mines (ppm)[1]										
County	Laboratory no.	Depth (ft)	pH	TDS	Cl	SO_4	Na and K (as Na)	Fe	Mn	Ca	Mg	SiO_2	Alkalinity (as $CaCO_3$)	Hardness (as $CaCO_3$)
Christian	160139	355	7.6	25,038	14,875	9.1	9,140	1.9	0.4	300	170	8.6	336	1,450
	160140	355	7.5	24,978	14,875	7.4	9,142	2.9	0.5	300	168	8.6	332	1,440
	160141	386	7.5	24,436	14,625	4.1	9,055	1.3	0.3	264	153	8.1	348	1,290
Douglas	161094	205	8.0	2,856	1,240	6.6	1,076	2.7	trace	22	11	8.2	684	100
	161095	205	8.0	2,886	1,250	10.7	1,092	2.2	0.1	22	10	8.0	696	96
Franklin	160019	653	7.5	38,236	22,800	0.0	13,500	0.0	0.4	672	316	6.9	160	2,980
	160020	653	8.1	37,936	22,800	0.0	13,504	0.0	0.5	664	316	8.5	168	2,960
	160035	450	7.6	30,214	18,000	18.9	10,771	0.1	0.3	436	275	7.1	236	2,220
	160036	450	7.6	30,376	18,200	34.6	10,905	0.1	0.3	436	275	7.1	228	2,220
Jefferson	160148	795	7.4	42,466	25,750	9.9	15,135	3.3	0.8	824	360	7.4	168	3,540
	160149	765	7.4	42,788	26,000	4.9	15,292	2.2	1.0	840	367	7.7	188	3,610
	160150	769	7.0	48,306	29,250	20.6	17,059	8.7	0.9	1,008	452	6.8	200	4,380
Montgomery	161577	380	8.0	12,726	730	28.8	4,822	9.6	1.0	107	52	7.1	644	484
Randolph	160802	150	8.0	5,094	2,400	1.6	1,967	trace	0.1	18	17	8.6	1,004	114
	161138	120	7.9	3,492	1,510	0.0	1,365	0.4	0.1	10	9	8.3	900	62
Williamson	159840	185	8.3	3,942	1,480	622.0	1,477	0.0		17.6	7.8	10.0	552	76
	160419	161	7.7	2,320	1,030	6.6	859	0.1	0.1	36	17	13.8	568	160
	160420	143	7.6	2,984	1,583	2.5	943	0.7	0.1	131	56	13.9	376	560
	160421	143	7.6	1,534	595	21.4	518	0.1	0.1	44	21	22.1	460	196
	160417	440	8.6	994	162	6.6	408	0.6	0.0	2	1	9.8	660	8
	160418	440	8.6	1,002	150	3.3	406	0.5	0.0	2	1	9.8	676	8

		Concentration in water samples collected from a CBM production test well (mg/L)														
		pH	TDS	Cl	SO_4	Na	K	Fe	Mn	Ca	Mg	Si	Al	Ba	Sr	Br
Franklin	B05674	ND	44,590	23,420	<2	14,700	<10	7.9	1.03	702	329	2.4	<0.1	17.8	30.3	58
	B05675	ND	44,480	23,470	<2	14,800	<10	8.1	1.06	709	334	2.7	<0.1	17.9	30.2	56

[1]From Gluskoter (1965).

- minor amounts of other combustible gases; gas purity is higher for deeper coals. Although the measured combustible gas contents are ~56 to 96%, the actual gas purity may be greater because of the possibility of air contamination and the resulting reduction in combustible gas contents.

- Coal gases are mostly biogenic gases with small amounts of thermogenic gas contribution.

- Gas contents generally, but not always, increase with depth and coal rank, suggesting that deeper and higher rank coals in the state are better targets for CBM exploration, although exploration for shallower but high permeability coals should not be ruled out.

- Coal gas saturations range from 34 to 70%; in situ saturations are most likely somewhat higher because of undetermined gas losses during drilling.

- Digital maps produced to delineate various coal resource parameters and geological structures that are relevant to CBM will greatly aid in determining which areas have high CBM development potential in Illinois. Large areas with multi-seam total thicknesses greater than 20 ft and reasonable gas contents exist in eastern, southeastern, and southern Illinois.

Future Studies

Future studies should involve mapping of hydrogeological parameters and developing the most effective CBM well completion and stimulation techniques for Illinois Basin coals in order to evaluate the potential for commercial CBM production in the basin. Little or no work has been done in Illinois to evaluate various CBM well stimulation and recovery techniques such as advanced hydraulic fracturing, horizontal drilling, open hole cavitation, and recovery through CO_2 injection.

