Resource Assessment & Production Testing for Coal Bed Methane in the Illinois Basin
Final Report
Reporting Period Start Date – 10/01/03
Reporting Period End Date – 11/30/05

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Issuing Date – November, 2005

Award Number - DE-FC26-03NT41876

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ABSTRACT

In order to assess the economic coal bed methane potential of the Illinois Basin, the geological surveys of Illinois, Indiana and Kentucky performed a geological assessment of their respective parts of the Illinois Basin. A considerable effort went into generating cumulative coal thickness and bed structure maps to identify target areas for exploratory drilling. Following this, the first project well was drilled in White County, Illinois in October 2003. Eight additional wells were subsequently drilled in Indiana (3) and Kentucky (5) during 2004 and 2005. In addition, a five spot pilot completion program was started with three wells being completed. Gas contents were found to be variable, but generally higher than indicated by historical data. Gas contents of more than 300 scf / ton were recovered from one of the bore holes in Kentucky. Collectively, our findings indicate that the Illinois Basin represents a potentially large source of economic coal bed methane. Additional exploration will be required to refine gas contents and the economics of potential production.

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EXECUTIVE SUMMARY

The Illinois Basin has over 325 billion tons of remaining coal resources that is estimated to contain 11 trillion cubic feet (Tcf), or more, of coalbed methane (CBM). To date, very limited amounts of this CBM have been produced, mainly because historical data have indicated low, uneconomic, gas contents. However, more recently acquired data indicate that gas contents in certain areas within the basin may be much higher than previously considered. Coal production within the basin continues to decline, mainly because of the high sulfur contents of most of the economic coal beds. CBM may be an effective way to use this vast energy resource to help meet the increasing demand for natural gas. Development of this resource would also contribute to the energy security of the nation, as a whole, and be a source of hydrogen for emerging fuel cell technology. This report summarizes project activities for the first twelve months. It should be noted that all analytical data have not been accumulated. Several samples are still in the process of being desorbed, and much analytical data is still pending.

Initially, the state geological surveys of Illinois, Indiana and Kentucky completed their geologic assessments of their respective parts of the Illinois Basin. Maps of cumulative coal thickness and coal structure maps were generated to target areas for drilling. The first well in Illinois was drilled in White County, Illinois in October 2003. Subsequent drilling of eight additional boreholes in Indiana and Kentucky occurred during 2004-2005. Collectively, data from the drilling program indicates that coal in the stratigraphic target interval, which includes the Danville to Davis coals, approaches a cumulative thickness of nearly 25 ft, with individual bed thicknesses ranging from 1.0 to just under 6.0 ft. Gas contents of collected coal and organic-rich shale samples are highly variable, from less than 50 scf/ton to more than 300 scf/ton. Overall, gas contents were found to be higher than previously considered. One caveat is that for many samples, much of the desorbed gas is only liberated after crushing the sample to measure residual gas content. Residual gas is largely, if not entirely, unrecoverable and probably is indicative of low permeability.

Gas analyses indicate a high concentration of methane, with lesser amounts of higher hydrocarbon (C_2 – C_4) and other gases (e.g., carbon dioxide and nitrogen). Gas isotope data indicates that much of the gas in less deeply buried samples (<500 ft of cover) is mainly biogenic in origin, whereas gas from more deeply buried samples (>1000 ft of cover) is dominantly thermogenic in origin. This is an important finding as it indicates that relatively shallow coal may still contain economic methane of samples is much higher, ranging from 521 to 788 scf/ton. Additional analyses on these samples are currently underway.

INTRODUCTION

The Illinois Basin has over 325 billion tons of remaining coal resources that is estimated to contain 11 trillion cubic feet (Tcf), or more, of coal bed methane (CBM). To date, very limited amounts of CBM have been produced, mainly because historical data have indicated low, uneconomic, gas contents. However, data from this study indicate that gas contents in certain areas within the basin are much higher than previously thought. As coal production within the basin continues to decline, mainly because of the high sulfur contents of most of the coals, production of CBM may be an effective way to use this vast, but progressively idled, energy resource in an environmentally sound manner.

The goal of this project was to obtain fundamental CBM content, permeability, and well completion data for Illinois Basin coals from a selected set of core holes. Nine (9) exploration cores were drilled in the basin to depths up to 2,000 feet. The well sites will be selected on detailed geological analysis to determine the best possible areas for economic CBM. Project results will hopefully encourage and support industry as they attempt to develop this important energy resource.

EXPERIMENTAL

Coal samples collected from the drilling program were degassed in standard CBM desorption canisters for a period of 2 to 6 months, depending on the rate of gas release. After complete desorption, the coal samples were crushed in an air-tight ball mill, or in a large capacity hammer mill, to obtain residual gas measurements. Residual gas measurements were recorded for an additional 2 to 6 weeks. Following the measurement of residual gas the crushed coal was further analyzed for a variety of parameters including:

1) proximate analysis (moisture, volatile matter, fixed carbon and ash yield)
2) total sulfur content
3) calorific value
4) petrography (maceral analysis and vitrinite reflectance)
5) methane adsorption capacity (isotherm analysis)

Both in-house and private laboratories are used to perform these analyses.

RESULTS AND DISCUSSION BY STATE

Illinois

The first well in the Illinois area of the Illinois Basin coalbed methane project, the Jim Cantrell, Hon #9, was drilled in White County, Illinois in October 2003. The well was drilled in the New Harmony Oil Field in an area of low local structural relief (see figure 1). This well will become the center well for our production pilot and will provide core data for the area. A mile or two east and west of this well lie normal faults of the Wabash Valley Fault system that trend northeast-southwest. The Hon #9 was cored in the major coal intervals from the Danville to the Davis Coals and provided a broad spectrum of samples for further analyses. The well was subsequently reamed to 7 7/8" and cased with 5 1/4" pipe. Sixteen coal samples and three black shale samples were taken from these cores for canister desorption tests, including desorbed gas volume, gas chemical and isotope composition, coal proximate, calorific and sulfur contents, and adsorption isotherm analyses. Results are tabulated below.

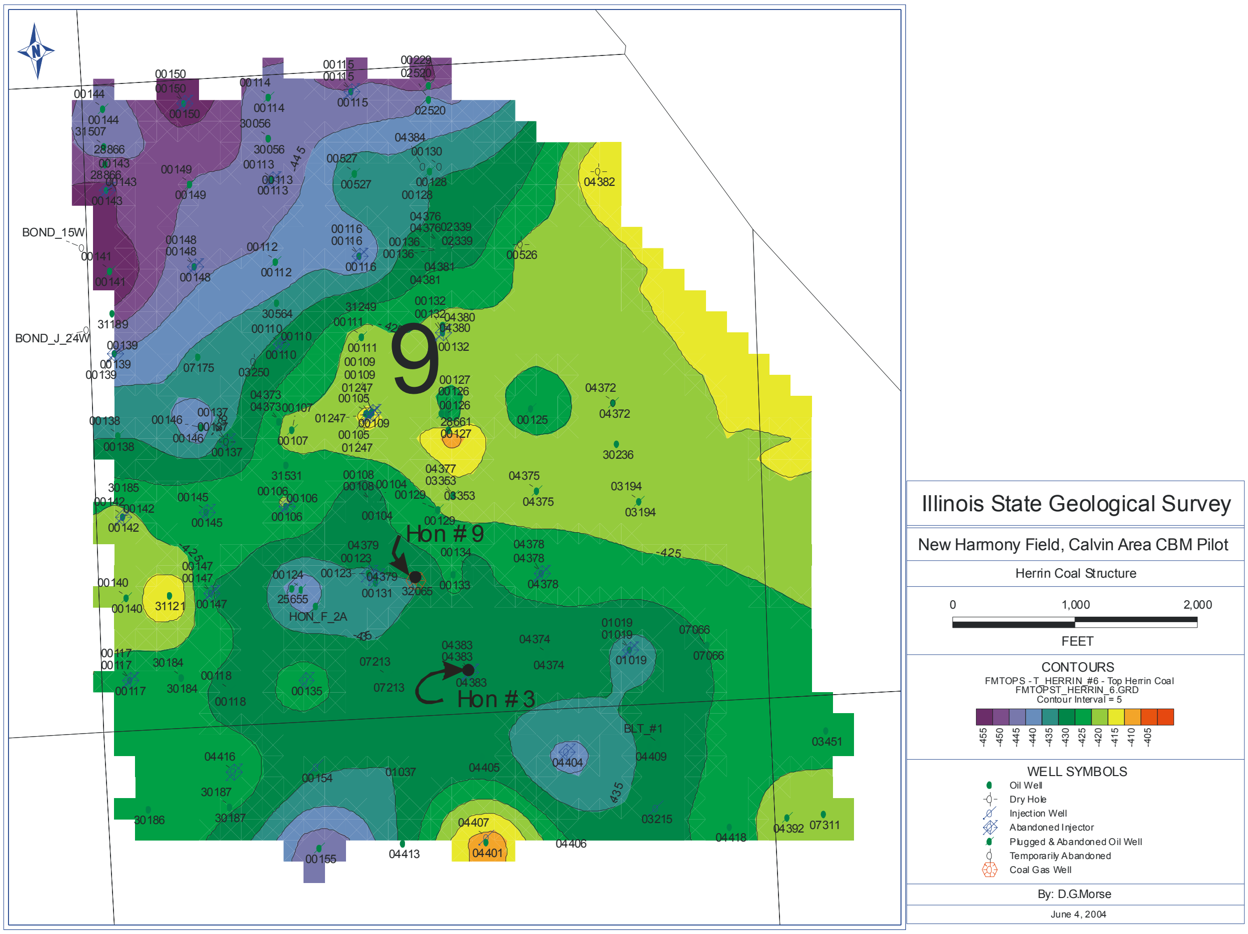

Figure 1. Herrin Structure Map in Pilot area, Sec. 9, T4S, R14W, White County, Illinois

One of the potential dewatering wells in the White County pilot was completed in November, 2003, the #3 Hon. This well is a recompleted old well that formerly produced from a deep Mississippian pay. It had been plugged. Royal Drilling re-entered the old borehole, removed the surface plug and washed down the old hole. Although casing was in the hole, it was not cemented across the coals. The old casing was cut off below the coals of interest and new casing was placed in the hole and cemented, thus providing good hole integrity though the coal zones. Correlations to the #9 Hon, which lies about 700 feet to the north-northwest, are shown in figure 2 using the old SP-Resistivity log available from the #3 Hon and the GR-Den log from the #9 Hon.

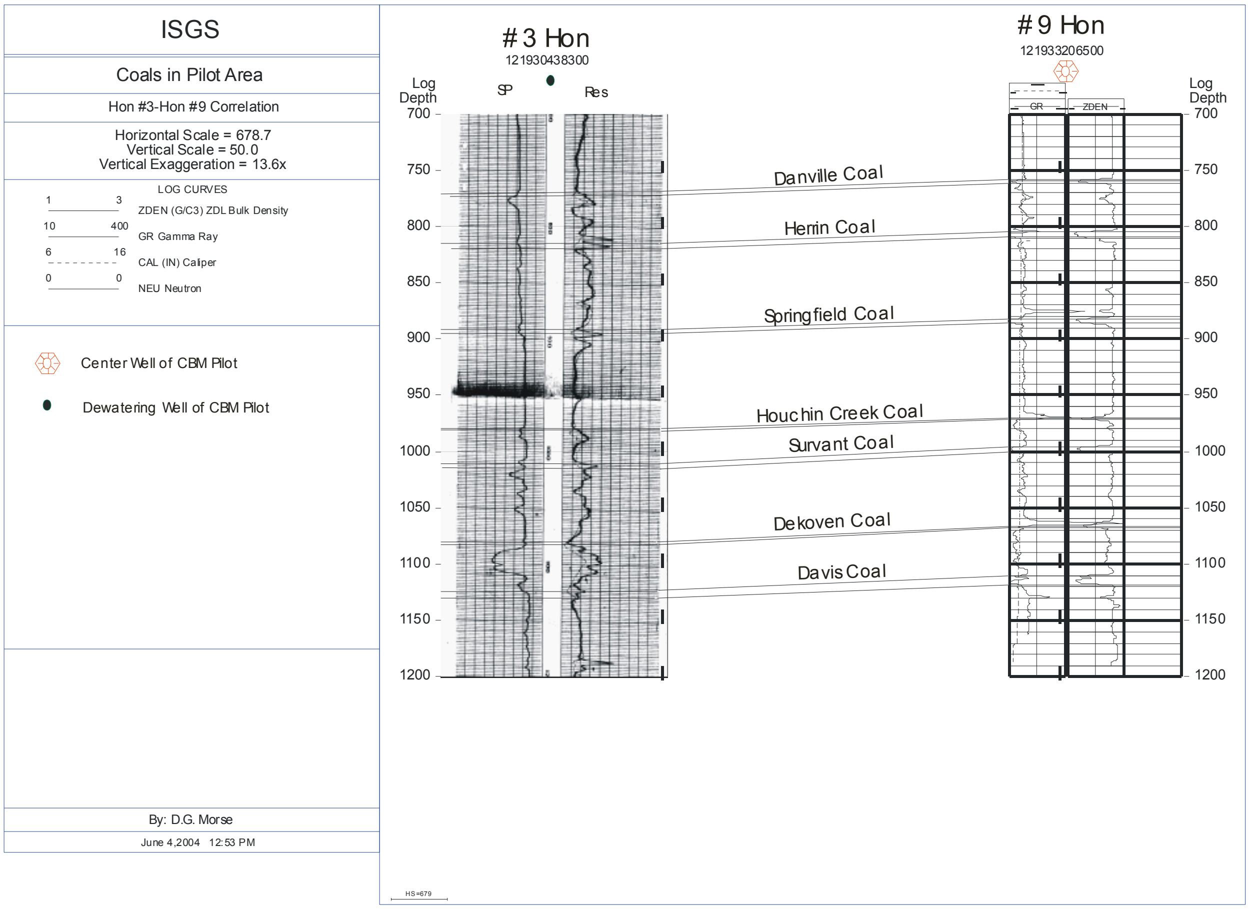

Figure 2. Cross-section from the #3 Hon to the #9 Hon wells in the White County Pilot Project.

Depths and thicknesses for the major coals in the pilot area at #9 Hon are shown in Table 1. These are derived from the GR-Density log in the #9 Hon and are compared to the actual cored coal thickness. The total coal drilled in the pilot area is about 24 feet. The thin Houchin Creek (#4) coal will not be a part of the pilot because it closely overlies a porous, water-bearing sandstone that we are unlikely to dewater successfully.

Table 1. Coal Tops from James Cantrell #9 Hon well log and actual coal core thicknesses

Coal	Top (ft)	Base (ft)	Thickness (ft)	Core coal thickness (ft)
Danville	758.0	762.0	4.0	3.6
Herrin #6	806.0	810.0	4.0	5.0
Springfield #5	882.0	886.0	4.0	4.0
Houchin Creek #4	971.0	972.0	1.0	1.5

Survant #3	996.0	1000.0	4.0	4.1
Colchester #2	1066.0	1068.0	2.0	1.6
Davis- upper split	1110.0	1111.5	1.5	1.4
Davis- middle split	1114.0			2.1
Davis- lower split		1118.0	4.0	1.2
Total			25.5	24.5

Note: Between upper and middle split in Davis coal is 1' 3" of carbonaceous shale and siltstone
Between Middle and lower split in Davis coal is 4" of carbonaceous shale with some pyrite partings.

Proximate, heating value, and sulfur analyses were run on all the samples as these values are needed for the gas content calculations. The results are summarized below in Table 2.

