Reassessment of CO_2 Sequestration Capacity and Enhanced Gas Recovery Potential of Middle and Upper Devonian Black Shales in the Appalachian Basin

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Executive Summary

Continuous, low-permeability shale units are expected to be effective regional seals for Carbon dioxide (CO_2) storage in deeper zones. Black, organic-rich gas shales hypothetically have additional advantages: CO_2 may be sequestered in an immobile, adsorbed state and the sorption of CO_2 may displace additional natural gas. Initial estimates of sequestration capacity made in Phase I were based on a constant gas storage volume per ton of shale from CO_2 adsorption data. The gas storage capacity of shale is related to its total organic carbon content, however. A new estimate is compiled using basin-wide TOC data and includes the effect of estimated storage and displacement efficiency. Estimated Sequestration capacity was estimated at various displacement efficiencies in the deeper (at least 1,000 ft deep) and thicker (at least 100 ft thick) black shales in the Appalachian Basin. The capacity is 2.2 billion tons at a 3 percent efficiency analogous to the estimated efficiencies in saline aquifers. As much as 29.68 billion tons may be sequestered by assuming storage efficiencies analogous to those in continuous coals (up to 40 percent).

While laboratory research based on adsorption data from organic-rich gas shales suggest CO_2 storage is possible and may provide a mechanism for enhanced gas recovery, these processes have not been demonstrated *in situ*. Nominations for a potential demonstration project were solicited. Advanced well log data, rotary sidewall cores, shale rock properties analyses, adsorption isotherms, and production data were used to construct geostatistical reservoir models of porosity, permeability, and other factors. These models were used as the basis to simulate CO_2 injection into a shale gas reservoir to investigate the feasibility of injection and to assist in the design of a pilot injection project. Two injection scenarios were simulated: huff-and-puff and continuous injection. For a huff-and-puff project, simulations indicated minimal CO_2 storage because much of the injected CO_2 flowed back to the well bore during the puff phase. In the full pattern continuous injection scenario, incremental recoveries of natural gas are suggested providing the framework for a proof-of-concept demonstration.

Acronyms Used in This Report

CO_2 – Carbon dioxide

ECS – elementary capture spectroscopy

KGS – Kentucky Geological Survey

MRCSP – Midwest Regional Carbon Sequestration Partnership

PE – photoelectric factor

TOC – total organic carbon

UNIT ABBREVIATIONS USED IN THIS REPORT

ft – foot

g/cm^3 – grams per cubic centimeter

Gt – billion tons

km – kilometer

km^2– square kilometers

md – millidarcy

MCF – thousand cubic ft

MMCF – million cubic ft

psi – pounds per square inch

Introduction

In Phase I of the Midwest Regional Carbon Sequestration Partnership research, a methodology was developed to assess the potential CO_2 sequestration capacity in the Devonian shales in a study area consisting of the central and northern Appalachian Basin (211 billion tons) and Michigan Basin (21 billion tons). These estimates used the CO_2 gas storage capacity of shale based on CO_2 adsorption isotherms and an estimate of the density and volume across the study area. The CO_2 gas storage capacity of shale can be estimated from its total organic carbon (TOC) content (Nuttall and others, 2006). In the absence of laboratory TOC determinations, Schmoker (1979, 1993) proposed a method to determine the TOC of shale from formation density logs. In Phase II of the research, these estimates are updated by accounting for the variation of TOC of shale across the study area (thus allowing the CO_2 storage capacity to vary) and introducing an efficiency factor for displacement and storage.

CO_2 sequestration in shale, however, is speculative. Injecting CO_2 into shale is expected to be analogous to projects demonstrating CO_2 injection into coal for enhance coalbed methane recovery (Reznik and others, 1984; Gunter and others, 1997; Bachu and Gunter, 1998; Byrer and Guthrie, 1999; Reeves, 2002; Reeves, 2003). Nuttall and others (2006) demonstrated CO_2 is preferentially adsorbed in shale with respect to methane. Busch and others (2008) investigated the sequestration capacity of shale and found CO_2 adsorption to be a mechanism that tended to enhance the seal integrity of organic-rich shale for storage in deeper reservoirs. Successful injection of CO_2 into shale remains to be demonstrated considering its extremely low permeability (fractions of a nanodarcy in many cases). Supporting well data, the construction of a reservoir model, and a numerical simulation of CO_2 injection into shale are presented.

Study Area

The reassessment of shale sequestration capacity encompasses the northern and central portions of the Appalachian Basin within the area of the Midwestern MRCSP member states (Figure 1). The Middle and Upper Devonian marine shale sequence consists primarily of alternating black (organic-rich) and gray (more clastic- and clay-rich) shales deposited as distal facies of the Acadian clastic wedge that thin and pinch out generally southwestward across a basin centered in West Virginia and southwest Pennsylvania (Boswell, 1996). Figure 2 shows the correlation and stratigraphic nomenclature of the Middle and Upper Devonian shales in the study area.

Natural gas production from the shale has long been known especially from the Lower Huron Member of the Ohio Shale in southwest West Virginia and eastern Kentucky (Hamilton-Smith, 1993). The use of horizontal well and fracture stimulation methods developed in the pursuit of natural gas from the Mississippian Barnett Shale in the Fort Worth Basin has influenced the discovery and development of the Middle Devonian Marcellus shale, the lowermost black shale in the sequence, and renewed interest in the Upper Devonian Ohio Shale.

Method of Sequestration Capacity Estimation

Carr and others (2008) propose a method for estimating the CO_2 storage capacity of coal. Assuming sequestration in coal to be an analog for sequestration in continuous, low permeability, organic-rich, fractured shale gas reservoirs, then:

$$G_{CO2} = A * h_g * C * \rho_s * E$$

Where

G_{CO2}	Mass estimate of CO_2 storage
A	Geographic area of the basin or region for CO_2 storage calculation
h_g	Gross thickness
C	Concentration of CO_2 volume per coal volume
ρ_s	Standard density of CO_2
E	Storage efficiency factor

Area and gross thickness (volume)

As in the Phase I sequestration capacity estimate, to ensure sufficient burial and secondary reservoirs seals, only that portion of the basin where the shale interval is at least 100 ft thick at a depth of 1,000 feet or more was considered viable for sequestration. Figure 1 is a basin-wide isopach of the shale sequence modified from the map developed in Phase I was with new information from Pennsylvania.

Estimating the storage capacity of CO_2 in shale requires estimating the mass of a unit volume of shale. An analysis of bulk density of shale as measured in a standard nuclear log suite (RhoB) for the Middle and Upper Devonian shale interval was performed using 442 digital well logs (Figure 3). The distinct bimodal character of this distribution is a consequence of the lower average density of the higher TOC black shale zones compared to the higher density, less organic-rich, gray shale zones. Based on these data, an average shale density of 2.6 g/cm^3 was used for calculating tons of shale in place. The cell size for the gridded isopach data is 1 km by 1 km yielding a factor of 875,575.57 tons/km^{2}ft.[1]

Gross concentration and standard density of CO_2

For evaluating sequestration capacity of organic-rich shales, it is expected the primary storage mechanism will be in a Langmuir, near liquid, state adsorbed onto organic matter (Nuttall and others, 2006). It is therefore assumed for this estimate that the CO_2 storage capacity (standard cubic feet of CO_2 per ton of shale, Scf_{CO2}/ton) is given by CO_2 adsorption isotherms at a selected reservoir pressure. CO_2 adsorption isotherm data are not widely available for shale and the storage capacity per ton in this report is estimated from TOC data using the relation developed by Nuttall and others (2006) for a 400 psi reservoir pressure:

$$\frac{Scf_{CO2}}{Ton_{shale}} = 7.9 \cdot TOC + 20.7$$

TOC data were compiled from Ohio Division of Geological Survey (2007)and Repetski (2008). These data were supplemented with data from cores and outcrop samples collected by the Kentucky Geological Survey (KGS) at the request of Robert Milici of the U.S. Geological Survey and Rock Eval and TOC data acquired by the KGS. Many of the locations in this TOC data set consisted of multiple observations (several samples per well or outcrop). In these cases, the median of the data was determined and used in calculations. The distribution of these TOC data is shown in Figure 4. The range, 0.11–15.6 percent, and mean, 2.77 percent, are in the range of data reported by Zielinski and McIver (1982), Hamilton-Smith (1993), and other investigators. Figure 5 shows the TOC data control points and gridded data. It is of note that based on the gridded data, the basin center appears to have a lower TOC than do the basin margins. It is likely this phenomenon is at least partially a dilution effect; thicker shale intervals contain proportionally less organic-rich zones. Based on the conclusions of Schmoker (1979, 1993), the variation in TOC can be used as a proxy for the variation in shale density across the basin.

Storage efficiency factor

In Carr and others (2008) a range of 0.28 to 0.40 is proposed for coals. Boswell (1996) cites a recovery efficiency factor of only 0.17 in the gas shales of eastern Kentucky. Based on this observation, and to remain conservative a storage efficiency factor for the organic-rich shale is assumed to be 0.03, within the 0.01 to 0.04 range of efficiency factors cited for saline reservoir storage. While there is an

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[1] The mixing of International and U.S. units of measure is a computational convenience based on the linear scale units of maps employed and the available interval thickness data.

obvious justification for selecting an efficiency factor, there isn't a particularly compelling reason an efficiency factor as low as 0.03 should become enshrined. More research is needed in this area.