A multi-year pilot program should be implemented in an area with high CBM potential to evaluate coal permeability, well stimulation, and gas production. The pilot project can be initiated by industry or by an industry-government partnership, and the data should be freely available to the public. An example of such a project might involve drilling and casing four wells at the perimeter and a fifth well at the center on 10- or 20-acre spacing. The center well would first be cored to the base of the deepest prominent coal to measure gas content and gas composition of significant coals in the stratigraphic section. Then, this well would be enlarged to $7^5/_8$-inch diameter, cased with 5-inch pipe, cemented, and perforated in the coals with the highest potential.

Pressure transient tests would be made in each of the selected coal seams to determine their permeabilities. With the permeability, well spacing, and gas content information, proper hydraulic fracturing parameters would be designed to complete the wells for a pilot project of commercial CBM production. All five wells would be hydrofractured in the coals of the highest potential and put on pump to draw down the water pressure. The center well would become the main gas producer while the outer wells would prevent water influx and possibly produce lesser amounts of gas. Gas and water quantities would be recorded, and peak production of gas would be expected within 1 year.

If the project proved to be commercially feasible, the operator could readily add adjacent wells that would dewater larger areas and expand the production. Another potential pilot program would involve the application of advanced horizontal drilling and stimulation technologies that might be suitable for the relatively thin but laterally extensive Illinois coals. The pilot production programs would demonstrate the gas volumes that a well-designed drilling and completion program would produce in a setting favorable to CBM production in the Illinois Basin.

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Appendices

Appendix 1: Illinois coal mine disasters

Table A1 Illinois coal mine disasters (incidents with five or more fatalities).[1]

Date	Mine name	Location	Fatalities (no.)	Type
01/09/1883	Coulterville	Coulterville	10	Explosion
02/16/1883	Diamond	Braidwood	69	Inrush of water
03/15/1903	Cardiff	Cardiff	5	Explosion
03/23/1903	Athens, No. 2	Athens	6	Explosion
03/31/1903	Sandoval	Sandoval	8	Explosion
05/11/1904	Big Muddy	Herrin	10	Explosion
01/16/1905	No. 1	Decatur	6	Fire
04/03/1905	Zeigler	Zeigler	49	Explosion
12/22/1906	Breese-Trenton	Breese	6	Haulage
01/10/1909	Zeigler	Zeigler	26	Explosion
11/13/1909	Cherry	Cherry	259	Fire
12/23/1909	Mine A	Herrin	8	Explosion
11/11/1910	Shoal Creek No. 1	Panama	6	Explosion
10/23/1911	O'Gara No. 9	Harrisburg	8	Explosion
02/19/1913	Seagraves	Eldorado	5	Explosion
10/27/1914	North or No. 1	Royalton	52	Explosion
04/05/1915	Shoal Creek	Panama	11	Explosion
07/27/1915	United Coal No. 1	Christopher	9	Explosion
06/02/1917	Rend No. 2	Herrin	9	Explosion
09/17/1917	Orient	Orient	5	Haulage
11/29/1917	Old Ben No. 11	Christopher	18	Explosion
09/28/1918	North	Royalton	21	Explosion
02/23/1921	Kathleen	Dowell	7	Fire
08/31/1921	Harco	Harrisburg	12	Explosion
09/29/1922	Lake Creek	Johnston City	5	Explosion
01/25/1924	McClintock	Johnston City	33	Explosion
03/30/1927	Saline No. 2	Ledford	8	Explosion
12/20/1927	Franco No. 1	Johnston City	7	Explosion
01/09/1928	No. 18	West Frankfort	21	Explosion
01/29/1926	New Orient No. 2	West Frankfort	5	Explosion
12/01/1929	Old Ben No. 8	West Frankfort	7	Explosion
12/24/1932	Moweaqua	Moweaqua	54	Explosion
08/01/1936	Kathleen	Dowell	9	Fire
12/28/1941	No. 47	Harco	8	Explosion
03/25/1947	No. 5	Centralia	111	Explosion
07/24/1947	Old Ben No. 8	West Frankfort	27	Explosion
12/21/1951	Orient No. 2	West Frankfort	119	Explosion
01/10/1962	Blue Blaze No. 2	Herrin	11	Explosion
Total fatalities			1,050	

[1]From National Institute for Occupational Safety and Health (2002).

Appendix 2: Summary sheets of sample information and gas content measurements for all coal and shale samples from the five ISGS test wells