Table 2. As-Received Proximate/Btu/S Analyses

Royal Drilling#9 Hon Well

Sample No.	Depth (ft)	Moisture (wt %)	Ash (wt %)	Volatile Matter (wt %)	Fixed Carbon (wt %)	Heating Value (Btu/lb)	Sulfur (wt %)	Coal Rank
D1-Danville Coal	756.2	7.31	10.27	35.48	46.94	11815	4.63	hvBb
D2-Danville Coal	759.7	6.95	24.32	31.16	37.57	9647	2.81	hvBb
D3- Herrin Coal	803.5	7.10	14.34	34.25	44.30	11068	5.07	hvBb
D4-Herrin Coal	805.0	8.66	6.56	34.38	50.40	12221	2.24	hvBb
D5- Herrin Coal	807.0	7.76	10.97	33.91	47.36	11592	2.84	hvBb
E1-Turner Mine Shale	874.0	2.25	66.47	19.79	11.49	4302	2.40	-
E2- Springfield Coal	880.8	6.06	10.58	35.28	48.08	12080	2.83	hvBb
E3-Springfield Coal	882.7	6.65	7.43	37.24	48.68	12384	2.18	hvBb
E4- Springfield Coal	883.7	6.72	10.57	34.75	47.96	12017	1.54	hvBb
E5- Excello Shale	967.4	2.70	71.93	15.20	10.17	3360	2.86	-
C2- Houchin Creek Coal	968.7	4.91	9.57	40.02	45.50	12087	6.46	hvBb
C3- Survant Coal	993.9	5.67	9.17	37.88	47.28	12050	5.28	hvBb
C4- Survant Coal	994.7	5.35	9.54	38.70	46.41	12477	3.91	hvAb
C5- Survant Coal	996.4	5.22	9.18	38.64	46.96	12544	2.48	hvBb
A1- Mecca Quarry Shale	1058.0	3.48	81.50	13.81	1.21	1137	4.67	-
A3- Dekoven Coal	1062.5	4.51	25.24	33.91	36.34	10187	2.85	hvAb
A4-Davis Coal	1107.5	4.47	17.34	35.42	42.77	10977	11.43	hvBb
A5-Davis Coal	1111.3	5.05	10.09	39.40	45.46	12277	4.86	hvBb
B1- Davis Coal	1113.7	4.73	11.45	37.58	46.24	11877	6.88	hvBb

Gas content values were determined for the 16 coal and 3 shale samples after four months of canister desorption. They are reported below in Table 3 on a dry, mineral-matter-free basis. The values are typical of samples we analyzed in our previous drilling program. The best coal was the Davis Coal. This is equivalent to the Seeleyville Coal that is the reservoir of a coalbed methane operation in Sullivan County, Indiana. Lost gas values are typically very low, reflecting the slow desorption rate of the coals and short lost gas times. Residual gas values were determined by an outside contractor and entered in the total gas computation. Three black shale samples were also analyzed as they will likely contribute to the gas resource. Because of their inherent high mineral matter content, their gas contents appear to be overly high. The as-received basis values shown at the base of the table put their contents into perspective. A ton of coal in the ground may have 3 to 5 times more gas than a ton of shale. Volumetrically, however, for a 2.00 g/cc carbonaceous shale there are 2715 tons per acre-ft compared to 1800 tons per acre-ft for a 1.324 g/cc coal; even more gas if the shale has some pyrite and is heavy.

Table 3. Gas contents of coal and shale samples from #9 Hon well

		Gas content (scf/t, dmmf basis)			
Canister	Sample	Lost	Desorbed	Residual	Total
D1	Danville 1	2.3	73.2	17.9	**93.4**
D2	Danville 2	2.5	87.3	5.5	**95.3**
D3	Herrin 1	2.0	70.5	13.8	**86.3**
D4	Herrin 2	3.2	74.3	13.7	**91.2**
D5	Herrin 3	2.0	67.9	14.3	**84.2**
E2	Springfield 1	1.0	54.8	20.2	**76.0**
E3	Springfield 2	1.9	66.7	14.7	**83.3**
E4	Springfield 3	2.5	64.3	14.8	**81.6**
C2	Houchin Creek	0.6	53.5	27.4	**81.5**
C3	Survant 1	1.4	71.6	19.4	**92.4**
C4	Survant 2	1.0	72.2	15.1	**88.3**
C5	Survant 3	1.1	72.4	11.5	**85.0**
A3	Dekoven	1.0	71.0	21.3	**93.3**
A4	Davis 1	3.3	94.0	21.4	**118.7**
A5	Davis 2	3.7	87.7	18.6	**110.0**
B1	Davis 3	1.8	68.1	16.5	**86.4***
E1	Turner Mine Sh.**	0.3	72.9	14.7	**87.9**
E5	Excello Sh.**	2.4	112.2	6.3	**120.9**
A1	Mecca Quary Sh.**	0.0	65.7	78.7	**144.4**

* Suspected slight gas leak from the canister during desorption tests
** As-received total gas contents of Turner Mine, Excello, and Mecca Quarry shales are 21.7, 21.8, and 8.6 scf/t, respectively.

Gases desorbed from the coal and shale samples were analyzed for their chemical and isotope (hydrogen and carbon) compositions. Successive gas samples were taken from each canister for chemical and isotope composition analyses. The results are shown in Table 4 and the plots below. Methane quantities increase with successive samples, largely reflecting the dilution of headspace gas with coal gas over time. True formation methane gas is likely to be richer in methane than shown here.

The nitrogen values have been corrected to compensate for atmospheric nitrogen in the canister headspace and lines. The entire O2 and the portion of N2 that balances O2 in atmospheric air were subtracted from the canister gas sample values. However, the nitrogen value may not be fully corrected because an unknown quantity of contaminant O2 from the air may have been consumed by oxidation of the coal. Its companion atmospheric nitrogen would remain unaccounted for and not be subtracted from the total N2 content. Thus, N2 originally adsorbed on the coal in the subsurface is probably less than the value reported here due to undercounting the atmospheric correction.

Hydrogen (deuterium) and Carbon 13 stable isotope compositions are very uniform and are consistent with a microbial to early transitional thermal origin of the methane (figure 3). In the shallower coals, such as the Danville and Herrin, coal methane isotopes clearly indicate a microbial origin, whereas the deeper coal gases show a slightly more thermogenic origin. This is evident in the C13 isotope vs depth plot shown in figure 4. The quantity of C2+ gases, another thermogenic indicator, also increases with depth.

Table 4. Desorbed Gas Chemical and Isotope Composition, #9 Hon

	Coal	Gas composition, %					CH_4 isotope values	
Gas sample	**Depth (ft)**	**N_2**	**CO_2**	**CH_4**	**C_{2+}**	**$CH_4 + C_{2+}$**	**$d^{13}C$**	**d D**
HON-D1-A DANVILLE 1(dup. isotopes)	756.2	31.27	1.23	67.50	0.00	67.5	-69.9	-214.1
HON-D1-B DANVILLE 1	756.2	33.20	1.18	65.63	0.00	65.6	-69.2	-214.5
HON-D1-C DANVILLE 1	756.2	21.97	1.33	76.67	0.03	76.7		
HON-D2-A DANVILLE 2	759.7	24.09	1.20	74.71	0.00	74.7	-70.4	-212.1
HON-D2-B DANVILLE 2	759.7	21.84	1.30	76.86	0.00	76.9	-70.2	-215.0
HON-D2-C DANVILLE 2	759.7	13.76	1.23	85.01	0.00	85.0	-69.9	-214.7
HON-D3-A HERRIN 1	803.5	31.96	2.21	65.16	0.67	65.8	-70.8	-215.9
HON-D3-B HERRIN 1	803.5	31.85	2.12	65.29	0.74	66.0	-70.4	-217.2
HON-D3-C HERRIN 1	803.5	23.47	2.11	73.54	0.89	74.4		
HON-D4-A HERRIN 2	805	34.70	1.90	62.64	0.76	63.4	-69.9	-216.4
HON-D4-B HERRIN 2	805	34.30	1.86	62.98	0.86	63.8	-69.8	-218.6
HON-D4-C HERRIN 2	805	22.10	1.93	74.79	1.17	76.0		
HON-D5-A HERRIN 3	807	31.85	1.74	65.61	0.80	66.4	-69.7	-214.7
HON-D5-B HERRIN 3	807	28.86	1.77	68.44	0.92	69.4	-69.9	-217.5
HON-D5-B HERRIN 3 (2nd run)	807	20.71	1.86	76.26	1.17	77.4	-69.9	-218.6
HON-D5-C HERRIN 3	807	20.71	1.86	76.26	1.17	77.4	-69.7	-217.5
HON-E2-A SPRINGFIELD 1	880.8	24.07	1.62	72.89	1.43	74.3	-66.9	-211.1
HON-E2-B SPRINGFIELD 1	880.8	33.34	1.40	63.94	1.32	65.3	-66.1	-210.0
HON-E2-C SPRINGFIELD 1	880.8	34.12	1.33	63.21	1.33	64.5		
HON-E3-A SPRINGFIELD 2	882.7	27.60	1.28	69.76	1.37	71.1	-66.9	-211.2
HON-E3-B SPRINGFIELD 2	882.7	25.71	1.40	71.29	1.60	72.9	-66.3	-211.2
HON-E3-C SPRINGFIELD 2	882.7	23.12	1.39	73.64	1.84	75.5		
HON-E4-A SPRINGFIELD 3	883.7	37.24	1.42	60.09	1.25	61.3	-67.2	-209.8
HON-E4-B SPRINGFIELD 3	883.7	37.49	1.32	59.86	1.33	61.2	-67.2	-211.3
HON-E4-C SPRINGFIELD 3	883.7	36.58	1.47	60.24	1.70	61.9	-67.1	-211.9
HON-C2-A HOUCHIN	968.7	21.49	1.87	75.29	1.35	76.6	-66.0	-215.0
HON-C2-B HOUCHIN	968.7	33.99	1.56	63.25	1.20	64.4		
HON-C2-C HOUCHIN CREEK	968.7	29.60	1.74	67.28	1.38	68.7	-65.4	-217.0
HON-C3-A SURVANT 1	993.9	28.18	1.71	69.12	1.00	70.1	-66.9	-219.8
HON-C3-B SURVANT 1	993.9	28.03	1.91	68.96	1.10	70.1	-66.8	-220.1

HON-C3-C SURVANT 1	993.9	21.71	1.94	75.01	1.34	76.4		
HON-C4-A SURVANT 2 (dup. isotopes)	994.9	25.57	1.93	71.47	1.03	72.5	-67.0	-218.8
HON-C4-B SURVANT 2	994.9	27.21	2.06	69.64	1.09	70.7	-67.2	-219.1
HON-C4-C SURVANT 2	994.9	24.55	1.91	72.21	1.33	73.5		
HON-C5-A SURVANT 3	996.4	29.92	1.72	67.41	0.95	68.4	-67.0	-220.1
HON-C5-B SURVANT 3	996.4	32.12	1.68	65.17	1.03	66.2	-67.0	-221.3
HON-C5-C SURVANT 3	996.4	21.94	1.75	74.97	1.34	76.3	-66.8	-222.7
HON-A3-A DEKOVEN	1062.5	22.22	1.76	75.81	0.22	76.0	-65.7	-207.6
HON-A3-B DEKOVEN	1062.5	34.55	1.35	63.93	0.17	64.1	-65.0	-207.9
HON-A3-C DEKOVEN	1062.5	34.44	1.30	64.02	0.25	64.3	-64.5	-212.3
HON-A4-A DAVIS 1	1107.5	29.32	1.22	69.11	0.34	69.5	-65.2	-201.8
HON-A4-B DAVIS 1(dup. isotopes)	1107.5	26.21	1.45	72.04	0.30	72.3	-65.2	-205.8
HON-A4-C DAVIS 1	1107.5	16.42	1.55	81.75	0.28	82.0		
HON-A5-A DAVIS 2	1111.3	27.86	1.19	70.64	0.31	70.9	-66.3	-205.2
HON-A5-B DAVIS 2	1111.3	25.75	1.17	72.75	0.33	73.1	-65.2	-206.9
HON-A5-C DAVIS 2	1111.3	16.56	1.40	81.62	0.41	82.0		
HON-B1-A DAVIS 3	1113.7	31.05	1.37	67.26	0.33	67.6	-64.9	-206.2
HON-B1-B DAVIS 3	1113.7	30.13	1.37	68.17	0.33	68.5	-64.6	-204.7
HON-B1-C DAVIS 3	1113.7	21.46	1.61	76.52	0.41	76.9	-64.4	-207.8
HON-E1-A TURNER	874	51.01	0.37	47.58	1.04	48.6	-66.3	-211.1
HON-E1-A TURNER (2nd GC run)	874	51.20	0.00	47.76	1.04	48.8		
HON-E5-B EXCELLO (dup. isotopes)	967.4	56.20	0.28	42.46	1.06	43.5	-66.5	-215.9
HON-A5-A EXCELLO SHALE	967.4	52.89	0.36	45.61	1.14	46.7	-66.9	-215.6

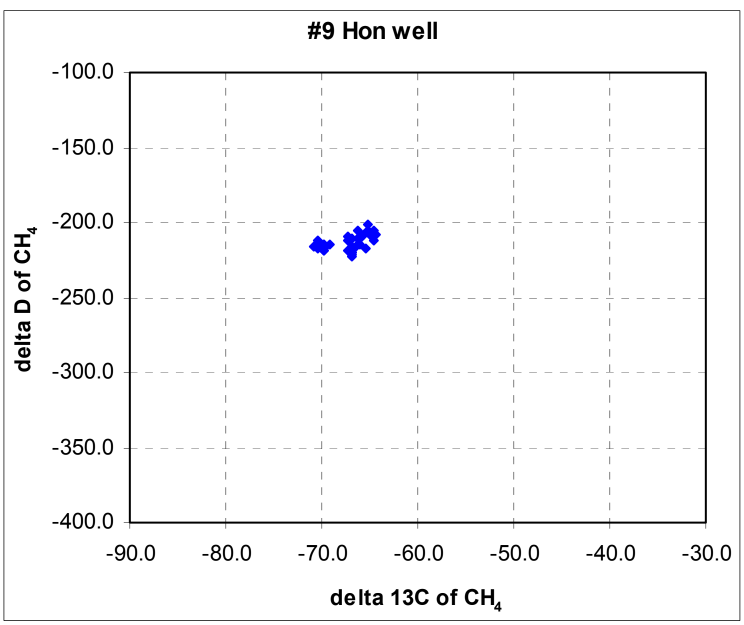

Figure 3. Cross-plot of delta D vs. delta 13C for Hon #9 coal gas methane

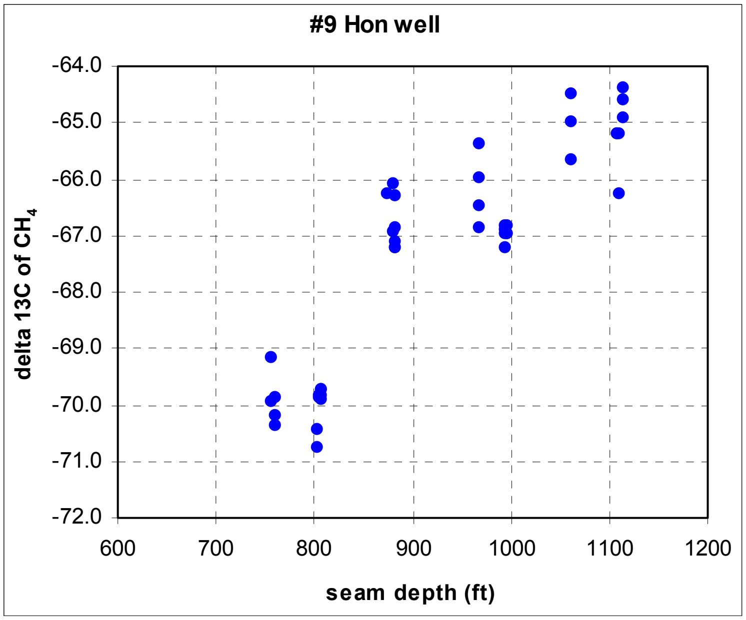

Figure 4. Cross-plot of delta 13C vs. depth for Hon #9 coal gas methane

Isotherm Data- TerraTek completed adsorption isotherm analyses for the Hon #9 samples. Adsorption curves can be defined by the Langmuir equation below. (See Table 5 for the coal sample Langmuir isotherm coefficients expressed on a dry, ash free basis.)

$$V=V_L \times P/(P + P_L)$$

The Langmuir equation indicates the maximum volume of methane (V) that the coal can hold at various reservoir pressures (P). V_L and P_L are the Langmuir volume and pressure coefficients, respectively. Volumes are in scf/ton and pressures are in psi units. When the Langmuir volume, measured at the pressure of the coal reservoir, is divided by the gas content value of that reservoir coal, the result provides a measure of methane gas saturation. The curves can also be used to calculate the pressure reduction needed to begin producing gas and the potential recovery amounts. In the Hon #9 the moderate to marginally low methane saturations vary from 42 to 64%. Gas saturations of the shales range from 40 to 74%.