Compiling the estimate

ESRI ArcMap grid math operations were used to estimate the tons of shale in place for each cell based on the available parameters discussed.

CO_2 storage capacity of the shale

Figure 6 presents the result of the storage calculations. When the individual cells are summed over statewide areas, the total estimated sequestration capacity is 2.23 billion tons of CO_2. This new figure represents approximately 1 percent of the originally (MRCSP Phase I) estimated 211 billion tons of storage for the same area. For comparison, the storage capacity using the low and high ranges of efficiency are also provided.

Table 1. CO2 storage capacity in the Devonian black shales of the Appalachian Basin (billion tons).

State	CO_2 (Gt) E=3%	CO_2 (Gt) E=28%	CO_2 (Gt) E=40%
Kentucky	0.10	0.93	1.34
Ohio	0.51	4.78	6.82
Pennsylvania	0.80	7.46	10.66
West Virginia	0.82	7.61	10.87
Total	**2.23**	**20.78**	**29.68**

Towards demonstration of CO_2 sequestration and enhanced gas recovery in shale

The total storage capacity estimates exhibit such a wide range because so many factors are not well known. One of the main justifications for examining the potential for CO_2 sequestration in shale is the possibility that analogous to enhanced gas recovery in coals, CO_2 injection into shale may have the same benefit. With the goals of testing CO_2 injectivity into shale, enhanced shale gas recovery, and the efficiency of CO_2 sequestration, a demonstration project is needed. Essential to that effort, a feasibility study to model the shale reservoir and simulate CO_2 injection was initiated with MRCSP funding and an additional research allocation for sequestration research made by the Kentucky General Assembly (Incentives for Energy Development and Independence Act, 2007, "HB-1").

A solicitation was issued for nominations for a test injection well. The Pike County Judge Executive formed an industry group and nominated a gas well as a potential injector and two nearby wells as monitoring wells.

Burk Branch Project wells, Pike County, eastern Kentucky

Interstate #3 Panther Land (API 16195017180000) is located along Burk Branch in southwestern Pike County, Kentucky (Figure 7) and was nominated as the demonstration injection well. Originally drilled as a Pennsylvanian sand gas well in 1951, it was drilled deeper, logged, cased, and completed as a Devonian shale gas well in 1991. Some time prior to 1997 the well was shut-in due to its proximity to ongoing surface mining operations thus no production records are available. The casing was perforated at depths between 3,334 ft and 3,494 ft in the Lower Huron Member of the Ohio Shale. Additional data required for modeling and simulation (advanced well logs, porosity, permeability, and other parameters) can't be acquired from cased holes. The two nominated monitoring wells are shot wells with no expectation that such data could be acquired from them. Available well log data for the Interstate #3 Panther Land is summarized in Figure 8.

Rosewood Resources #02 Ted Bargo (API 16121014490000) was drilled in Knox County, eastern Kentucky (Figure 7) in 2006 to a total depth of 2,238 ft in the Silurian Lockport carbonates. A total of 110 ft of core from Cleveland Member of the Ohio Shale at 1,990 ft to the base of the Lower Huron Member of the Ohio shale at 2,110 ft. Core analyses, petrology, methane adsorption isotherms, Rock Eval, and shale rock properties data for this core were acquired and used to calibrate advanced well log data (Schlumberger Elemental Capture Spectroscopy, ECS, log). Figure 9 is a summary of the gamma ray density log through the Devonian shale interval showing the cored intervals. Measured porosity from core ranges from 0.6 to 4 percent with a mean of 1.6 percent. The available mineralogy, petrology, Rock Eval, and porosity data were used to calibrate the ECS log run in the well for shale modeling. These data were also used as a reference case to assist in the calibration and analysis of the logs acquired in the Blue Flame #K-2605 Batten and Baird well and to supplement the shale characterization data set used in building a shale reservoir model for simulation.[2]

[2] The Rosewood #02 Bargo well data set has been released for use in shale research and remain proprietary with respect to unrestricted public release.

Blue Flame #K-2605 Batten and Baird (API 16195058900000) was drilled in Pike County, eastern Kentucky approximately 5.6 miles from the Interstate #3 Panther Land. Without the option to acquire data for modeling and simulation from the nominated Interstate well and with the nearest adequate data set more than 70 miles distant, additional detailed shale reservoir characterization data were required. The Blue Flame #K-2605 Batten and Baird well was identified as a nearby (5.6 miles) opportunity to acquire detailed shale reservoir characterization data for modeling. A piggy-back project to acquire data was proposed to Battelle Memorial Institute and the Midwest Regional Carbon Sequestration Partnership (MRCSP). Funding from Battelle/MRCSP and HB-1 were secured along with an in-kind services discount from Schlumberger Carbon Services. A standard open-hole nuclear logging suite (Platform Express/Triple-combo), an elementary capture spectroscopy (ECS) log, and 19 rotary sidewall cores were acquired. Chesapeake Appalachia contributed tight rock, shale analytical laboratory and petrographic work for the sidewall cores and drill cuttings. These well logs and analytical data were processed by Schlumberger to produce a shale-specific analytic model to characterize lithology, mineralogy, gas content, total organic carbon, and others over the shale interval in the Blue Flame well.

To provide sufficient sample volume for all analyses and shale modeling, the 19 rotary sidewall core plugs were recovered in closely spaced pairs (Figure 10). A bulk density gamma ray cross plot (Figure 11) reveals a relationship between higher gamma ray, lower density shale units with higher TOC and the higher density, lower gamma ray gray shale units with less organic carbon. The Cleveland Shale Member of the Ohio, however, is distinctly off this trend. Bulk density photoelectric factor (PE) cross plots of each unit (Figure 12) indicate the Cleveland exhibits a somewhat lower PE possibly indicating a slight predominance of Montmorillonite or Smectite mixed-layer clays difficult to differentiate with standard X-ray analyses.

X-ray diffraction mineralogic analyses of bulk and clay fractions were performed on composited air rotary cuttings collected at 10 ft intervals. Laboratory analyses were performed by Chesapeake Appalachia. TOC and x-ray compositional data for the Blue Flame #K-2605 well are presented in Figure 13. Figure 14 is a summary of the X-ray and TOC data comparing the Rosewood #02 Bargo and Blue Flame #K-2605 Batten and Baird wells. Bulk and clay mineralogy differ between the wells, but are within the typical compositional range of the Devonian shale in the Appalachian Basin (Hosterman and Whitlow, 1983).

Organic matter occurs in the largely marine shale primarily as algae and unidentified bituminite (Figure 15) and Rock Eval and TOC analysis indicates a lean (Figure 16) source rock potential with a calculated bitumen reflectance (%R_o) between 0.94 and 1.77 within the oil to wet gas and condensate maturity window. TOC from sidewall plugs and drill cuttings (Figure 17) were used to calibrate the ECS log model to obtain continuous estimates of the adsorbed and free gas volumes in the shale (Figure 18).

Table 2 summarizes the porosity and permeability findings for the 10 pairs of rotary sidewall cores acquired in the well. Gas filled porosity averages 2% and permeability averages 0.0000728 millidarcys (md).

Table 2. Porosity and permeability analysis of rotary side wall core plug groups for the Blue Flame #K-2605 Batten and Baird well.

Sample Group	Unit	Code	Depth (ft)	Gas Filled Porosity (%)	Permeability (md)	Lithology	Notes
G1	(Mssp.) Sunbury	339SNBR	4,015.0	n/a	n/a	mudstone	Thin section
G2	Cleveland	341CLVD	4,181.9	2.02	0.000076	mudstone	
G3	Three Lick Bed	341TLBD	4,319.9	1.57	0.000056	mudstone	SEM
G4	Upper Huron	341HURNU	4,348.0	n/a	n/a	mudstone	Thin section
G5	Upper Huron	341HURNU	4,373.9	2.74	0.000106	mudstone	SEM
G6	Middle Huron	341HURNM	4,473.9	1.59	0.000063	mudstone	
G7	Middle Huron	341HURNM	4,612.9	2.02	0.000071	mudstone	SEM
G8	Lower Huron	341HURNL	4,672.0	n/a	n/a	mudstone	Thin section
G9	Lower Huron	341HURNL	4,696.9	2.08	0.000065	mudstone	
G10	Lower Huron	341HURNL	4,796.0	n/a	n/a	mudstone	Thin section
Average				**2.00**	**0.0000728**		

For building the reservoir model, the stratigraphic context of the three key study wells is shown in cross section in Figure 19. Production data sets from 7 wells (Figure 20, Appendix) were selected for geostatistical modeling and history matching. Monthly production data by well is publicly available only for Kentucky wells completed since 1997. Wells completed after 1997 were selected that produce from the shale interval only and have at least 60 months of publicly available production data. History matched gas production data served as proxys for characterizing the fracture permeability using geostatistical methods.