Table 5. Coal Isotherm data, Hon #9 well.

Sample lab No.	Coal seam or shale-sample number	Depth (ft)	Langmuir coefficients (daf)		Gas storage capacity at reservoir pressure (scf/t, daf)	Gas saturation at reservoir pressure (%)
			V_L(scf/t)	P_L (psia)		
HON-D1	Danville-1	756.2	574	865.5	157.6	58.4
HON-D2	Danville-2	759.7	474.4	740.9	145.9	64.3
HON-D3	Herrin-1	803.5	513	779.8	158.3	53.1
HON-D4	Herrin-2	805	523.8	786.4	160.9	56.3

HON-D5	Herrin-3	807	517.3	781.8	159.8	52.2
HON-E1	Turner Mine Shale	874	617.4	871.7	186.9	40.1
HON-E2	Springfield-1	880.8	525.8	764.1	175.1	43.4
HON-E3	Springfield-2	882.7	508	795.6	164.9	51.1
HON-E4	Springfield-3	883.7	520.6	739.6	177.5	45.9
HON-E5	Excello Shale	967.4	553.9	887.3	177.6	50.2
HON-C2	Houchin Creek	968.7	376.1	583.2	157.3	42.1
HON-C3	Survant-1	993.9	397.5	526.8	178.7	51.2
HON-C4	Survant-2	994.7	418.1	621.2	171.2	52.2
HON-C5	Survant-3	996.4	383.7	594.0	161.4	52.7
HON-A1	Mecca Quarry Shale	1058	187.4	637.4	78.4	73.9
HON-A3	Dekoven	1062.5	402.6	507.0	191.5	47.7
HON-A4	Davis-1	1107.5	429.8	486.7	213.3	53.9
HON-A5	Davis-2	1111.3	484.8	496.7	238.6	45.3
HON-B1	Davis-3	1113.7	395.7	518.6	190.7	43.9

Permeability Testing- Pressure transient well tests have been completed at the Hon #9 and #3 wells by Pinnacle Technologies, Denver, Colorado (see Table 6). Selected coal intervals were perforated with 4 shots per foot. Individual coals were isolated by movable packers and plugs. We tested six coals in the Hon #9, the cored well that will become the center of the pilot. Coal permeabilities derived from these injection-falloff tests in the Hon #9 range from 3 to 34 millidarcies. No damage to the near-borehole environment by drilling or casing cement was detected (as evidenced by a negative skin factor).

Our testing program also evaluated two coal zones in the Hon #3 well, a plugged deep oil well that was re-completed in the coals as a possible dewatering well for our pilot. We wanted to see if an old well could be salvaged for methane production. Initial tests in the Hon #3 had instrument failures. Subsequent re-tests yielded unusually low perm (1mD) in the Herrin Coal and unusually high perm (261mD) in the Springfield Coal. We are discussing these tests with other engineers to evaluate the two anomalous results.

Table 6. Injection-Falloff Test Analysis Summary

Hon #9

Coal	Perforated Interval Top (ft)	Base (ft)	Net Thickness (ft)	Permeability (mD)	Skin Factor (dimensionless)
Danville	759	761	2	33.7	n/a
Herrin #6	805	810	5	4.3	-4.9
Springfield #5	882	886	4	21.7	-1.8
Survant	996	1000	4	3.3	-5
Dekoven	1066	1068	2	10.6	-3.4

Davis	1109	1116	5	14.1	-0.3

Hon #3

Coal	Perforated Interval Top (ft)	Base (ft)	Net Thickness (ft)	Permeability (mD)	Skin Factor (dimensionless)
Herrin #6	814	818	4	0.99	25.8
Springfield #5	892	896	4	261	-5.1

Organic Petrography- Maceral and vitrinite reflectance analyses of samples from the Hon #9 well were performed by the organic petrographer at the Indiana Geological Survey (see Table 7). These analyses describe the types of organic matter present, their relative amounts in the coal, and the average reflectance of light from the vitrinite particles, a measure of thermal maturity. Methane adsorption varies with the maceral composition and maturity. Average vitrinite reflection values (Ro) for our coals ranged from 0.53% to 0.61% with no significant variation with increasing depth over the limited vertical section in which they occur. Maceral content of the coal samples ranged from 67 to 89% vitrinite, 2 to 14% liptinite, 3 to 18% inertinite, and <1 to 18% mineral matter.

Table 7. Vitrinite Reflectance and Maceral Content, #9 Hon Coals

by Maria Mastalerz, Indiana Geol Survey, June 2004

Sample lab No.	Coal seam (or shale)-sample number	Depth (ft)	Ro %	Vitrinite %	Liptinite %	Inertinite %	Mineral Matter %
HON-D1	Danville-1	756.2	0.55	81.8	4.2	8.2	5.8
HON-D2	Danville-2	759.7	0.55	74.0	4.0	3.8	18.2
HON-D3	Herrin-1	803.5	0.59	84.2	3.4	6.4	6.0
HON-D4	Herrin-2	805	0.57	89.4	3.0	6.8	0.8
HON-D5	Herrin-3	807	0.6	87.0	1.8	5.6	5.6
HON-E1	Turner Mine Shale	874	-				
HON-E2	Springfield-1	880.8	0.58	84.8	3.6	8.4	3.2
HON-E3	Springfield-2	882.7	0.58	86.0	4.4	9.2	0.4
HON-E4	Springfield-3	883.7	0.61	76.8	4.0	18.4	0.8
HON-E5	Excello Shale	967.4	-				
HON-C2	Houchin Creek	968.7	0.53	86.2	4.6	2.8	6.4
HON-C3	Survant-1	993.9	0.57	75.0	8.4	9.4	7.2
HON-C4	Survant-2	994.7	0.56	77.6	4.0	14.0	4.4
HON-C5	Survant-3	996.4	0.57	67.0	14.0	15.6	3.4
HON-A1	Mecca Quary Shale	1058	-				
HON-A3	Dekoven	1062.5	0.55	77.0	3.8	5.2	14.0
HON-A4	Davis-1	1107.5	0.58	76.0	6.6	10.0	7.4
HON-A5	Davis-2	1111.3	0.56	75.8	4.0	9.6	10.6
HON-B1	Davis-3	1113.7	0.56	80.8	4.4	6.8	8.0

Production Testing- ISGS has been pumping water from the Hon #9 since late June in order to remove coal fines and improve near-wellbore permeability. Water production began slowly with abundant coal fines. Initially, the well could be pumped dry in one day. Since mid- August the Hon #9 well has steadily produced about 12 barrels of

water per day and declining amounts of coal fines. Water produced in mid- August, 2004, had a salinity of 23,000 ppm total dissolved solids, a value confirmed in a subsequent sample taken two weeks later that we consider indicative of the pre-drilling, uninvaded reservoir fluid.
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Near the end of September, methane gas was found in the annular casing space. This gas was flared, but in a strong wind, we could not keep a flame at the flare, so the flow rate was low, perhaps 1 or 2 mcfpd, and not sustained. To get any measureable gas flow from a single, stand-alone well like this (not isolated from the surrounding infinite-acting coal seam aquifer) can be taken as a positive sign. A pressure meter has been recently installed to monitor the casing head methane build-up. The pressure has gradually increased from about 2 psi to 5 psi in about two weeks.

In late October we plan to inject and swab a clean-up fluid flush treatment in the Hon #9 well. This will consist of injecting about 100 barrels of clean saline formation water containing a surfactant, a deflocculent and an iron sequestering agent. Then, we will forcefully swab the water out of the well to remove additional coal fines and open the cleats to water and gas flow. This may provide sufficient stimulation to improve coal effective permeability so that it can be more rapidly dewatered. We will defer applying further stimulation techniques or drilling the remaining three dewatering wells until we evaluate the results of these flushing efforts. If unsuccessful, we plan to hydraulically fracture the well.

Planning, however, for drilling the remaining three dewatering wells has begun. Locations have been identified on a 20-acre spacing and the applications for drilling permits will be filed in the next quarter. Hopefully, drilling will be warranted and can proceed during the next quarter, as well.

Howard Energy, Wasem #C-1 well

The Howard Energy, Wasem #C-1 well, our second gas content well, was spud on July 21, 2004. The well is located in southeastern White County, Illinois, and reached a TD of 1030'. Eleven 20' cores were recovered that resulted in 27.5 net feet of coal from ten seams (Table 8), from which 15 coal samples and 2 black shale samples were taken for gas desorption analyses. An additional 6.5' of coal in four seams were identified from logs, resulting in a total of 34' of net coal in this well. The samples have been desorbing gas for over two months and we plan to continue desorption until the first week in November, 2004.

Table 8. Coal Tops from Howard Energy #C-1 well log and actual coal core thicknesses

Coal	Top (ft)	Base (ft)	Thickness (ft)	Core coal thickness (ft)
Danville	387	389.5	2.5	2.4
Unnamed coal	402	404	2	n/a
Herrin #6	449	456	7	7.2
#5a	475.5	477	1.5	n/a
Springfield #5	542	547	5	5.2
Houchin Creek #4	603.5	605	1.5	1.9
Survant #3	645.5	647	1.5	1.7
Colchester #2	698.5	699	0.5	0.3
U. Davis/L. Dekoven?	807	808.5	1.5	1.3
Davis	816	820	4	4.6
U. Mt. Rorah	886.5	888	1.5	1.2
L. Mt. Rorah	898.5	900	1.5	1.7
Unnamed coal	932	933	1.0	n/a
Murphysboro	966	968	2.0	n/a
TOTAL			33.0	27.5

Successive gas samples were taken from each canister for chemical and isotope composition analyses. The results are shown in Table 9 and the plots below. Methane quantities increase with successive samples, largely reflecting the dilution of headspace gas with coal gas over time. True formation methane gas is likely to be richer in methane than shown here.

The nitrogen values have been corrected to compensate for atmospheric nitrogen in the canister headspace and lines. The entire O2 and the portion of N2 that balances O2 in atmospheric air were subtracted from the canister gas sample values. However, the nitrogen value may not be fully corrected because an unknown quantity of air contaminant O2 may have been consumed by oxidation of the coal. Its companion atmospheric nitrogen would remain unaccounted for and not be subtracted from the total N2 content. Thus, N2 originally adsorbed on the coal in the subsurface is probably less than the value reported here due to undercounting the atmospheric correction.

The isotope data (Figs 5 & 6) imply that the desorbed gas is of biogenic origin.

Table 9

Wasem#C-1 well

Canister-gas sample No.	Coal or shale core	Core depth (ft)	Gas sampling		Gas composition, vol%					CH_4 isotope values	
			Date	Time	N_2	CO_2	CH_4	C_{2+}	$CH_4 + C_{2+}$	$\delta^{13}C_{CH4}$ (PDB)	δD_{CH4} (VSMOW)
C1-1	Danville 1	386.7	7/28/04	13:31	9.45	2.57	86.42	1.56	88.0	-68.4	-220.6
C1-2	Danville 1	386.7	8/2/04	14:53	7.59	2.84	89.54	0.04	89.6	-67.8	-224.5
C1-3	Danville 1	386.7	8/24/04	9:39	0.48	2.85	96.50	0.17	96.7	-66.8	
C2-1	Danville 2	387.7	7/28/04	13:41	13.66	2.13	84.09	0.13	84.2	-68.4	-222.4
C2-2	Danville 2	387.7	8/2/04	15:07	10.75	2.67	86.56	0.03	86.6	-68.3	-219.5
C2-3	Danville 2	387.7	8/24/04	9:46	8.36	2.62	88.95	0.06	89.0	-68.0	
C3-1	Herrin 1	450	7/28/04	13:47	16.02	2.38	81.37	0.23	81.6	-69.7	-221.8
C3-2	Herrin 1	450	8/2/04	15:13	13.73	2.56	83.47	0.23	83.7	-69.5	-219.8
C3-3	Herrin 1	450	8/24/04	9:52	7.03	2.57	90.13	0.27	90.4	-69.3	
C4-1	Herrin 2	451	7/28/04	13:54	16.23	2.40	81.14	0.24	81.4	-69.1	-218.5
C4-2	Herrin 2	451	8/2/04	15:19	11.92	2.57	85.30	0.21	85.5	-69.0	-221.9
C4-3	Herrin 2	451	8/24/04	9:57	9.67	2.41	87.69	0.24	87.9	-68.8	
C5-1	Herrin 3	453.8	7/28/04	14:03	15.13	2.27	82.58	0.02	82.6	-68.5	-215.1
C5-2	Herrin 3	453.8	8/2/04	15:23	10.62	2.10	87.28	0.00	87.3	-68.5	
C5-3	Herrin 3	453.8	8/24/04	10:02	4.70	2.39	92.92	0.00	92.9	-68.2	
D1-1	Sprinfield 1	532.1	7/28/04	14:17	16.44	1.67	81.18	0.71	81.9	-69.7	-215.6
D1-2	Sprinfield 1	532.1	8/2/04	15:43	16.57	1.63	77.66	4.14	81.8	-69.6	-217.7
D1-3	Sprinfield 1	532.1	8/24/04	10:16	12.05	1.78	85.36	0.82	86.2	-69.4	
D2-1	Sprinfield 2	533.1	7/28/04	14:23	10.59	1.72	86.70	0.99	87.7	-69.7	-215.8
D2-2	Sprinfield 2	533.1	8/2/04	15:49	9.96	1.88	86.96	1.20	88.2	-69.7	-213.6
D2-3	Sprinfield 2	533.1	8/24/04	10:17	5.74	1.91	91.03	1.32	92.3	-69.2	
D3-1	Sprinfield 3	535	7/28/04	14:30	18.73	1.71	78.50	1.07	79.6	-70.5	-217.9
D3-2	Sprinfield 3	535	8/2/04	15:52	17.26	1.97	79.67	1.09	80.8	-74.3	-215.4
D3-3	Sprinfield 3	535	8/24/04	10:22	13.48	1.85	83.46	1.21	84.7	-70.1	
D4-1	Houchin Creek	603.6	7/28/04	14:37	30.48	1.20	67.85	0.47	68.3	-70.7	-210.1
D4-2	Houchin Creek	603.6	8/2/04	15:57	30.34	1.30	67.90	0.46	68.4	-70.6	
D4-3	Houchin	603.6	8/24/04	10:31	23.03	1.44	74.99	0.54	75.5	-70.6	

	Creek										
D5-1	Survant	644	7/28/04	14:43	21.86	1.21	76.90	0.02	76.9	-71.4	-202.3
D5-2	Survant	644	8/2/04	16:00	16.77	1.36	81.85	0.02	81.9	-71.2	
D5-3	Survant	644	8/24/04	10:33	10.55	1.38	88.03	0.05	88.1	-70.9	
E1-1	Davis 1	808	7/28/04	13:46	31.45	2.14	66.41	0.00	66.4	-72.7	-209.2
E1-2	Davis 1	808	8/2/04	16:13	28.46	2.37	69.16	0.01	69.2	-73.0	-206.9
E1-3	Davis 1	808	8/24/04	10:45	18.68	2.31	79.01	0.00	79.0	-72.1	
E2-1	Davis 2	816.8	7/28/04	14:03	24.31	1.63	74.06	0.00	74.1	-72.2	-208.1
E2-2	Davis 2	816.8	8/2/04	16:17	19.05	1.75	79.20	0.00	79.2	-72.1	-210.0
E2-3	Davis 2	816.8	8/24/04	10:51	12.06	1.82	86.13	0.00	86.1	-71.8	
E3-1	Davis 3	818.3	7/28/04	15:10	29.01	1.63	69.37	0.00	69.4	-72.1	-209.3
E3-2	Davis 3	818.3	8/2/04	16:19	23.22	1.77	75.01	0.00	75.0	-72.2	-211.4
E3-3	Davis 3	818.3	8/24/04	10:55	15.40	1.76	82.83	0.00	82.8	-72.1	
E4-1	Mt. Rorah 1	887.3	7/28/04	15:17	44.21	1.38	53.35	1.06	54.4	-71.6	-200.3
E4-2	Mt. Rorah 1	887.3	8/2/04	16:24	44.52	1.27	53.06	1.14	54.2	-71.1	
E4-3	Mt. Rorah 1	887.3	8/24/04	11:01	40.76	1.53	56.50	1.20	57.7	-70.8	
E5-1	Mt. Rorah 2	899.2	7/28/04	15:22	43.23	1.23	54.41	1.13	55.5	-70.6	-196.3
E5-2	Mt. Rorah 2	899.2	8/2/04	16:27	41.67	1.23	55.89	1.20	57.1	-70.6	
E5-3	Mt. Rorah 2	899.2	8/24/04	11:05	37.11	1.52	60.11	1.27	61.4	-70.5	
F12-1	Excello Shale	601	8/2/04	16:40:00	36.89	0.32	62.14	0.66	62.8	-70.3	
F12-2	Excello Shale	601	8/24/04	11:12:00	23.84	0.68	74.68	0.81	75.5	-69.5	
F13-1	Mecca Quarry Shale	696.5	8/2/04	16:48:00	57.61	0.40	41.94	0.05	42.0	-75.3	
F13-2	Mecca Quarry Shale	696.5	8/24/04	11:18:00	45.21	0.87	53.84	0.08	53.9	-74.8	

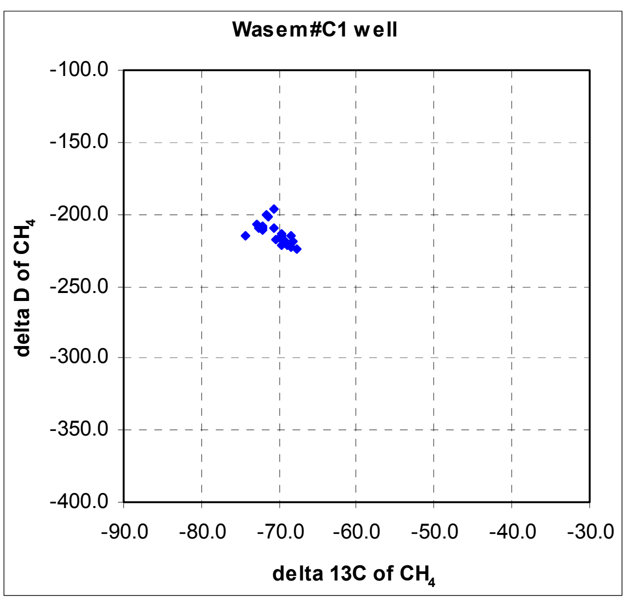

Figure 5. Cross-plot of delta D vs. delta 13C for Wasem #C-1 coal gas methane

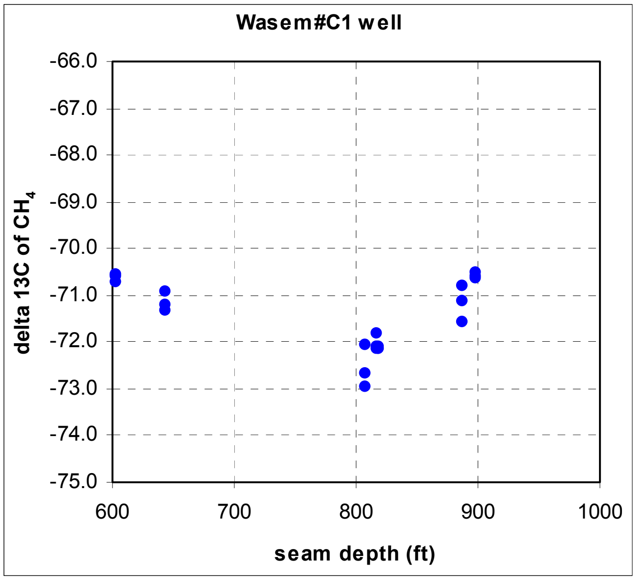

Figure 6. Cross-plot of delta 13C vs. depth for Wasem #C-1 coal gas methane

Three samples taken from our third round of desorbed gas samples were analyzed (Table 10) by an outside lab in order to measure the amount of H2. Faraj and Hatch, 2004, indicated that large amounts of H2, up to 30% or so, may form in canisters by microbial activity and that this could effect the prediction of gases from a coal. Our hydrogen content is very low so this is not a problem for the coal samples of Illinois coals or the gas measurement techniques we use. We also used highly evacuated sample containers here to test if we were getting some gas contribution from the standard vacutainers we used for sampling. Again, we saw no difference in gas composition by varying the vacuum.

Table 10. ISOTECH GC ANALYSES (vol%) *

	CO2	O2 +Ar	N2	C1	C2	C3	iC4	nC4	iC5	nC5	C6+
C2-3 DANVILLE 2	2.44	0.82	11.88	84.62	0.03	0.04	0.015	0.004	0.25	0	0.28
C4-3 HERRIN 2	2.33	0.18	11.16	85.52	0.254	0.04	0.004	0.003	0	0	0.002
D3-3 SPRINGFIELD 3	1.78	0.43	15.89	80.23	0.94	0.44	0.055	0.059	0.012	0.003	0.005

	He	**H2**	CO	specific gravity	BTU per 1000 scf
C2-3 DANVILLE 2	0	0.155	0	0.632	861
C4-3 HERRIN 2	0	0.509	0	0.623	874
D3-3 SPRINGFIELD 3	0.0015	0.152	0	0.65	846

*This Isotech data has not been corrected for air contamination in the canister headspace or feed lines.

Future Drilling- The third ISGS core well is planned for a location in Jasper County, Illinois where the coal is the deepest in the basin and the net coal thickness is very high. We have entered into negotiation with an operator, plan to stake the well in October, and begin drilling it as soon as we get Year 2 funds from U.S. DOE. The delay in DOE's funding will put us behind by two to three months on this phase of the project.

We plan to drill three dewatering wells in our pilot production area in the second year of our study. Costs for these wells will be shared by our industry partner, Royal Drilling, and by our research grant from the State of Illinois.

Mapping- Coal cleat orientation data had been received from Kentucky and Indiana and has been merged with Illinois data. ISGS has completed a basin-wide map of the coal cleat data.

Workshop- A multi-day Illinois Basin Coalbed Methane Symposium was held November 16 and 17, 2004, in Evansville, Indiana. This was for both experienced coal gas explorers, as well as those curious about coal bed methane in the Illinois Basin. The Midwest PTTC Regional Office, located at the Illinois State Geological Survey organized the program, and arranged publicity and logistics. The technical program included a geological and an engineering expert who described the principals of coal gas exploration and production in detail. A geochemist reviewed coal desorption analyses. A Halliburton engineer described successful stimulation and completion of Illinois and Indiana coal gas wells. The three state Geological Surveys presented available data and reviewed industry activity in their states. Two operating companies that are developing coal gas fields discussed their experiences thus far.

Reference

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Indiana

In Indiana, project efforts acquired and processed structural and thickness data for the coal beds that have not been previously examined. For these seams, the croplines as well as maps of the thickness and depth were generated. Coal thickness mapping was done for the following seams: Houchin Creek, Danville, Springfield, Hymera, and Seelyville (Figures 7, 8 and 9). Each map was contoured using the available data. Thickness values smaller than 18 inches were filtered out from the analysis. Mined-out areas were not considered in this initial assessment. A 1 km^2 grid was created for each data set and these grids were added to obtain a cumulative thickness coal map for the area. In cooperation with our project partner, Black Beauty Coal Company, coal cores from the Springfield and the Seelyville in Gibson and Sullivan Counties were obtained and have been completely desorbed. Adsorption isotherm data was also been obtained for selected coal samples.

Using the geothermal data available from the AAPG geothermal Survey of North America, a new interpretation for the geothermal gradient map was produced. Data points that seemed anomalous (too high or too low) were filtered out by examination of nearby data points.

Table 11 – Adsorption isotherm data for selected Indiana coal samples.

Sample	Coal	County	depth (feet)	Adsorption of gases (scf/ton, daf basis)					
				CO2 at	CO2 at	CH4 at	CH4 at	CO2/CH4 at	CO2/CH4 at
				300 psi	400 psi	300 psi	400 psi	300 psi	400 psi

Dan C1	Danville	Vigo	surface mine	625	700	170	202	3.7	3.5
Dan A3	Danville	Knox	undergr. mine	715	788	147	175	4.9	4.5
Vic-1	Springfield	Sullivan	373	540	640	195	225	2.8	2.8
Spr Cy	Springfield	Warrick	surface mine	619	727	115	142	5.4	5.1
Wabash	Springfield	Gibson	undergr. mine	680	785	157	188	4.3	4.2
Vic-1	Seelyville	Sullivan	556	521	602	175	215	3.0	2.8
Seel SDH	Seelyville	Posey	901	577	681	102	128	5.7	5.3
33-H8 448.7	Seelyville	Gibson	448.7	684	770	196	234	3.5	3.3
33-H8 452.5	Seelyville	Gibson	475.3	655	740	200	235	3.3	3.1
UB B1	Upper Block	Parke	surface mine	523	561	102	128	5.1	4.4
UB B2	Upper Block	Parke	surface mine	572	624	134	160	4.3	3.9
UB I5	Upper Block	Daviess	234	nd	nd	123	150	nd	nd
LB I5	Lower Block	Daviess	251	nd	nd	127	150	nd	nd

Table 12 – Gas content data for Indiana coals

CBM#1 GC-04-153, Gibson County, Indiana

Coal sample	Depth in feet	Desorbed plus lost scf/ton, air-dry	Residual scf/ton, air dry	Res. (daf)	**Total gas scf/ton, air dry**	**Total gas scf/ton, daf**
Springfield 12	485.5-486.5	98.5	7.4	9.0	**105.9**	**128.6**
Springfield 13	489.1-490.1	88.6	20.1	24.5	**108.7**	**132.8**
				Average	**107.3**	**130.7**
Houchin Creek 7	573-574	22.2	7.9	10.6	**30.1**	**40.4**
Houchin Creek 14	574-575	7.3	2.5	3.4	**9.8**	**13.5**
				Average	**20.0**	**27.0**
Seelyville 18	700-701	20.3	not measured			

CBM-2 25-2S-12W, Gibson County, Indiana

Coal	Depth in feet	Desorbed plus lost scf/ton, air-dry	Residual scf/ton, air dry	Res. (daf)	**Total gas scf/ton, air dry**	**Total gas scf/ton, daf**
Danville 32	412-413	40	not measured			
Seelyville 20	780.8-	101.4	14.2	18.9	**115.6**	**153.6**

	781.8					
Seelyville 21	781.8-782.1	41.9	9.7	17.1	**51.6**	**91.2**
Seelyville 33	782.8-783.8	19	1	1.5	20	30.8
Seelyville 23	783.4-784.8	45.1	9.3	11.8	54.4	69.0
Seelyville 29	784.8-785.8	20.5	4.4	5.6	24.9	31.8
Seelyville 31	785.8-786.8	81.1	13	22.0	94.1	159.0
				Average	**60.1**	**89.2**

Knox IGS-2004-K1, Knox County, Indiana

Coal	Depth in feet	Desorbed plus lost scf/ton, air-dry	Residual scf/ton, air dry	Res. (daf)	**Total gas scf/ton, air dry**	**Total gas scf/ton, daf**
Colchester 24	590.4-591.4	15.5	18.6		34.1	140.6
Colchester 28	591.4-592.4	17.3	17.4		34.7	372.3
				Average		
Seelyville 25	611-612	78.2	13.4	22.0	91.6	150.3
Seelyville 26	612-613	99.3	20	27.2	119.3	162.0
Seelyville 27	613-614	32.4	1.8	2.8	**34.2**	**52.5**
Seelyville 30	614-615	88.1	17.6	23.6	**105.7**	**142.0**
				Average	**81.7**	**121.6**

Table 13 – Geochemical data for Indiana coals

CBM#1 GC-04-153, Gibson County, IN %, dry basis

Coal sample	Depth (feet)	Moisture (%)	Ash	Sulfur	BTU	R_o	V	L	I	MM
Springfield 12	485.5-486.5	11.86	4.95	0.78	13921	0.69	76.6	7.2	15.8	0.4
Springfield 13	489.1-490.1	12.5	4.83	0.74	13786	0.74	90	4.4	5.2	0.4
Houchin Creek 7	573-574	7.53	13.01	7.15	12622	0.6	76	4.8	10.4	8.8
Houchin Creek 14	574-575	8.64	15.82	3.10	12127	0.61	82.4	7.2	6	4.4
Seelyville 18	700-701	6.54	43.56	3.86	7812	0.57	62.8	3.6	9.6	24

CBM#2 25-2S-12W, Gibson County, IN

Danville 32	412-413	10.36	11.54	2.25	12820	0.58	83.2	8.8	4.8	3.2
Seelyville 20	780.8-781.8	8.85	12.66	4.03	12480	0.6	80	6.6	8.4	4.2
Seelyville 21	781.8-	6.26	33.18	2.42	9177	0.64	71.2	4.4	6.4	18.0

	782.1									
Seelyville 33	782.8-783.8	7.25	19.66	12.88	11349	0.6	63.8	7.8	13.6	18.8
Seelyville 23	783.4-784.8	7.69	9.65	5.51	13246	0.59	78	10.8	8.4	2.8
Seelyville 29	784.8-785.8	8.73	10.17	3.72	13132	0.59	81.2	6.4	10.4	2.0
Seelyville 31	785.8-786.8	6.46	29.25	4.81	10069	0.61	57	4.2	12	26.8

Knox IGS-2004-K1,
Gibson County, IN

Colchester 24	590.4-591.4	6.41	62.69	2.97	5031	0.57	42.8	3.6	7.6	46.0
Colchester 28	591.4-592.4	7.03	76.19	2.54	2717	0.58	27.6	13.2	1.2	58.0
Seelyville 25	611-612	8.38	25.92	4.84	9617	0.59	62.8	3.6	9.6	24.0
Seelyville 26	612-613	11.62	10.6	6.00	13053	0.57	72.6	5.2	6.1	16.1
Seelyville 27	613-614	9.24	18.31	10.60	11672	0.59	76	3.2	17.2	3.6
Seelyville 30	614-615	9.48	12.56	4.61	12550	0.6	69	5.8	18	7.2

Note: R_o - vitrinite reflectance (%), V - vitrinite, L - liptinite, I - inertinite, MM - mineral matter (volume %)

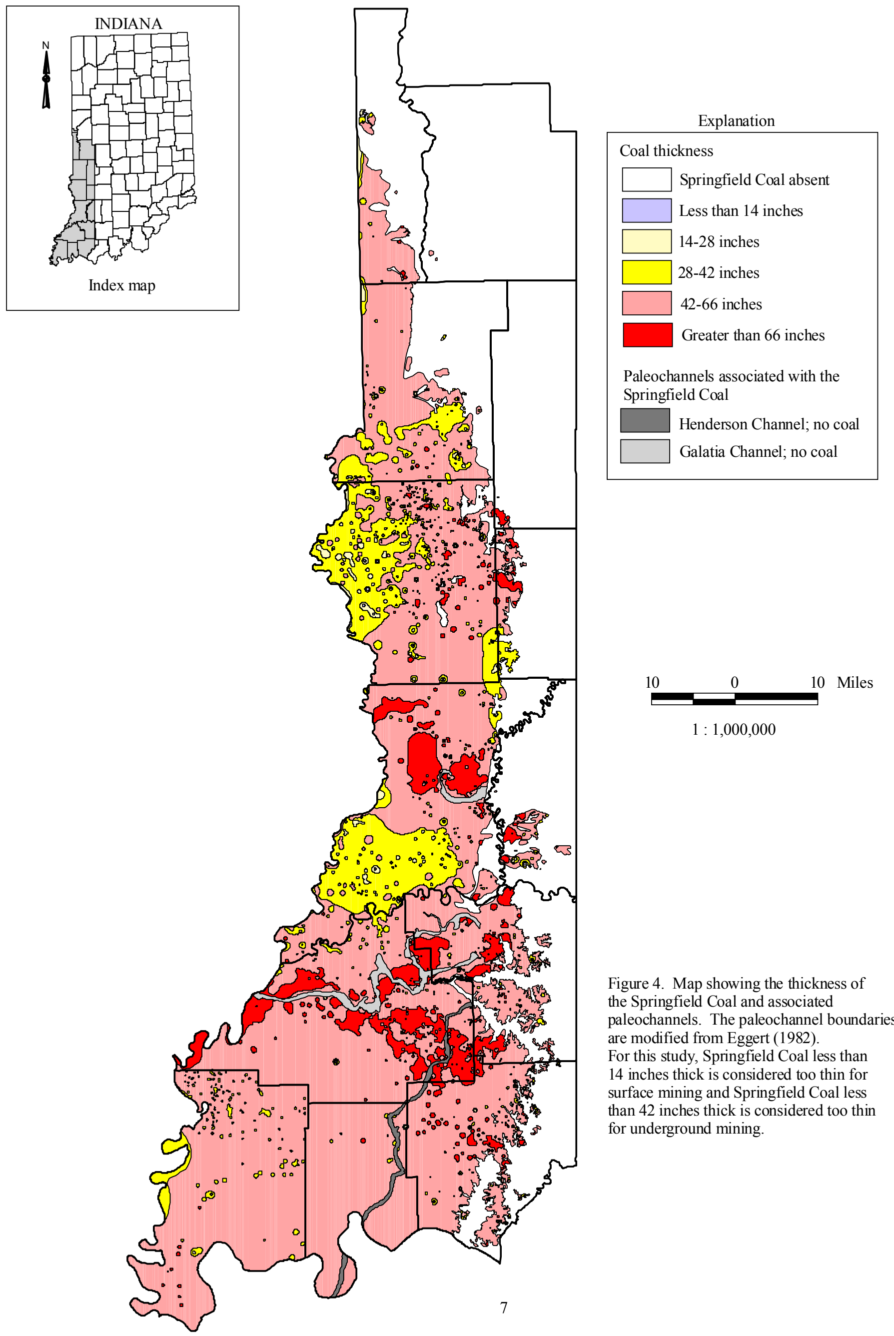

Figure 7 – Thickness of the Springfield coal bed in Indiana.