These data were provided to Advanced Resources International for simulating CO_2 injection into a shale reservoir using their COMET3 software. COMET3 is a multi-phase, dual-porosity, dualpermeability model used extensively in simulating enhanced gas recovery in coals. Schepers and others (2009)[3] report the modeling and simulation results. Figure 22 shows an optimized production history match for the Blue Flame #K-519 Wright well in Pike County. Table 3 shows the range of modeled parameters and the optimized values derived from history matching and modeling. The Langmuir volumes and pressures were optimized from data available in Nuttall and others (2006). Geostatistical models of porosity, matrix permeability, and fracture permeability (Figure 23) were constructed.

Table 3. Main model parameters and optimized values used for reservoir simulation using COMET3 (Schepers and others, 2009).

Parameters	Units	Minimum	Maximum	Optimized
initial water saturation	%	0	10	2
Permeability Upper Ohio	mD	5.00E-05	0.5	1.80E-03
Permeability Lower Huron	mD	5.00E-04	5	1.80E-02
Permeability horizontal Anisotropy		0.1	10	4.6
Porosity Upper Ohio	%	0.1	3	0.70
Porosity Lower Huron	%	0.1	5	1.50
VL CH4	scf/t	17.3	50.4	38.9
PL CH4	psia	280	1960	1252
VL CO2	scf/t	30	320	131
PL CO2	psia	180	2790	1754
Skin well 116231	-	0	-5	-2
Skin well 123437, 115010	-	0	-5	-4
Skin other wells	-	0	-5	-3

Two scenarios were investigated with the Lower Huron Member of the Shale as the injection zone. These scenarios assumed initiation of CO_2 injection at the end of the history match period. A full-field continuous injection case and a huff-and-puff cyclic injection case were modeled. In addition a permeability–height ("kh") sensitivity analysis was performed to investigate possible vertical variations in permeability distribution and the effect of thin layers. Table 4 presents the results of the reservoir simulation. The utilization ratio is defined as incremental CH_4 recovery divided by the volume of injected CO_2.

[3] It should be noted this is a reference to a pre-print of a paper given at the 2009 Annual Meeting of the Society of Petroleum Engineers, San Diego, California. After writing that paper, the authors discovered a scaling error that led to a prediction of early breakthrough in many of the modeled injection scenarios. That scale error is corrected in this discussion.

Table 4. Summary of huff-and-puff and full pattern continuous injection scenarios (Schepers and others, 2009).

		Huff-and-Puff Scenario		
	CO_2 Injected (tons)	CH_4 Recovery (MMcf)	Recovery Factor (%)	Utilization Ratio (Mcf/ton)*
Full Thickness	300	7.5	0.2	-
Half Thickness	300	5.8	0.4	-
Tenth Thickness	300	3.8	1.1	-
Tenth Thickness	1000	-	-	-
		Full Pattern Scenario		
	CO_2 Injected (tons)	CH_4 Recovery (MMcf)	Recovery Factor (%)	Utilization Ratio (Mcf/ton)*
Full Thickness	300	43.6	1.4	0.37
Half Thickness	300	33.8	2.2	0.67
Tenth Thickness	300	22.8	6.5	2.4
Tenth Thickness	1000	23.7	6.8	1.62

Results and discussion

A method to assess the CO2 sequestration capacity of black gas shales has been developed that takes into account the variability of the organic content of the interval. While displacement and storage efficiency data are not available, calculations suggest a storage capacity of 2.3 billion tons (3 percent efficiency analogous to efficiency estimates in deep brine storage) in the deeper and thicker portions of the Devonian shale in the Appalachian Basin. If efficiencies similar to coal are realized, as much as 29.68 billion tons of CO_2 may be sequestered.

Available data suggest CO_2 sequestration in organic-rich gas shales is feasible. Simulated full pattern injection scenarios suggest appreciable incremental recoveries of natural gas. Due to low permeability and thus injection rates, it isn't likely that these shales will be a primary sequestration target. However, their capacity to adsorb CO_2 is expected to increase the effectiveness of these shales as regional seals for deeper sequestration. Future economic factors (low price of CO_2 and high natural gas price) will determine whether enhanced natural gas recovery in shale using CO_2 injection will be attempted on commercial scales.

Modeling the shale and reservoir simulation indicates continuous injection of CO_2 provides the best results for enhanced gas production. The huff-and-puff case was not as efficient as the continuous injection case possibly due to the amount of free and sorbed CO_2 that flowed back during the production phase. The most efficient injection scenarios are realized by injecting CO_2 into selected, thinner, zones to maximize displacement efficiency and CO_2 retention. Injection of as little as 300 tons of CO_2 could be sufficient for a proof of concept demonstration.

Findings

- TOC varies across the Appalachian Basin with lower values toward the basin center possibly because of greater shale thicknesses contributing to a dilution effect.
- Depending on storage efficiency, as much as 29.68 billion tons of CO_2 may be sequestered in the areas of deeper and thicker shale.
- Simulation of huff-and-puff CO_2 injection shows little promise for CO_2 storage or enhanced gas recovery.
- Continuous full pattern injection of CO_2 suggests both sequestration and incremental recovery of gas are feasible.

Acknowledgments

I'd like to recognize the Kentucky General Assembly, especially Rep. Rocky Adkins, for recognizing the value of sequestration research and passing the Incentives for Energy Development and Independence Act ("HB-1"). Rosewood Resources, Dallas, Texas donated extensive analytical work and well logs on the shale core from their #02 Bargo well, Knox County, Kentucky. Pike County Judge Executive Wayne T. Rutherford nominated nominated the Burk Branch Project and the Interstate #3 Panther Land well site for demonstration of CO_2 injection. Jack Sykes, Phillip Elswick, Mike Spicer, and others from Summit Engineering, Pikeville, Kentucky have provided land work and site support. Ken Hall, General Manager of Blue Flame Energy Corp., Pikeville, Kentucky provided access to their #K-2605 Batten and Baird well for coring and logging. Dennis Rohrer, Interstate Natural Gas and CrossRock Drilling helped with logistics on the Blue Flame #K-2605 Batten and Baird well. David Ball, Neeraj Gupta, and Jacqueline Gerst of Battelle, Columbus, Ohio helped coordinate supplementary funding for logging and coring through their piggy back drilling program. Dwight Peters, Schlumberger Carbon Services and Ira Terry, Schlumberger Oilfield Services helped coordinate logging services and log processing. Ed Rothman and Clay Wilcox of Chesapeake Appalachia, Charleston, West Virginia made arrangements for cuttings and core analysis of material from the Blue Flame #K-2605 Batten and Baird well. George Koperna and Karine Schepers of Advanced Resources International, Houston, Texas conducted the reservoir simulation and modeling.

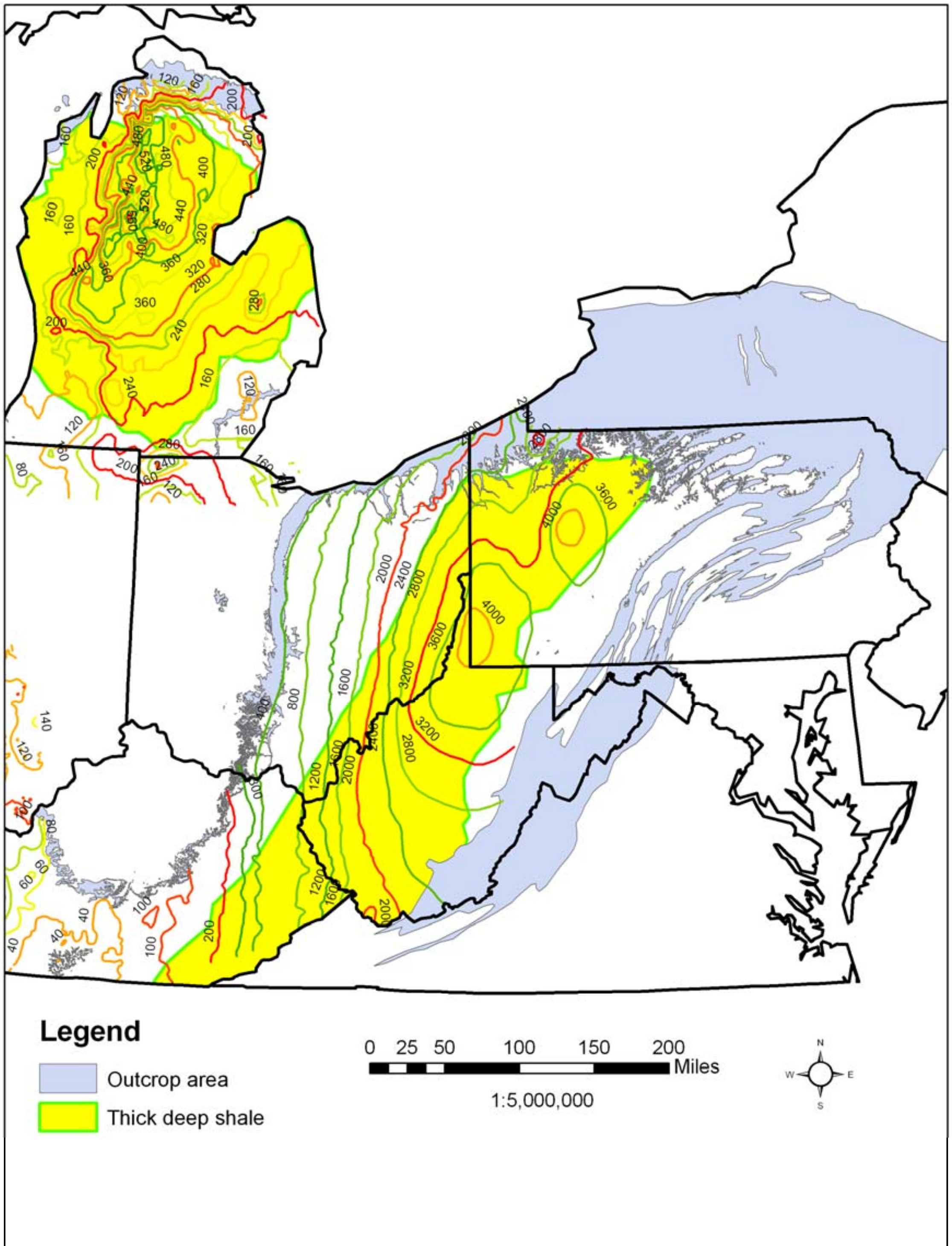


Figure 1. Central and northern Appalachian Basin Devonian shale assessment area showing shale thickness in feet and the area of thick (100 ft or more) and deep (1,000 ft or more) shale.