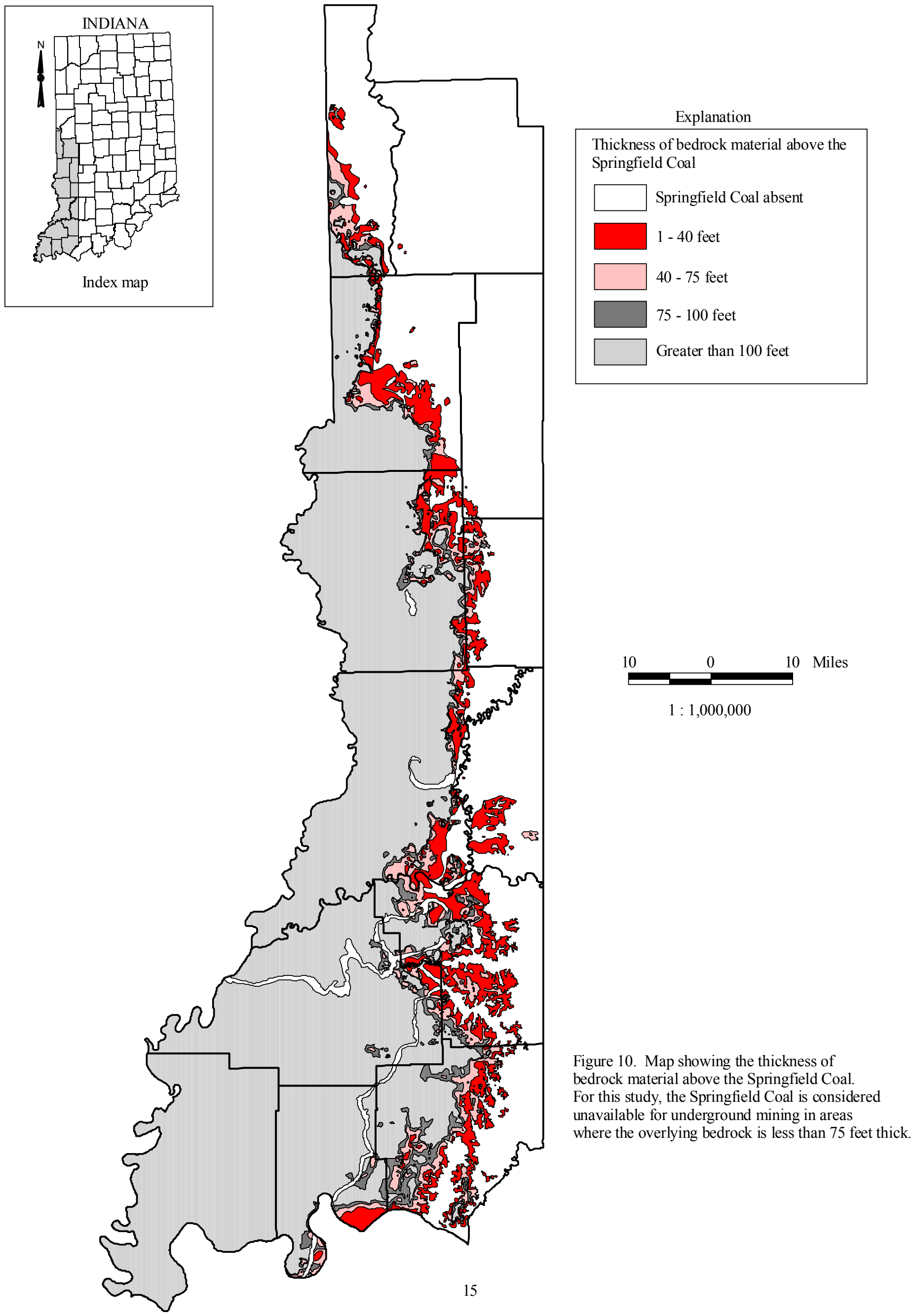

Figure 8 - Overburden thickness on the Springfield coal bed in Indiana.

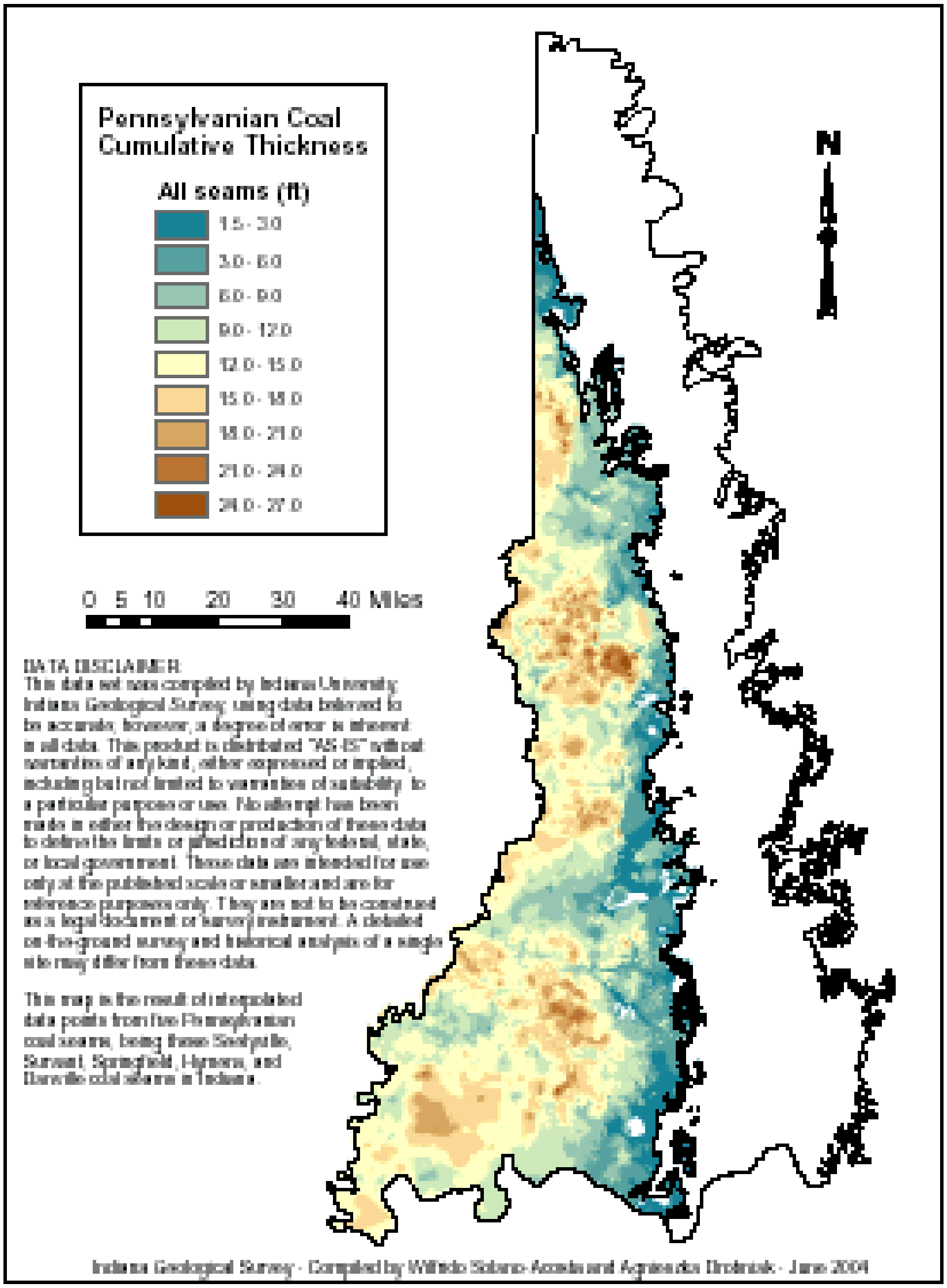

Figure 9 - Cumulative coal thickness (all coal beds) in Indiana.

Kentucky

In the Kentucky portion of the Illinois Basin, five wells were drilled, from which a total of 63 samples of coal and shale were collected for coal bed methane desorption. Drill hole locations were selected following the construction of detailed thickness and overburden maps for coal beds in the Carbondale and Shelburn Formations (Figs. 10 and 11). Coals in both of these formations tend to be the thickest and most laterally extensive within the Illinois Basin. Desorbed gas measurements were collected over a period of three to six months. When negligible gas contents were detected (i.e., the sample was finished desorbing) the entire core sample was reduced to a top size of -1mm using a large hammer mill crusher, and then placed back into the canister and resealed. Following this, measurements were

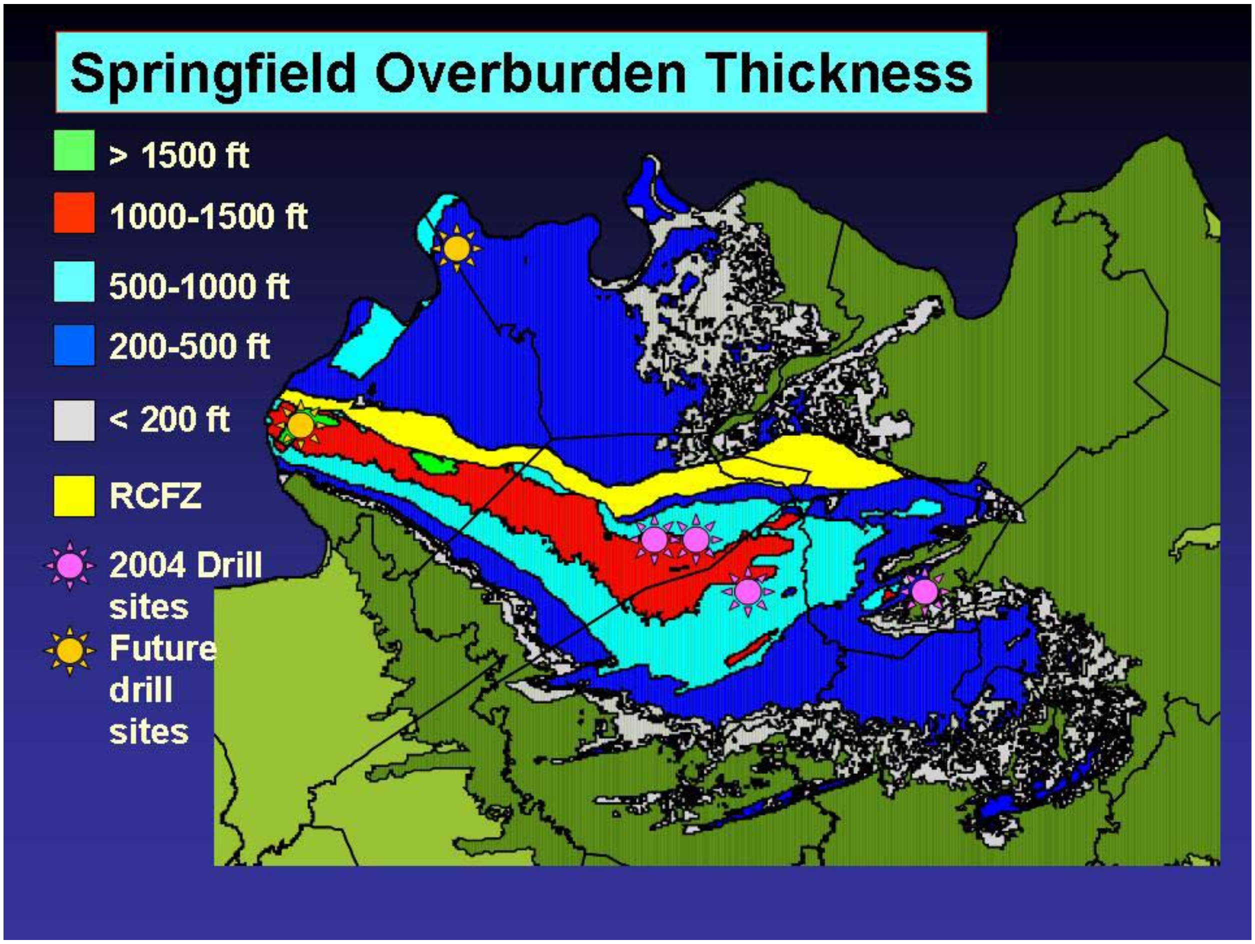

Figure 10 – Overburden thickness on the Springfield coal and drill core sites in western Kentucky

collected for another two to six weeks to record residual gas. A list of samples and their desorbed gas amounts is shown in Tables 12 and 13.

Gas samples were collected in 15 ml vaccutainers and sent to the Indiana University geochemical laboratories for species and origin analysis. Available analyses are shown in Table 14, with others pending completion. Sample analyses indicate a predominance of methane with minor amounts of heavier hydrocarbon gases. Nitrogen and carbon dioxide were not tested for.

Samples were submitted to RMB analytical laboratories in Vancouver, British Columbia, Canada for methane adsorption isotherm analyses, but results are currently unavailable. Standard geochemical analyses were performed at the Kentucky Geological Survey and are reported in Tables 14 and 15.

Individual Core Holes

DC-04-9 – This core hole was drilled in Webster County with a T.D. (total depth) of 1142.4 ft. Coal beds that were collected and desorbed include the WKY #13, WKY #10 and WKY #9 coal beds. A sample of the WKY #9 organic-rich roof shale was also sampled for gas content.

DC-04-10 – This core hole was also drilled in Webster County, with a T.D. of 1222.5 ft. Coal beds that were collected and desorbed include the WKY #13, WKY #10 and WKY #9 coal beds.
A sample of the WKY #9 organic-rich roof shale was also sampled for gas content.

Cumulative coal thickness for the western Kentucky No. 6, No. 7, No. 9, No. 11, No. 12, and No. 13 coals

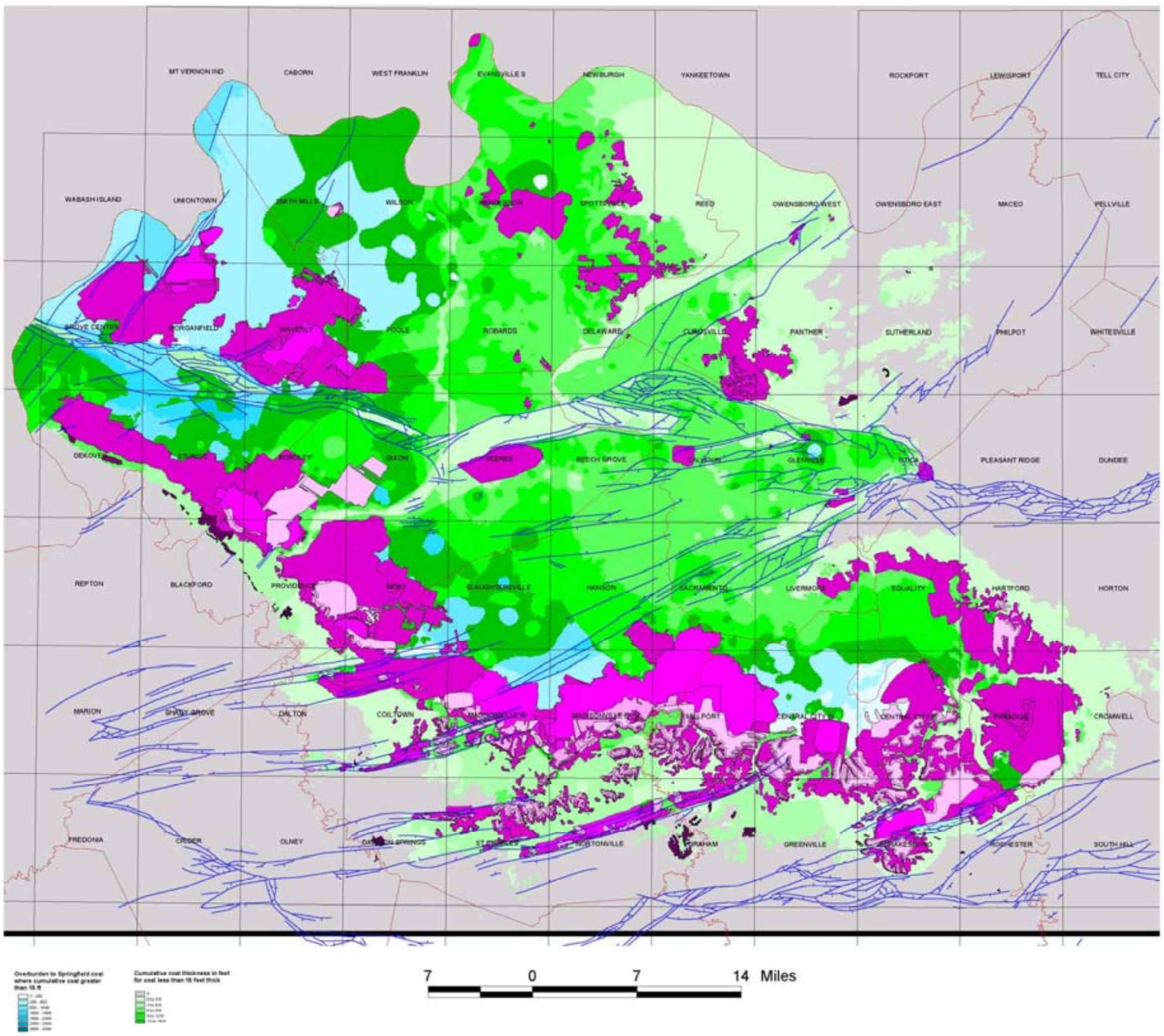

Figure 11 – Cumulative coal thickness map for major coal bed methane target coals (Carbondale and Shelburn Formations) in western Kentucky.

Big Run 1 – This core hole was drilled in Ohio County, on the eastern margin of the Western Kentucky Coal Field. One coal, the WKY #9, was sampled at a depth of 133.5 ft. This sample was primarily collected because of its shallow depth to provide a contrast with coals that were more deeply buried.

P-42 – This core hole was drilled in Hopkins County to a depth of 1009.8 ft. Coal beds that were collected and desorbed include the WKY #6 (Davis), WKY #8b (Colchester), WKY #9 (Springfield), and WKY #11 (Herrin). Roof shale samples of all four coals were also sampled.

PNG Young 1A - This core hole was drilled in Union County to a depth of 2006.1 ft. Coal beds that were sampled include the WKY #13 (Baker), WKY #11 (Herrin), WKY #10 (Paradise), WKY #9 (Springfield), WKY #8, WKY #7 (DeKoven), WKY #6 (Davis), WKY #5 (Bancroft) and WKY #4 (Mannington). This hole was only recently completed and desorption is still in progress. As such, results of these samples are not included in this report.

Discussion – Desorbed gas concentrations (raw basis) for sampled coal beds varied between 22.4 scf/ton for the WKY #13 (Baker) coal bed from core hole DC-04-10 and 332.4 scf/ton for the WKY #13 (Baker) coal from core hole DC-04-9. Although this may seem to be an odd discrepancy for two samples of the same coal, consider that the #13 coal in DC-04-10 was 1.9 ft thick, whereas the #13 from DC-04-9 was 5.1 ft thick. Shale samples (raw basis) that were collected varied between 13.1 scf/ton for the Colchester roof shale from core hole P-42 and 49.9 scf/ton for the WKY #9 roof shale from core hole DC-04-9 (Tables 13 – 16).

One thing apparent from the accumulated desorption data is that the values are much higher than indicated by historical data. This is most probably the result of allowing the samples to desorb over a long period of time (up to 6 months). Another interesting finding was that the residual gas contents were, on average, half that of the total gas content. This is probably a function of our modified technique, that being to crush and desorb the entire core, rather than using a small (and supposedly representative) sample to obtain residual gas concentrations. In any case, the high residual gas amounts indicate that the permeability of western Kentucky coals are low; this will probably require well completion (artificial fracturing), or horizontal drilling to obtain economic coal bed methane.

Gas Composition and Origin

Although gas analyses are not complete, available gas data indicate a predominance of methane, with reduced amounts of heavier gases (Table 17). Nitrogen and carbon dioxide are not uniformly reported due to analytical anomalies. In terms of gas origin, the samples analyzed thus far are mainly of thermogenic origin, an exception being the Big Run sample, which was dominantly of biogenic origin.

Coal Quality

All collected samples were tested for proximate analysis (moisture, fixed carbon, volatile matter contents and ash yield), total sulfur and calorific value. Results are shown in Tables 18 and 19. In general, gas contents are highest in the samples that are lowest in ash. There does not appear to be any relationship between total sulfur content and gas content.

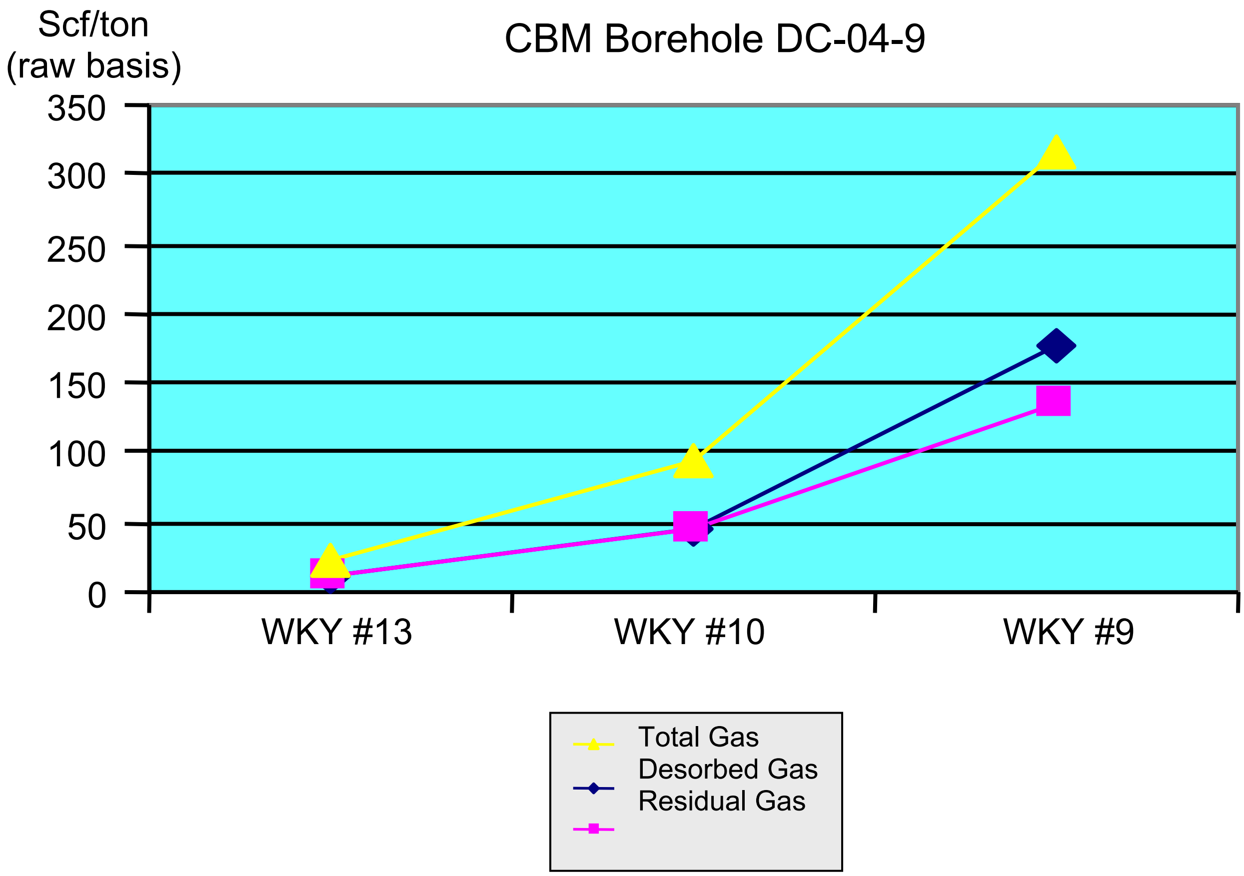

Figure 12 – Diagrammatic desorption data for western Kentucky coals from borehole DC-04-09.

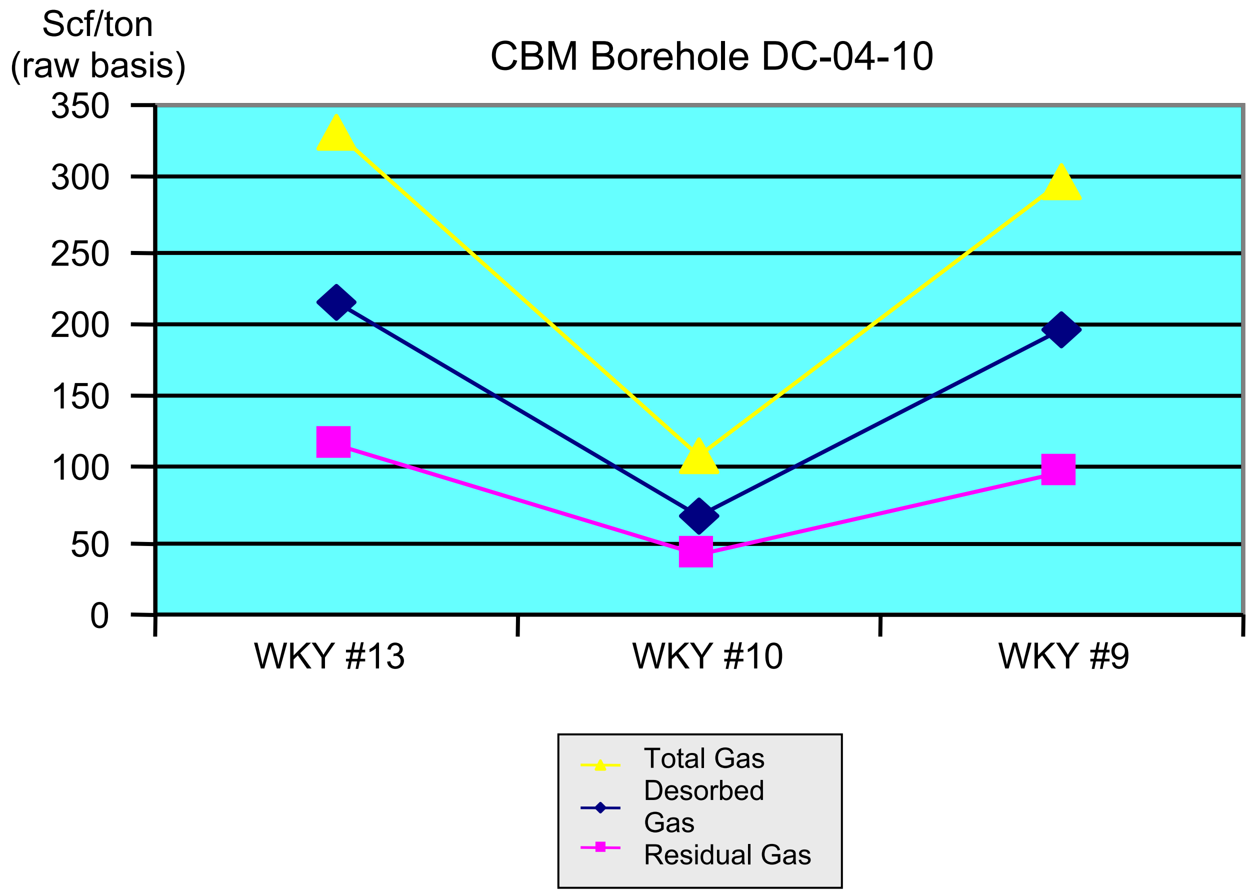

Figure 13 – Diagrammatic desorption data for western Kentucky coals from borehole DC-04-10.

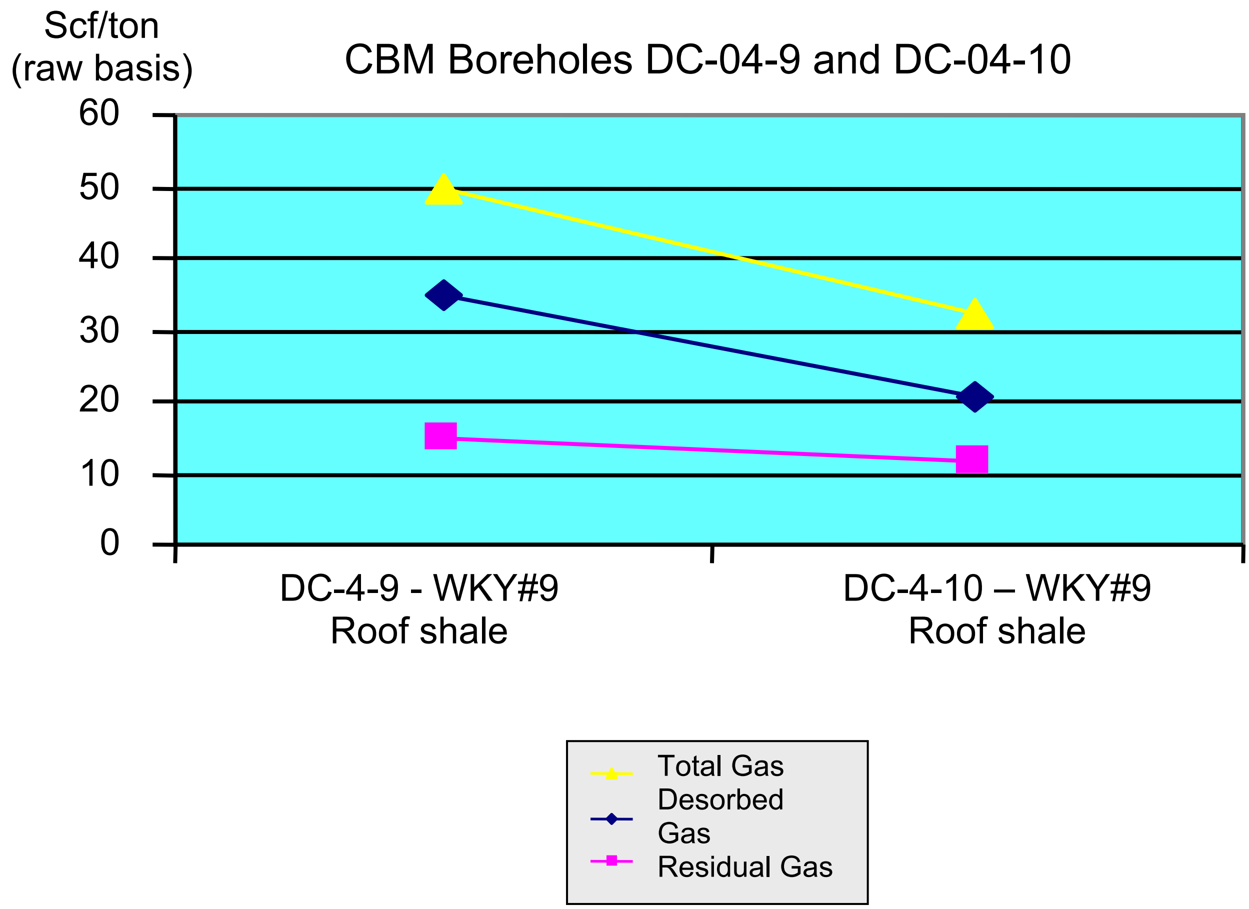

Figure 14 – Diagrammatic desorption data for western Kentucky shales from boreholes DC-04-09 and DC-04-10.