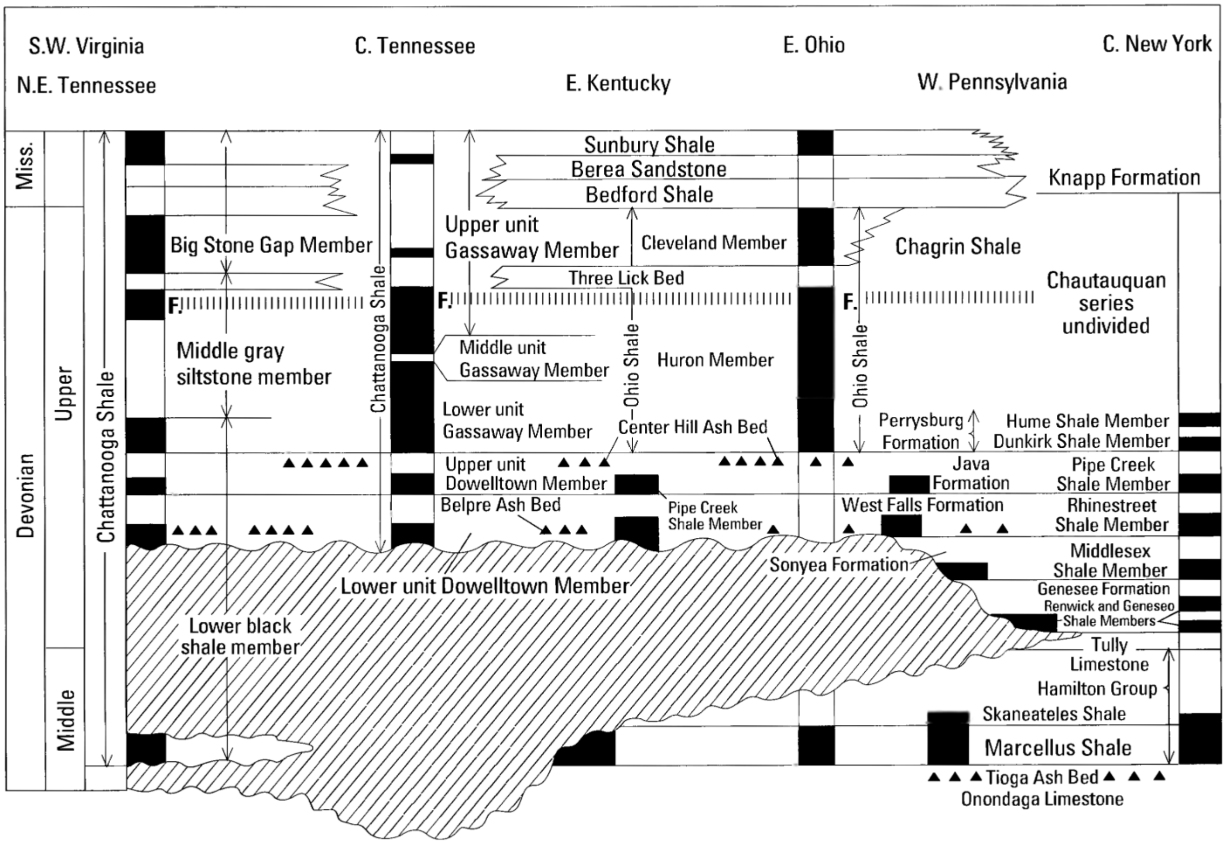


Figure 2. Stratigraphic nomenclature of the Middle and Upper Devonian shales in the central and northern Appalachian Basin with black shales indicated by shading (de Witt and others, 1993; Boswell, 1996).

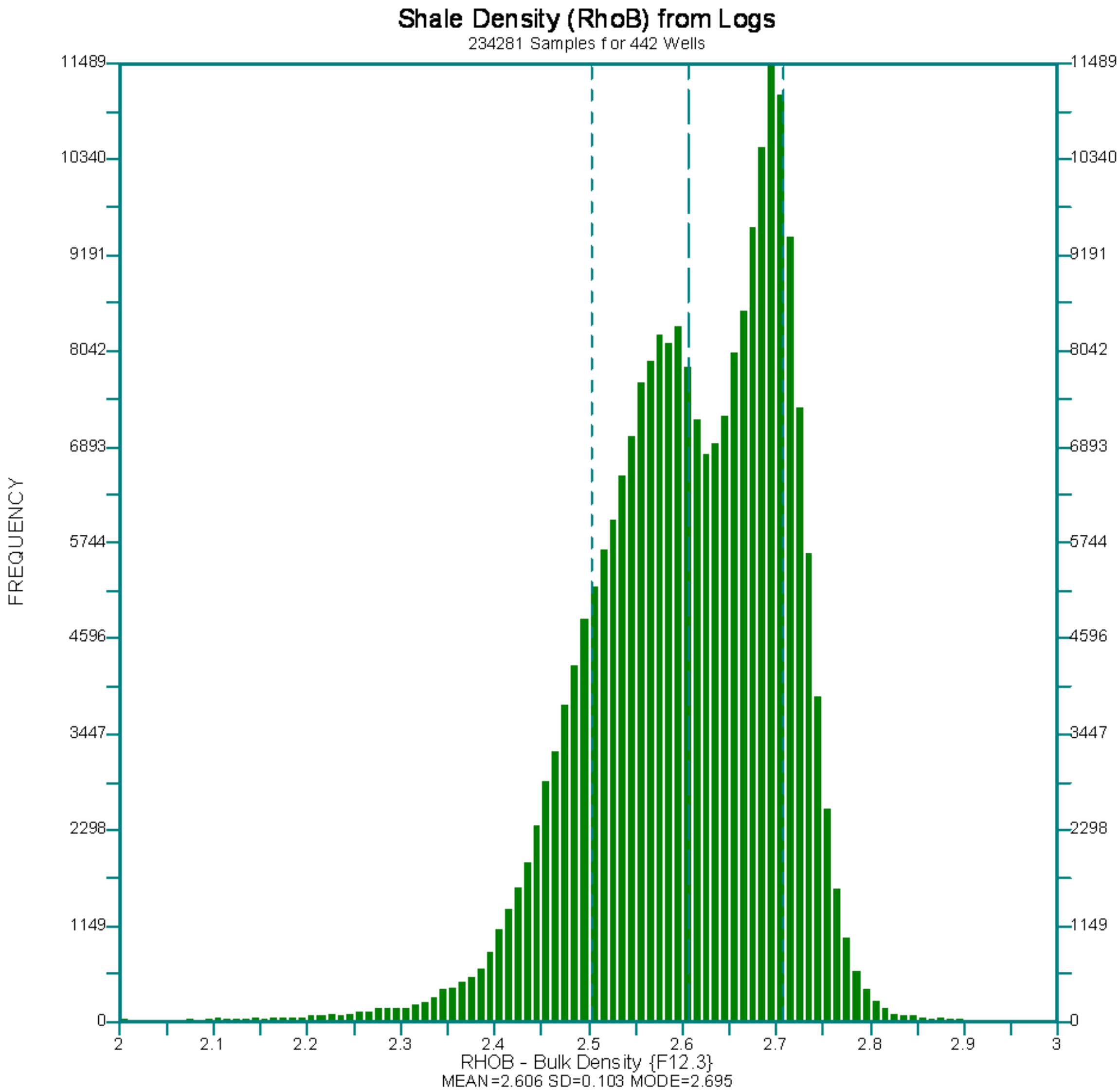


Figure 3. Bulk density of the black shale interval for 442 wells.