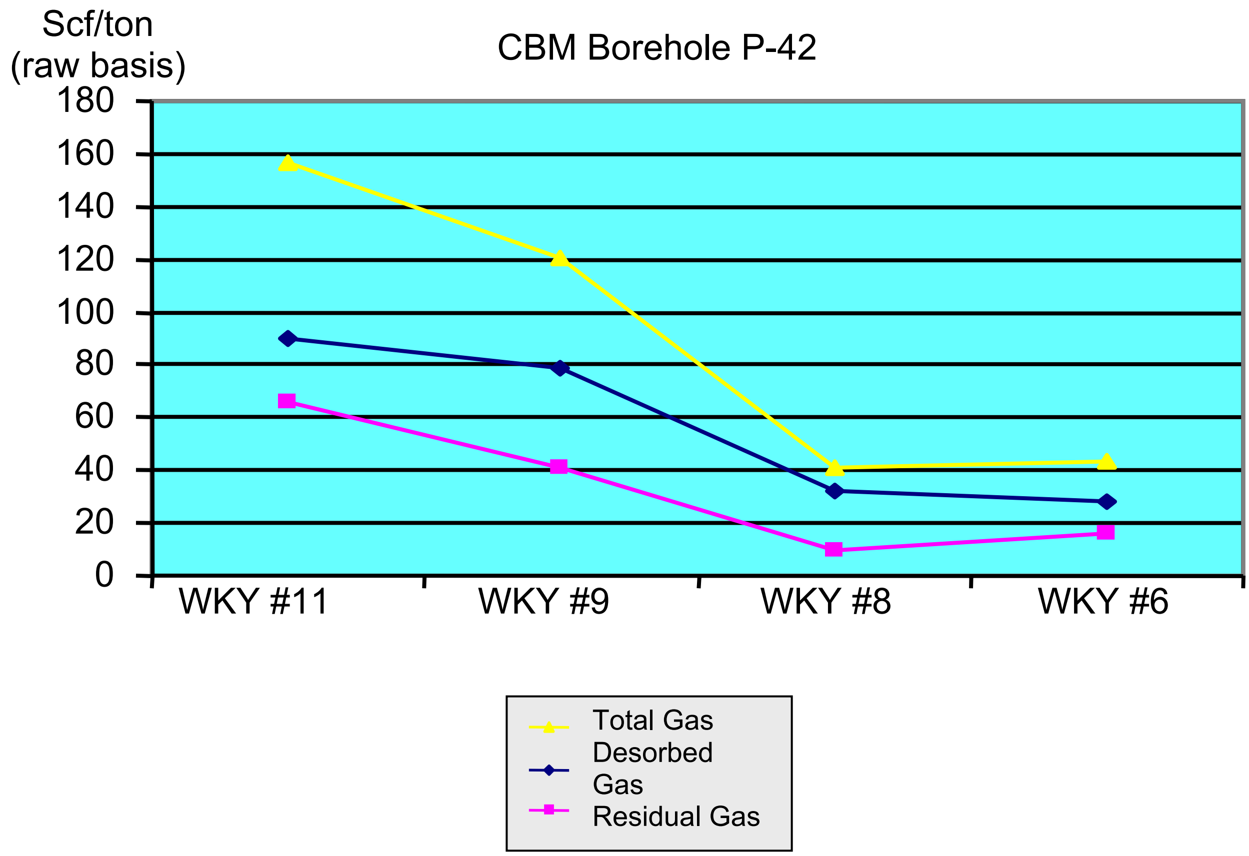

Figure 15 – Diagrammatic desorption data for western Kentucky coals from borehole P-42.

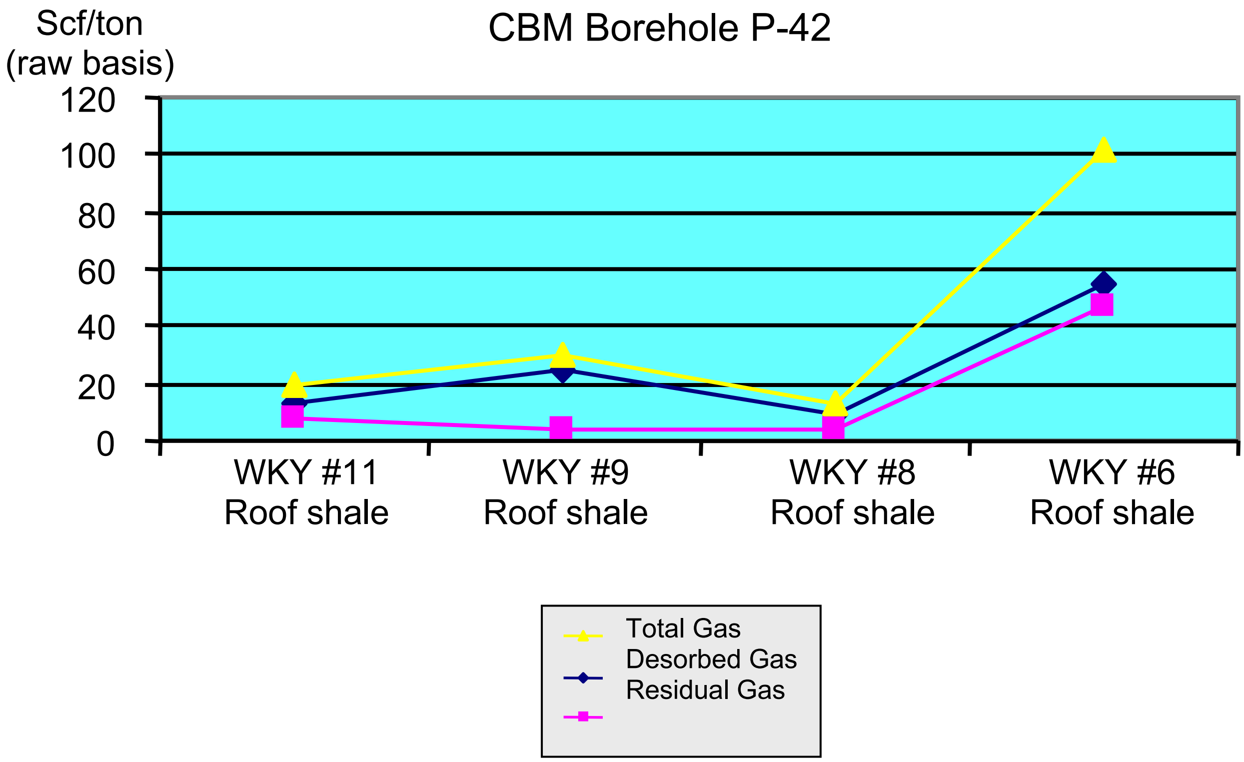

Figure 16 – Diagrammatic desorption data for western Kentucky shales from borehole P-42.

Core Run / Sample	Depth of sample (ft)	Cum. Gas desorbed (ml) whole core*	Cum. Gas desorbed (ml) crushed to - 1mm*	Total Gas desorbed (ml)	Raw total gas whole core Scf/ton	Raw total gas crushed Scf/ton	Raw total gas total Scf/ton
Ohio Co., KY							
BigRun1	133.5 to 136.8	2055.2	860.8	2916.00	30.55	14.08	44.63
Webster Co., KY							
DC-4-9 WKY13A	1013.9 to 1015.8	6631.8	3224.2	9856	61.01	32.55	93.56
DC-4-9 WKY13B	1015.8 to 1017.6	7427.3	3499.4	10926.7	79.47	40.59	120.06
DC-4-9 WKY13C	1017.6 to 1019	5159.8	3385.6	8545.4	73.44	45.34	118.78
DC-4-9 WKY13T	**1013.9 to 1019**	**19218.9**	**10109.2**	**29328.1**	**213.92**	**118.48**	**332.4**
DC-4-9 WKY10	1069.8 to 1071.6	5929.9	3449.7	9379.6	66.99	41.39	108.38
DC-4-9 WKY9RR	1137 to 1137.91	1717.5	343.9	2061.4	34.93	14.97	49.90
DC-4-9 WKY9A	1137.91 to 1139.91	8244.1	2578.8	10822.9	91.30	31.00	122.30
DC-4-9 WKY9B	1139.91 to 1141.79	3703.5	1687.3	5390.8	44.53	25.50	70.03
DC-4-9 WKY9C	1141.79 to 1142.38	1663.0	1034.00	2697	61.45	42.49	103.94
DC-4-9 WKY9T	**1137.91 to 1142.38**	**13610.6**	**5300.1**	**18910.7**	**197.28**	**98.99**	**296.27**
Webster Co., KY							
DC-4-10 WKY13	1086.8 to 1088.7	2240.0	1598.0	3838	12.67	9.74	22.41
DC-4-10 WKY10	1146.07 to 1148.12	5272.7	4888.3	10161	46.88	46.00	92.88
DC-4-10 WKY9RR	1137 to 1137.91	3142.4	1419.3	4561.7	20.66	11.90	32.56
DC-4-10 WKY9A	1217.92 to 1219.52	6492.4	3864.4	10356.8	73.46	45.67	119.13
DC-4-10 WKY9B	1219.52 to 1221.02	4894.8	3337.7	8232.5	59.63	44.23	103.86

DC-4-10 WKY9C	1221.02 to 1222.52	3992.3	3931.60	7923.9	45.34	47.09	92.43
DC-4-10 WKY9T	**1217.92 to 1222.52**	**15379.5**	**11133.7**	**26513.2**	**178.43**	**136.99**	**315.42**
		*Corrected for headspace volume					

Table 13 – Raw (as-received) gas contents for western Kentucky coal beds.

Core Run / Sample	**Depth of sample (ft)**	**Cum. Gas desorbed (ml) whole core**	**Cum. Gas desorbed (ml) crushed to -1mm***	**Total Gas desorbed (ml)**	**DAF total gas whole core Scf/ton**	**DAF total gas crushed Scf/ton**	**DAF total gas total Scf/ton**
BigRun1	133.5 to 136.8	2055.20	860.8	2916.00	37.99	17.51	55.50
DC-4-9 WKY13A	1013.9 to 1015.8	6631.8	3224.2	9856	76.26	40.69	116.95
DC-4-9 WKY13B	1015.8 to 1017.6	7427.3	3499.4	10926.7	99.34	50.74	150.08
DC-4-9 WKY13C	1017.6 to 1019	5159.8	3385.6	8545.4	91.80	56.68	148.48
DC-4-9 WKY13T	**1013.9 to 1019**	**19218.9**	**10109.2**	**29328.1**	**267.4**	**148.11**	**415.51**
DC-4-9 WKY10	1069.8 to 1071.6	5929.9	3449.7	9379.6	83.74	41.74	125.48
DC-4-9 WKY9RR	1137 to 1137.91	1717.5	343.9	2061.4	164.93	70.67	235.60
DC-4-9 WKY9A	1137.91 to 1139.91	8244.1	2578.8	10822.9	111.34	37.81	149.15
DC-4-9 WKY9B	1139.91 to 1141.79	3703.50	1687.3	5390.8	52.44	30.03	82.47
DC-4-9 WKY9C	1141.79 to 1142.38	1663.00	1034.00	2697	123.53	85.41	208.94
DC-4-9 WKY9T	**1137.91 to 1142.38**	**13610.60**	**5300.1**	**18910.7**	**287.31**	**153.25**	**440.56**

DC-4-10 WKY13	1086.8 to 1088.7	2240.0	1598.0	3838	23.04	17.71	40.75
DC-4-10 WKY10	1146.07 to 1148.12	5272.7	4888.3	10161	58.6	57.5	116.10
DC-4-10 WKY9RR	1137 to 1137.91	3142.4	1419.3	4561.7	49.20	28.34	77.54
DC-4-10 WKY9A	1217.92 to 1219.52	6492.4	3864.4	10356.8	89.58	53.29	142.87
DC-4-10 WKY9B	1219.52 to 1221.02	4894.8	3337.7	8232.5	72.72	53.94	126.66
DC-4-10 WKY9C	1221.02 to 1222.52	3992.3	3931.60	7923.9	55.29	57.43	112.72
DC-4-10 WKY9T	**1217.92 to 1222.52**	**15379.5**	**11133.7**	**26513.2**	**217.59**	**164.66**	**382.25**
		*Corrected for headspace volume					

Table 14 – Dry-ash-free (DAF) gas contents for western Kentucky coal beds

Core Run / Sample	Depth of sample (ft)	Cum. Gas desorbed (ml) whole core*	Cum. Gas desorbed (ml) crushed to -1mm*	Total Gas desorbed (ml)	Raw total gas whole core Scf/ton	Raw total gas crushed Scf/ton	Raw total gas total Scf/ton
P-42 WKY#11RR	665.5 to 673.77	3652.6	1818.3	5470.9	12.9	7.3	20.2
P-42 WKY#11A	673.77 to 675.65	6406.5	4119.7	10526.2	25.0	16.8	41.8
P-42 WKY#11B	675.65 to 677.55	8073.2	3130.0	11203.2	31.3	13.4	44.6
P-42 WKY#11C	677.55 to 678.88	3643.9	2820.4	6464.3	18.5	14.9	33.4
P-42 WKY#11D	678.88 to 680.18	942.7	1468.9	2411.6	15.5	21.0	36.6
P-42 WKY#11T	**673.77 to 680.18**	**19066.3**	**11539.0**	**30605.3**	**90.3**	**66.1**	**156.4**
P-42 WKY#9RR	782.1 to 784	6879.4	754.4	7633.8	25.4	4.5	30.0
P-42 WKY#9A	784.2 to 786.1	7954.7	3602.8	11557.5	27.8	14.9	42.7
P-42 WKY#9B	786.1 to 788.04	7654.8	3198.6	10853.4	28.3	12.9	41.2
P-42 WKY#9C	788.04 to 789.35	4558.7	2395.2	6953.9	23.0	13.3	36.3
P-42 WKY#9T	**784.2 to 789.35**	**20168.2**	**9196.6**	**29364.8**	**79.0**	**41.1**	**120.2**

P-42 WKY#8B-1	825.65 to 827.5	3892.7	413.4	4306.1	14.8	3.3	18.1
P-42 WKY#8B-2	827.5 to 829.4	5164.5	1440.5	6605.0	17.1	6.0	23.1
P-42 WKY #8T	**825.65 to 829.4**	**9057.2**	**1853.9**	**10911.1**	**31.9**	**9.3**	**41.2**
P-42 WKYColchesterRR	924.8 to 926	2000.3	518.3	2518.6	9.2	3.9	13.1
P-42 WKYColchester	927 to 928	3120.7	1861.2	4981.9	17.9	11.7	29.6
P-42 WKY#6DavisRR	1006.8 to 1007.11	424.7	269.2	693.9	55.3	46.6	101.9
P-42 WKY#6Davis	1007.11 to 1009.8	5644.4	2918.6	8563.0	28.0	15.7	43.6
	*Corrected for	Headspace	Volume				

Table 15 - Raw (as-received) gas contents for western Kentucky coal beds.