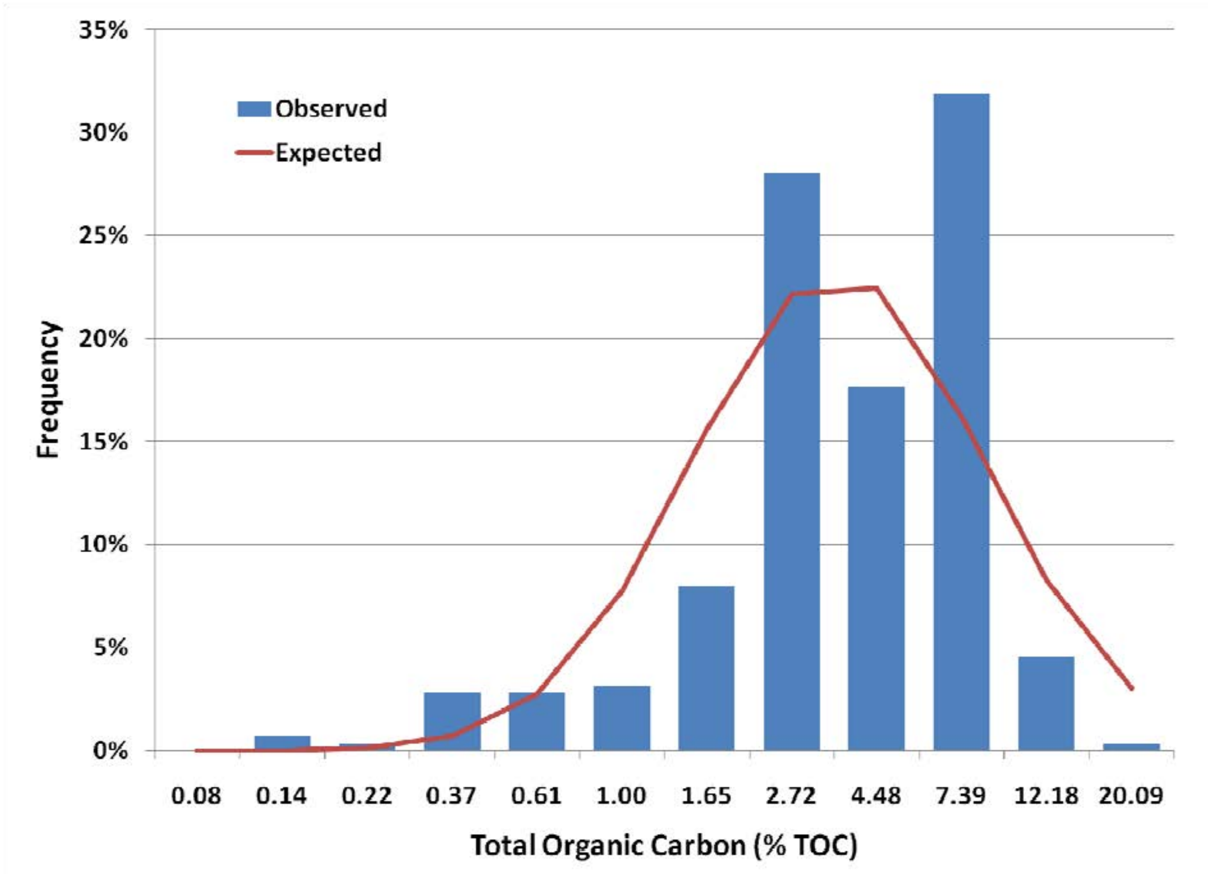


Figure 4. Total organic carbon (TOC percent) data distribution compared to an expected log normal distribution.

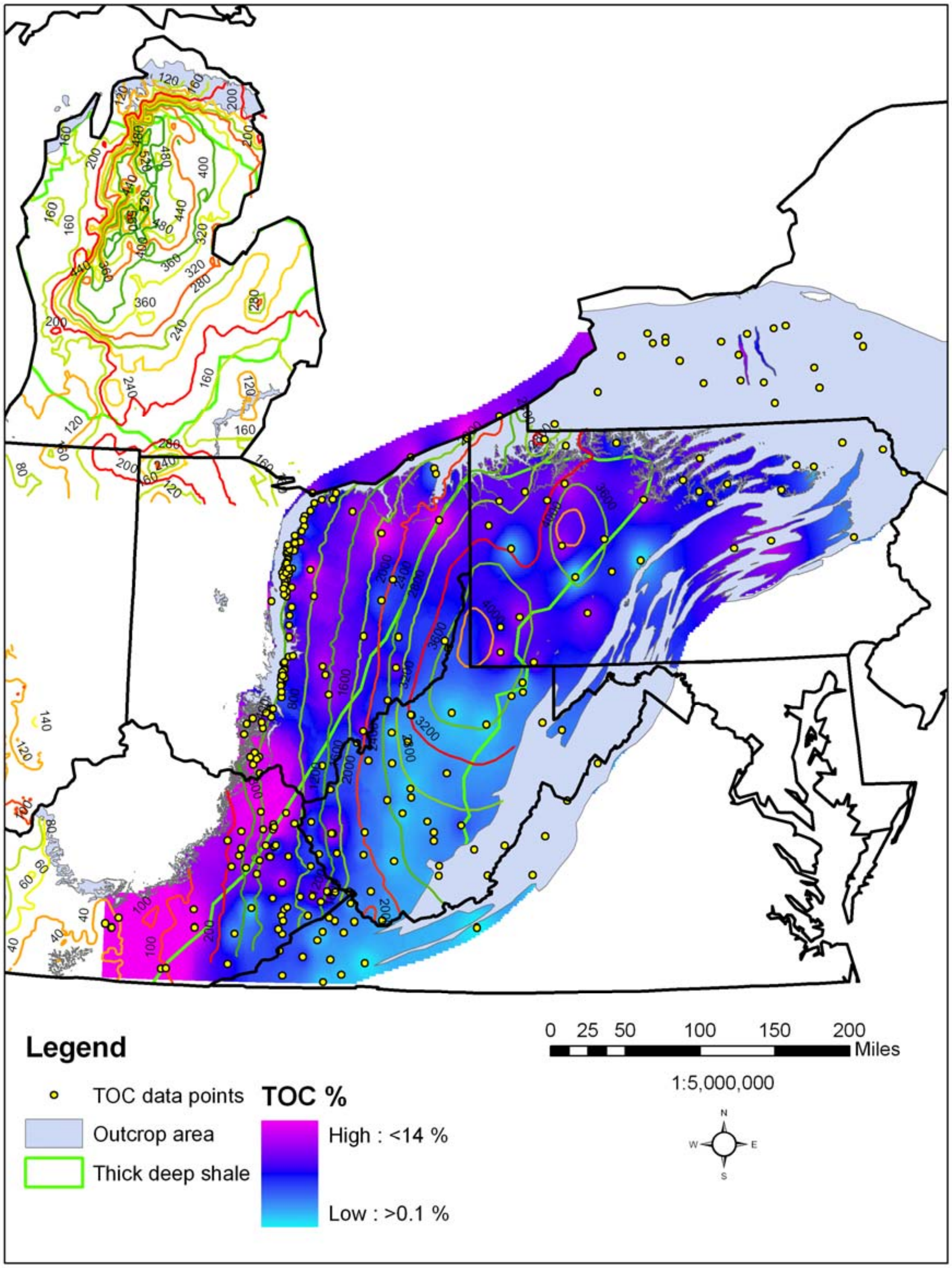


Figure 5. Spatial distribution of percent TOC data across study area including isopach of the total shale thickness.

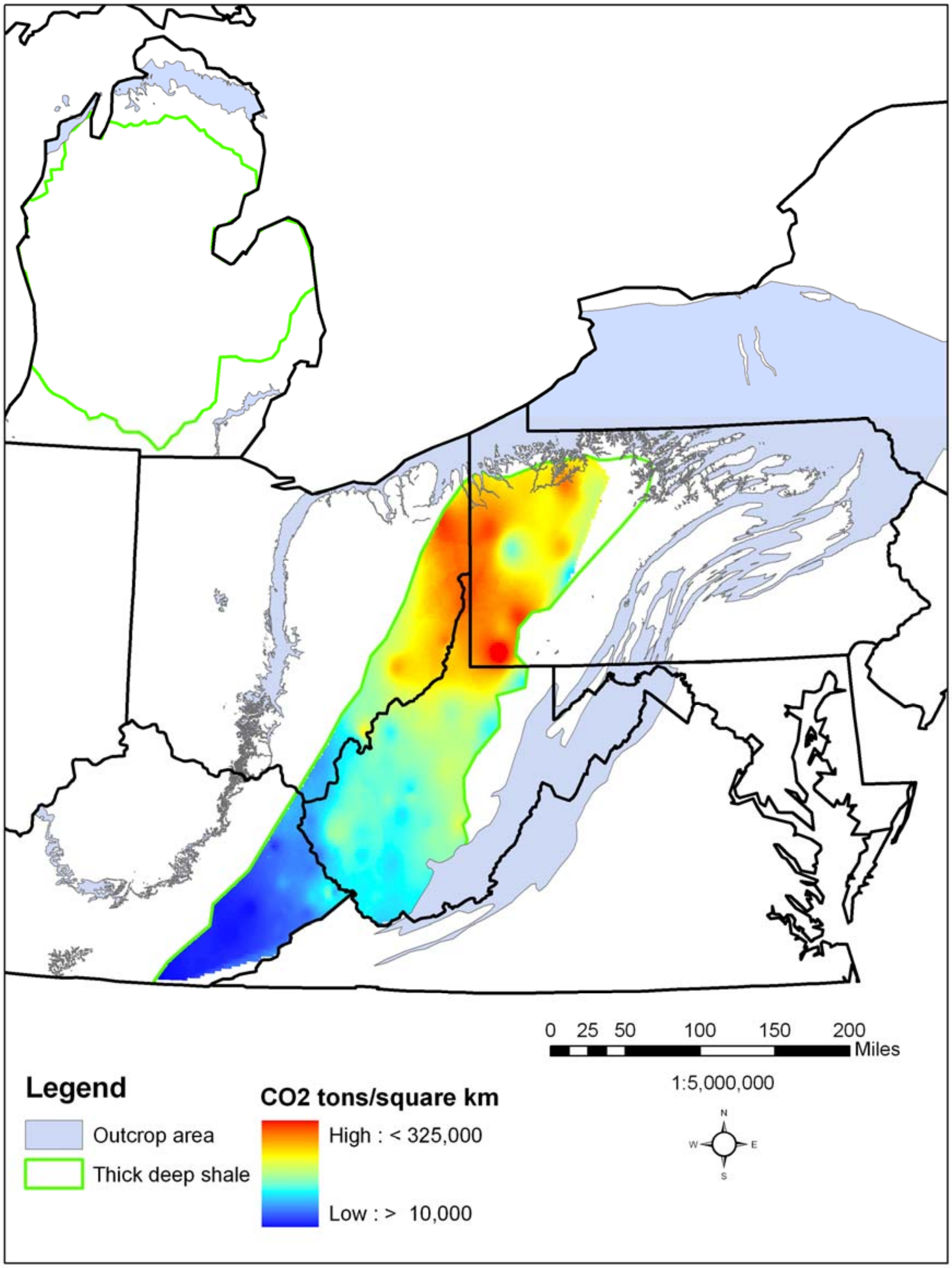


Figure 6. Estimated CO_2 tons per km^2 in area of thick and deep shale assuming a 3 percent storage efficiency factor.

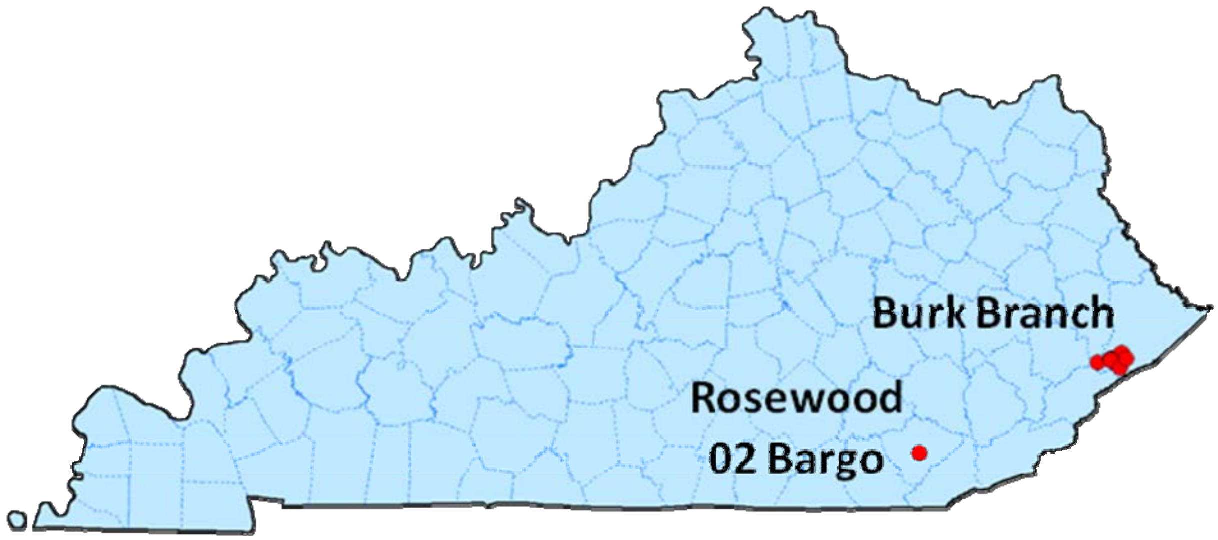


Figure 7. Burk Branch project area for pilot CO_2 injection into Devonian shale.

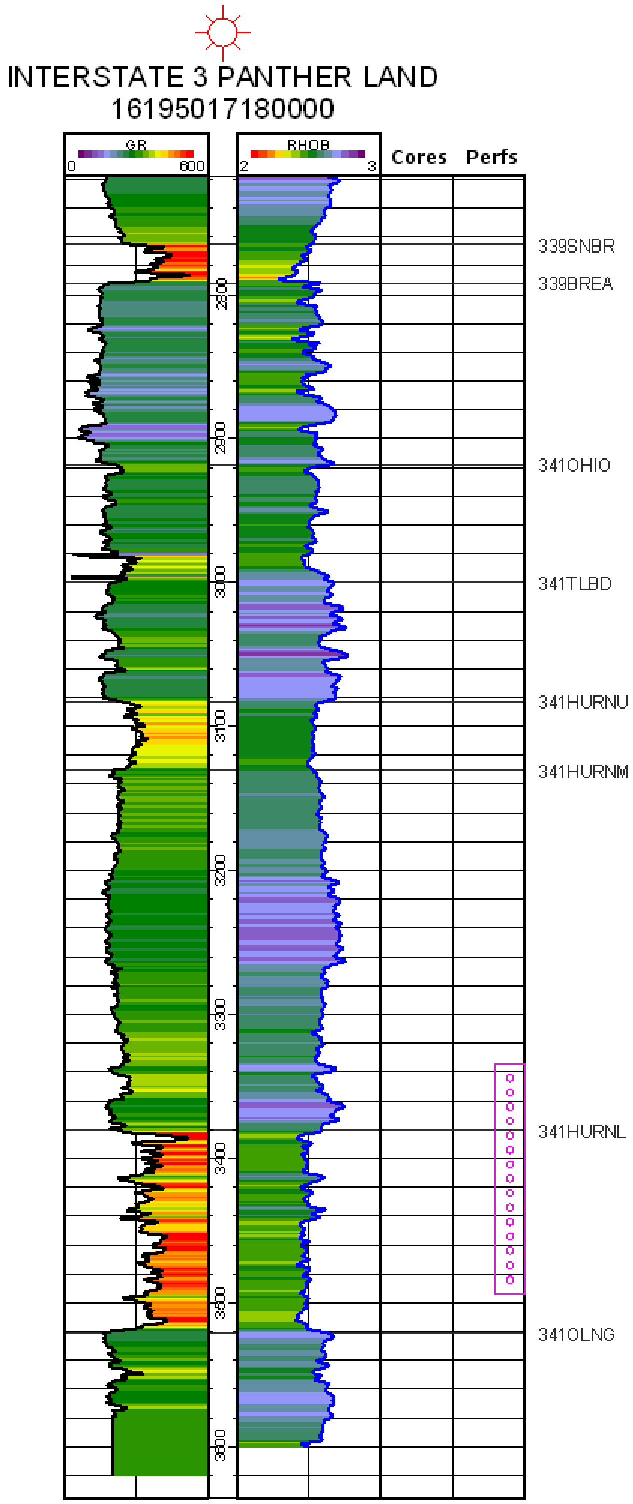


Figure 8. Gamma ray and density log of the Interstate #3 Panther Land, the nominated injection well in the Burk Branch Project.