Core Run / Sample	**Depth of sample (ft)**	**Cum. Gas desorbed (ml) whole core***	**Cum. Gas desorbed (ml) crushed to -1mm***	**Total Gas desorbed (ml)**	**DAF total gas whole core Scf/ton**	**DAF total gas crushed Scf/ton**	**DAF total gas total Scf/ton**
P-42 WKY#11RR	665.5 to 673.77	3652.6	1818.3	5470.9	16.1	9.1	25.3
P-42 WKY#11A	673.77 to 675.65	6406.5	4119.7	10526.2	31.2	21.0	52.2
P-42 WKY#11B	675.65 to 677.55	8073.2	3130.0	11203.2	39.1	16.7	55.8
P-42 WKY#11C	677.55 to 678.88	3643.9	2820.4	6464.3	23.2	18.6	41.8
P-42 WKY#11D	678.88 to 680.18	942.7	1468.9	2411.6	19.2	26.0	45.2
P-42 WKY#11T	**673.77 to 680.18**	**19066.3**	**11539.0**	**30605.3**	**112.6**	**82.3**	**195.0**
P-42 WKY#9RR	782.1 to 784	6879.4	754.4	7633.8	31.8	5.7	37.4
P-42 WKY#9A	784.2 to 786.1	7954.7	3602.8	11557.5	34.7	18.7	53.4
P-42 WKY#9B	786.1 to 788.04	7654.8	3198.6	10853.4	35.3	16.2	51.5
P-42 WKY#9C	788.04 to 789.35	4558.7	2395.2	6953.9	28.8	16.6	45.4
P-42 WKY#9T	**784.2 to 789.35**	**20168.2**	**9196.6**	**29364.8**	**98.8**	**51.4**	**150.2**
P-42 WKY#8B-1	825.65 to 827.5	3892.7	413.4	4306.1	18.5	4.1	22.6
P-42 WKY#8B-2	827.5 to 829.4	5164.5	1440.5	6605.0	21.4	7.5	28.9
P-42 WKY #8T	**825.65 to 829.4**	**9057.2**	**1853.9**	**10911.1**	**39.9**	**11.6**	**51.5**
P-42 WKY	924.8 to 926	2000.3	518.3	2518.6	11.5	4.9	16.4

ColchesterRR							
P-42 WKYColchester	927 to 928	3120.7	1861.2	4981.9	22.3	14.7	37.0
P-42 WKY#6DavisRR	1006.8 to 1007.11	424.7	269.2	693.9	55.3	46.6	101.9
P-42 WKY#6Davis	1007.11 to 1009.8	5644.4	2918.6	8563.0	35.0	45.6	80.6
	*Corrected for headspace volume						

Table 16 - Dry-ash-free (DAF) gas contents for western Kentucky coal beds

WKY boreholes, summer 2005, Hydrogen isotopic data for C1-C4 hydrocarbons and H2S
Gas compositional data calculated based on hydrogen-containing gas species

sample	**WKY 4**	**WKY 5**	**WKY 6**	**WKY 7**	**WKY 8**	**WKY 9**	**WKY 10**	**WKY 11**	**WKY 13**
# of analyses	2	3	3	2	1	1	1	1	1
composition	%	%	%	%	%	%	%	%	%
Methane	98.94	99.17	98.31	98.85	98.68	99.23	99.24	99.42	99.46
Ethane	0.62	0.48	0.74	0.67	0.81	0.51	0.40	0.33	0.31
H2S	0.31	0.24	0.75	0.35	0.22	0.13	0.27	0.18	0.16
Propane	0.12	0.10	0.18	0.12	0.26	0.12	0.08	0.06	0.07
iso-Butane	0.003	0.004	0.005	0.004	0.014	0.001	0.002	0.001	0.002
n-Butane	0.007	0.007	0.015	0.009	0.025	0.009	0.006	0.004	0.005
Butanes together	0.010	0.011	0.021	0.013	0.040	0.011	0.008	0.005	0.007
δD	**‰**	**‰**	**‰**	**‰**	**‰**	**‰**	**‰**	**‰**	**‰**
Methane	-217.4	-219.0	-222.9	-226.2	-204.8	-216.5	-215.3	-219.3	-224.7
Ethane	-191.4	-208.5	-221.5	-222.7	-226.8	-227.1	-226.9	-216.1	-229.5
H2S	-203.6	-185.1	-190.3	-188.8	-171.4	-181.7	-197.8	-186.7	-187.5
Propane	-101.0	-113.0	-124.3	-122.6	-130.0	-125.6	-109.2	-102.6	-121.1
iso-Butane	-31.9	-49.0	-43.7	-26.8	-22.4	-59.6	-51.6	-66.0	-34.5

n-Butane	-72.1	-50.4	-71.5	-49.6	-123.9	-70.5	-64.4	-43.9	-63.6

*CO_2 and N not included

Table 17 – Gas composition and isotope analysis data for western Kentucky coal beds.

Core hole	Big Run1	DC-04-9	DC-04-9	DC-04-9	DC-04-9	DC-04-9	DC-04-9	DC-04-9	DC-04-9
Sample		WKY #13A	WKY #13B	WKY #13C	WKY #10	WKY #9RR	WKY #9A	WKY #9B	WKY #9C
Parameter									
Major-Minor Elements in Coal Ash									
Aluminum Oxide (Al2O3)	18.46	6.14	22.22	N/A	18.07	19.37	20.30	10.94	11.97
Barium Oxide (BaO)	0.03	0.03	0.03	N/A	1.36	0.04	0.15	0.01	0.03
Calcium Oxide (CaO)	3.59	16.02	2.39	N/A	1.73	3.21	2.36	4.12	3.78
Ferric Oxide (Fe2O3)	25.68	44.30	24.96	N/A	26.48	13.5	16.10	48.53	42.32
Magnesium Oxide (MgO)	0.71	0.39	0.64	N/A	0.73	1.68	0.88	0.51	0.75
Phosphorus Pentoxide (P2O5)	0.09	0.07	0.23	N/A	0.10	0.32	0.06	0.04	0.09
Potassium Oxide (K2O)	2.07	0.52	1.72	N/A	2.63	3.7	2.48	1.22	1.58
Silicon Dioxide (SiO2)	42.04	12.06	43.81	N/A	37.92	50.74	52.97	23.61	31.87
Sodium Oxide (Na2O)	0.39	0.09	0.45	N/A	0.43	0.85	0.62	0.3	0.27
Strontium Oxide (SrO)	< MDL	0.02	0.04	N/A	0.06	< MDL	0.04	< MDL	< MDL
Sulfur Trioxide (SO3)	5.07	15.42	2.12	4.55	2.72	4.13	2.32	4.95	4.47
Manganese by X-Ray Flouresence	N/A	N/A	N/A	N/A	476	N/A	N/A	N/A	N/A
Titanium Dioxide (TiO2)	1.07	0.27	1.02	N/A	0.96	0.81	1.13	0.61	0.75
TOTAL	99.3	95.35	99.65	N/A	93.19	98.35	99.41	98.84	97.88
Proximate Analysis									
% Ash, dry	8.26	25.55	7.79	10.9	13.83	76.44	10.25	12.46	15.56
% Fixed Carbon, dry	52.26	38.49	53.49	52.1	45.97	6.45	50.73	48.7	45.74
% Moisture	11.31	1.80	2.24	1.98	1.76	2.38	1.73	2.63	2.53
% Volatile Matter, dry	39.48	35.96	38.72	36.98	40.20	17.07	39.02	38.84	38.7
Calorific Value, (BTU), dry	13350	11073	13905	13329	13007	2847	13648	12696	12442
Total Sulfur	2.95	4.98	2.00	3.27	4.00	6.00	2.25	6.16	6.37

Table 17 – Coal quality data for sampled coals and shales in western Kentucky from borehole DC-04-09.

Core hole	DC-04-10	DC-04-10	DC-04-10	DC-04-10	DC-04-10	DC-04-10
Sample	WKY#13	WKY#10	WKY#9RR	WKY#9A	WKY#9B	WKY#9C
Parameter						
Major-Minor Elements in Coal Ash						
Aluminum Oxide (Al2O3)	20.03	19.26	18.36	13.28	6.55	7.82
Barium Oxide (BaO)	0.07	0.06	0.04	0.03	0.02	0.02
Calcium Oxide (CaO)	2.88	1.62	3.68	1.41	15.97	2.24
Ferric Oxide (Fe2O3)	13.73	31.26	7.58	43.28	36.90	53.03
Magnesium Oxide (MgO)	1.44	0.89	1.97	0.38	2.89	0.41
Phosphorus Pentoxide (P2O5)	0.53	0.20	0.85	0.06	0.04	0.05
Potassium Oxide (K2O)	2.81	2.68	3.84	1.11	0.68	1.21
Silicon Dioxide (SiO2)	48.79	38.73	52.51	36.12	13.81	22.62
Sodium Oxide (Na2O)	0.65	0.40	0.91	0.32	0.16	0.17
Strontium Oxide (SrO)	0.04	0.04	0.02	0.02	0.02	0.01
Sulfur Trioxide (SO3)	2.96	1.73	3.28	1.39	18.21	2.62
Manganese by X-Ray Flouresence	5388	N/A	541	N/A	N/A	330
Titanium Dioxide (TiO2)	0.95	0.98	0.79	0.71	0.30	0.47
TOTAL	94.88	97.87	93.83	98.12	95.54	90.67
Proximate Analysis						
% Ash, dry	72.56	13.57	73.36	10.54	15.53	22.69
% Fixed Carbon, dry	6.2	45.69	11.06	51.79	44.86	43.61
% Moisture	1.59	1.40	1.48	1.63	1.66	1.21
% Volatile Matter, dry	21.24	40.74	15.58	37.67	38.61	33.7
Calorific Value, (BTU), dry	2526	13054	2855	13603	12597	11576
Total Sulfur	1.32	3.18	2.50	3.51	4.12	7.82

Table 18 – Coal quality data for sampled coals and shales in western Kentucky from borehole DC-04-10.

Core Hole	P-42	P-42	P-42	P-42	P-42	P-42	P-42	P-42	P-42	P-42	P-42	P-42	P-42	P-42	P-42
Sample	WKY #8 RR	WKY #8	WKY #11 RR	WKY # 11A	WKY # 11B	WKY # 11C	WKY # 11D	WKY # 9 RR	WKY # 9A	WKY # 9B	WKY # 9C	WKY # 8B-1	WKY # 8B-2	WKY # 6 RR	WKY # 6
Parameter															
Major-Minor Elements in Coal Ash															
Aluminum Oxide (Al2O3)	20.50	16.32	N/A	16.61	22.08	26.06	17.94	18.41	20.50	8.32	13.02	15.62	18.06	18.81	17.32
Barium Oxide (BaO)	0.05	0.04	N/A	0.03	0.04	0.06	0.1	0.06	0.05	0.46	0.03	0.03	0.05	0.04	0.03
Calcium Oxide (CaO)	0.59	2.32	N/A	2.86	2.01	0.84	1.53	4.74	1.53	5.56	5.36	8.92	1.33	3.01	1.06
Ferric Oxide (Fe2O3)	12.11	30.44	N/A	43.07	27.015	15.01	31.73	10.09	15.25	54.98	37.81	9.87	10.17	16.06	33.77
Magnesium Oxide (MgO)	1.63	1.61	N/A	0.39	0.84	0.56	0.97	1.95	0.86	0.27	0.67	2.22	2.28	1.77	0.85
Phosphorus Pentoxide (P2O5)	0.23	0.27	N/A	0.95	0.07	0.29	0.12	0.39	0.10	0.04	0.19	4.74	0.38	0.76	0.07
Potassium Oxide (K2O)	4.04	2.92	N/A	1.17	2.52	2.15	2.52	3.84	2.87	0.91	1.73	3.47	3.89	3.7	2.01
Silicon Dioxide (SiO2)	52.77	40.16	N/A	29.38	39.49	51.70	39.47	52.49	55.37	17.11	33.25	46.90	58.96	48.69	40.66
Sodium Oxide (Na2O)	0.83	0.63	N/A	0.34	0.61	0.56	0.55	0.81	0.68	0.23	0.32	0.70	0.99	0.81	0.51
Strontium Oxide (SrO)	0.02	0.02	N/A	0.02	0.04	0.03	< MDL	0.02	0.03	0.02	0.02	0.03	0.02	< MDL	0.02
Sulfur Trioxide (SO3)	1.29	2.66	2.77	1.82	2.1	0.87	1.89	6.19	1.31	3.74	3.52	5.09	2.51	3.67	1.12
Titanium Dioxide (TiO2)	0.86	0.85	N/A	0.85	1.18	1.30	1.02	0.79	1.08	0.44	0.67	0.60	0.84	0.8	0.81
TOTAL	94.92	98.26	N/A	97.50	98.14	99.44	97.84	99.78	99.44	92.08	96.59	98.21	99.48	98.12	98.24
Proximate Analysis															
% Ash, d	82.99	15.93	69.57	10.40	5.86	14.02	13.62	70.84	11.06	15.67	14.29	78.49	68.17	78.68	13.19
% Fixed Carbon, d	5.01	45.13	12.79	49.36	54.25	48.45	47.67	9.91	51.15	47.74	48.71	4.35	14.29	5.02	46.60
% Moisture	2.95	3.50	2.55	3.61	5.33	5.12	5.5	2.85	4.63	5.11	3.53	3.35	3.28	2.94	2.99
% Volatile Matter, d	12.00	38.94	17.64	40.24	39.89	32.53	38.71	19.25	37.79	36.59	37.00	17.16	17.54	16.3	40.21
Calorific Value, (BTU), d	1571	12589	3801	13189	13985	12571	12660	3459	13253	12282	12340	2297	4170	2136	13028
Total Sulfur	3.5	3.28	1.96	5.31	2.95	3.08	4.37	2.89	2.83	8.88	3.61	2.73	2.43	7.19	4.34

Table 19 – Coal quality data for sampled coals and shales in western Kentucky from borehole P-42.

Presentations

Eble, C.F., **C**oal bed methane potential of western KY coal beds. Presented at the KY Oil and Gas Association in Louisville KY in June, 2003.

Eble, C.F., Coal Bed Methane Potential of the Western Kentucky Coal Field, presented at the Strategic Research Institute Coal Bed Methane and Coal Mine Methane meeting in Denver, Colorado in May, 2004.

Eble, C.F., Coal bed methane research in western Kentucky: an update. Presented at the Petroleum Technology Transfer Council meeting in Evansville, Indiana in November, 2004.

Eble, C.F., An update of coal bed methane research in western Kentucky. Presented at a technical staff briefing at the National Energy and Technology Laboratory in Morgantown, West Virginia in November, 2004.

Eble, C.F., Evaluating the western Kentucky Coal Field for economic coal bed methane: an update. Presented at the Strategic Research Institute Unconventional Gas Revolution meeting in Denver, Colorado in December, 2004.

Eble, C.F**.,** Coal bed methane potential of the Western Kentucky Coal Field. Presented at the annual meeting of the Kentucky Oil & Gas Association in Lexington, KY, June, 2005.

CONCLUSION

A geologic assessment of the Illinois Basin has resulted in the generation of individual coal thickness, cumulative coal thickness, and coal overburden maps. Critical analysis of these maps has allowed for the identification of the most promising areas that may yield economic coal bed methane. Based on these maps, nine core holes were drilled. Analyses of the collected samples are still on-going, hence this report is interim and not complete.

Desorption data indicate a wide variety of gas contents that range from less than 50 scf/ton to more than 300 scf/ton. Lost gas values typically are low, and residual gas contents are often high; both of these measurements reflect slow desorption rates. Black shale roof rock samples that were analyzed contained moderate gas contents, and could possibly contribute to the overall gas resource. Gas analysis shows a dominance of methane in most of the samples (typically > 60%), the origin of which is both biogenic and thermogenic gas.

The effects of well completion techniques on produced gas content will help us better understand what is needed to produce economic CBM in the Illinois Basin. Pressure transient test measurements to determine the permeability of coals from the Illinois core samples will be performed soon, and subsequently used to design a well stimulation program for a pilot production test well. Additional data from the forthcoming Indiana and Kentucky drilling programs will also provide us with a better understanding of the range of gas contents in the Illinois Basin.