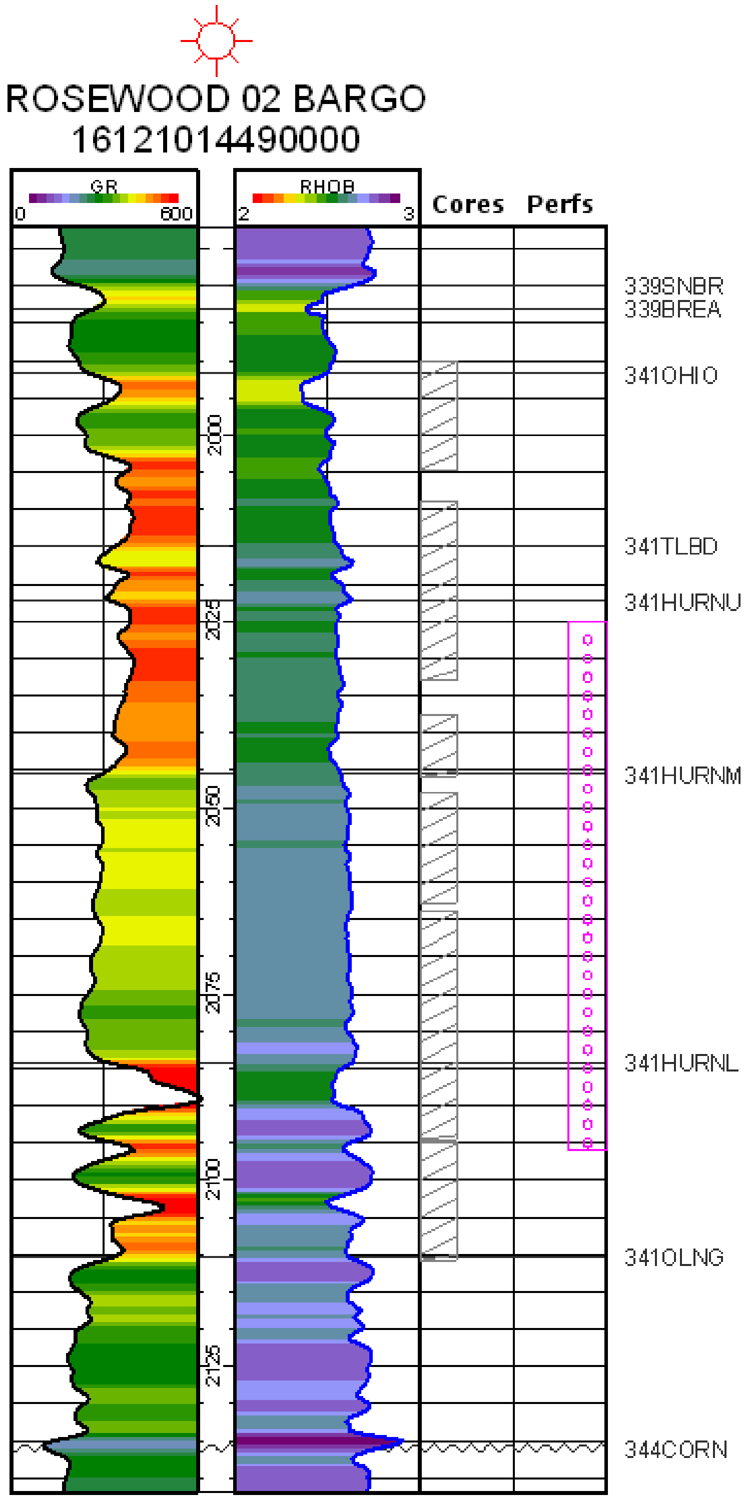


Figure 9. Gamma ray density log for the Rosewood #02 Bargo well, Knox County, Kentucky showing cores and completed interval.

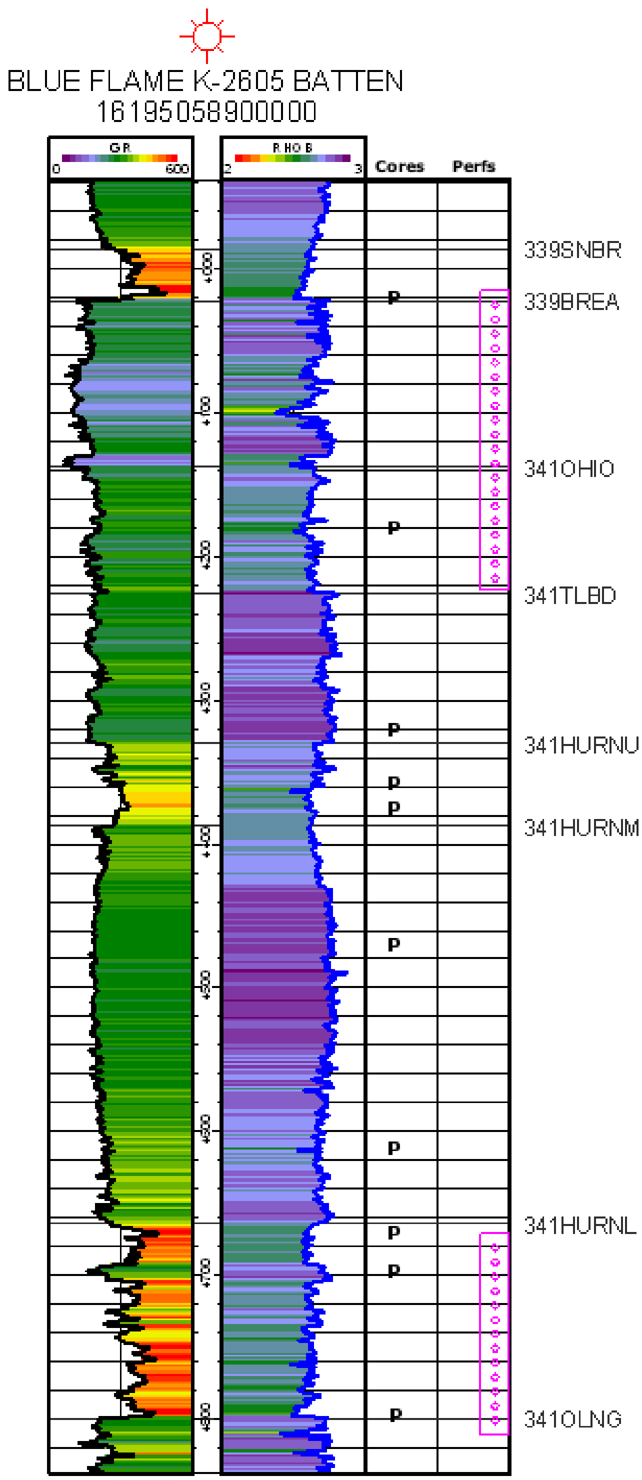


Figure 10. Gamma ray density log of the Blue Flame #K-2605 Batten and Baird well showing locations of rotary sidewall core plugs (P).

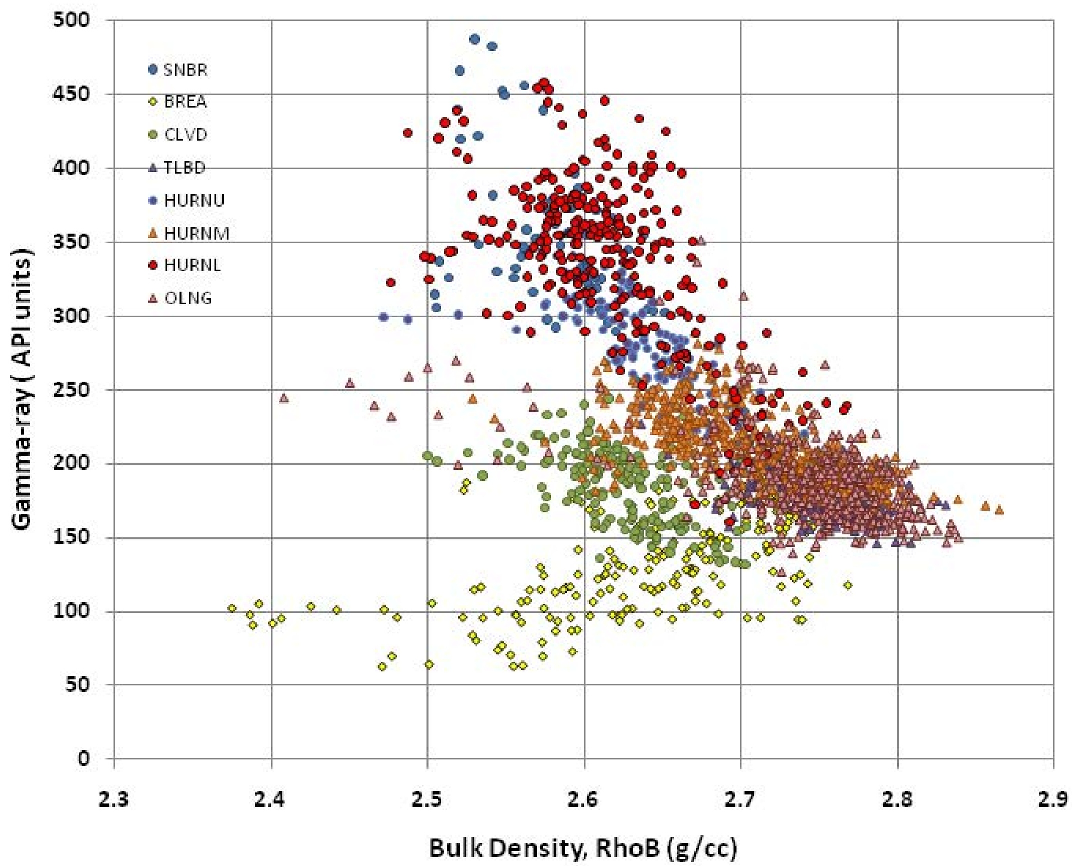


Figure 11. Bulk density versus gamma-ray crossplot for the Blue Flame K-2605 Batten and Baird well, Pike County, Kentucky .

Black, more organic-rich zones

Grayer, more quartz and clay-rich zones

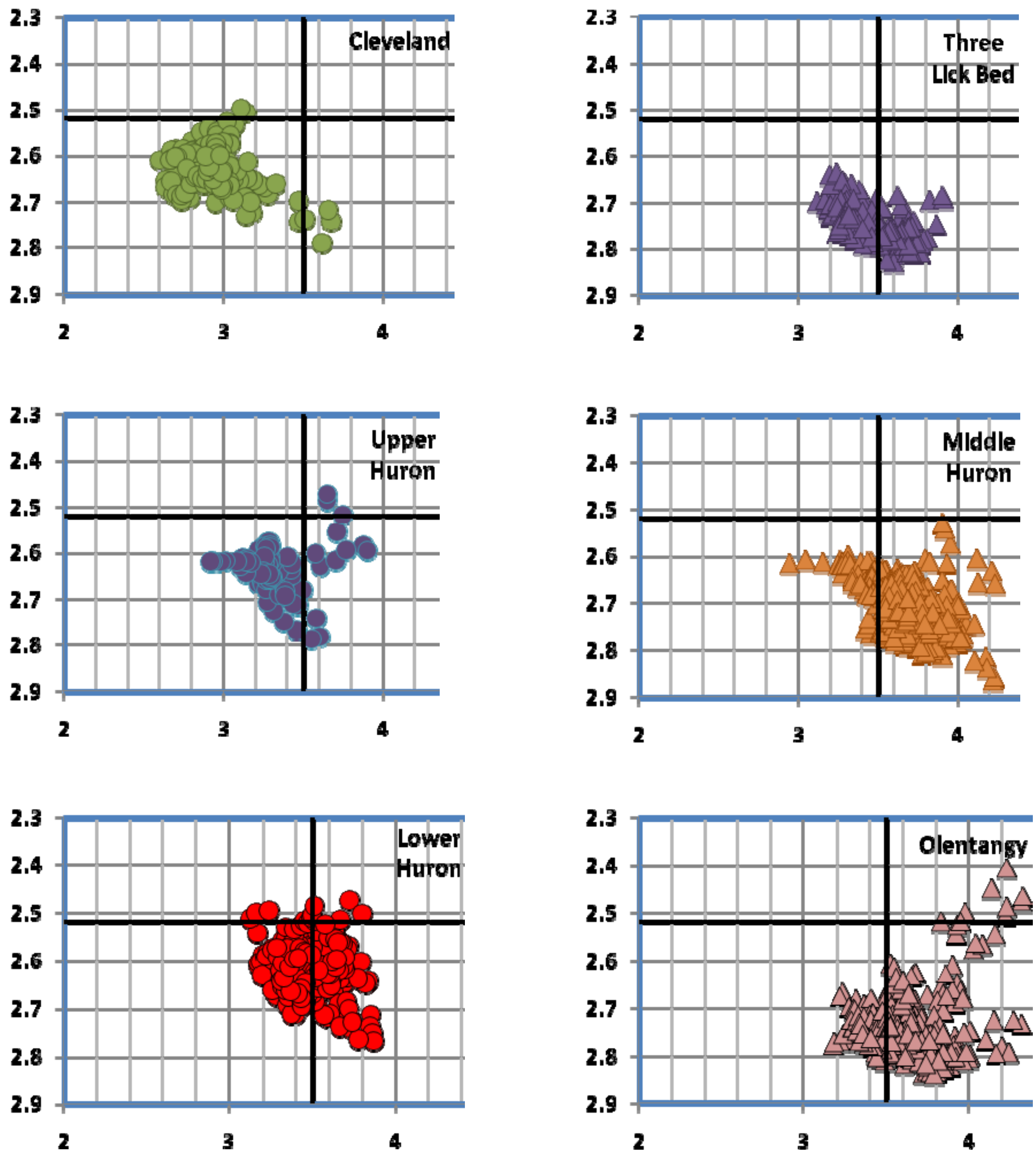


Figure 12.Lithology cross plot of photoelectric factor (Pe, x-axis) and bulk density (RhoB, y-axis) by shale unit with illite reference lines (Pe=3.5, RhoB=2.52). Refer to Schlumberger (2009).

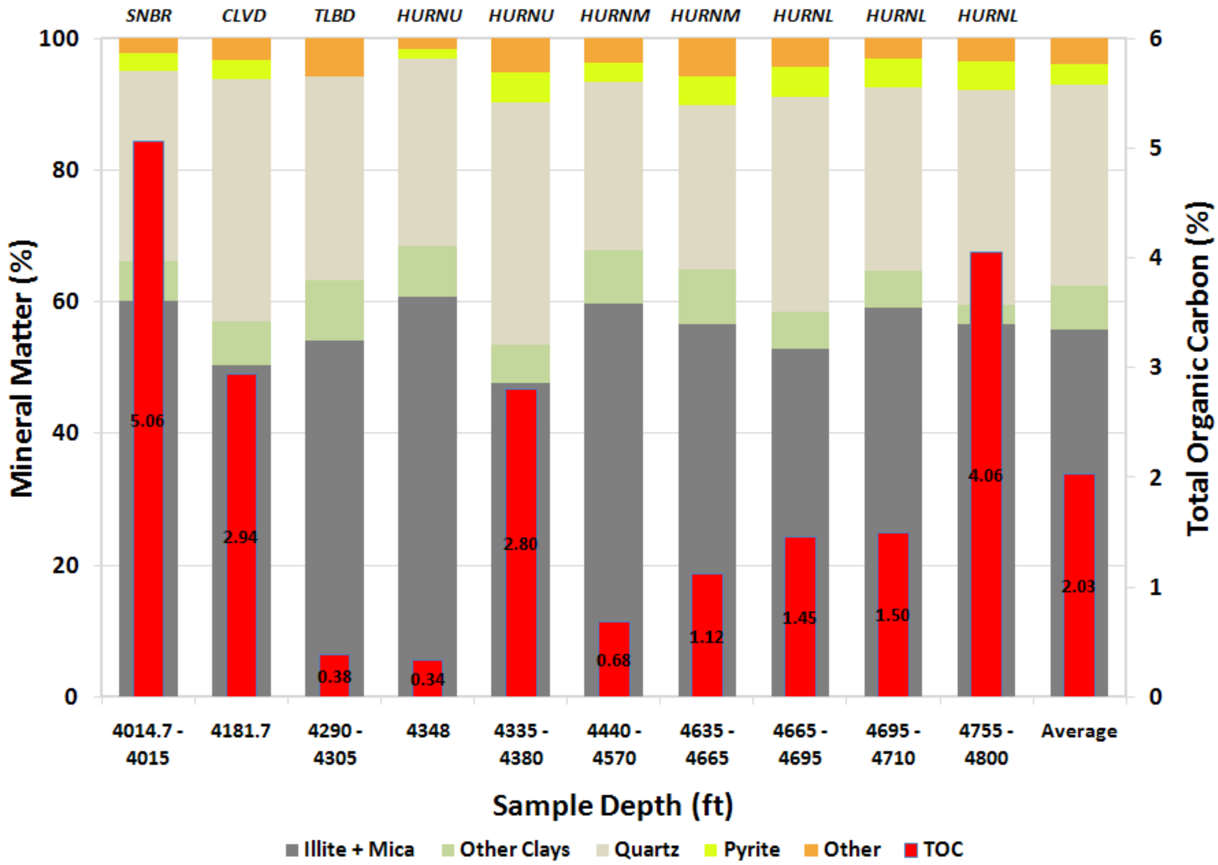
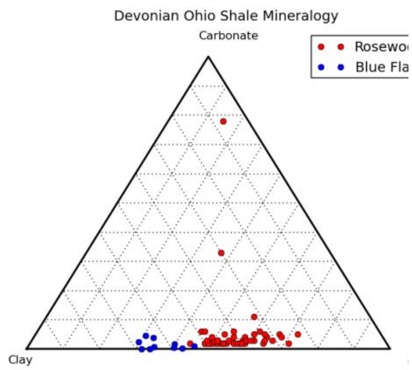
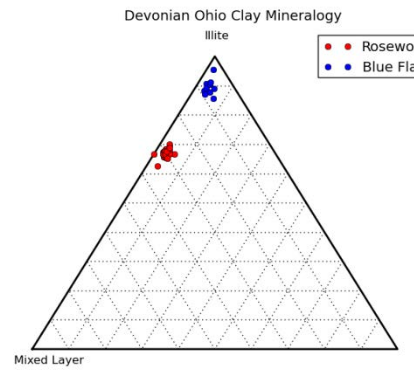


Figure 13. Summary of x-ray diffraction mineralogy of the shale in the Blue Flame #K-2605 Batten and Baird well, Pike County, Kentucky.

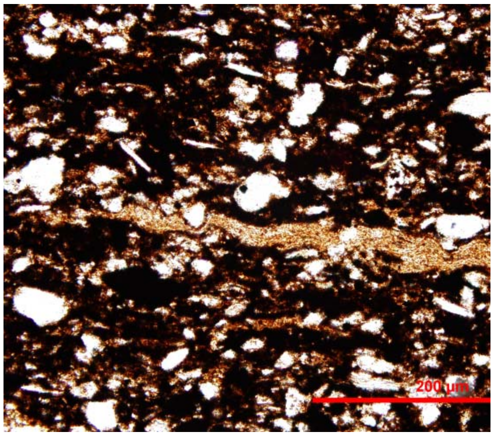


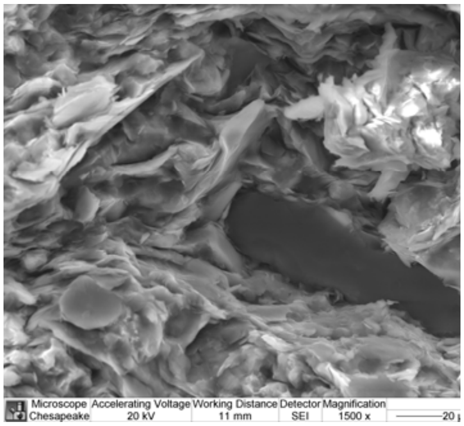


Bulk x-ray diffraction mineralogy

X-ray mineralogy of the clay fraction

Figure 14. Summary of bulk and clay fraction mineralogy in the Rosewood #02 Bargo and Blue Flame #K-2605 Batten and Baird wells.





Tasminites at 4,674 ft, Lower Huron

Bitumen at 4,319.7 ft, Three Lick Bed

Figure 15. Occurrance of organic matter in the Blue Flame #K-2605 Batten and Baird.

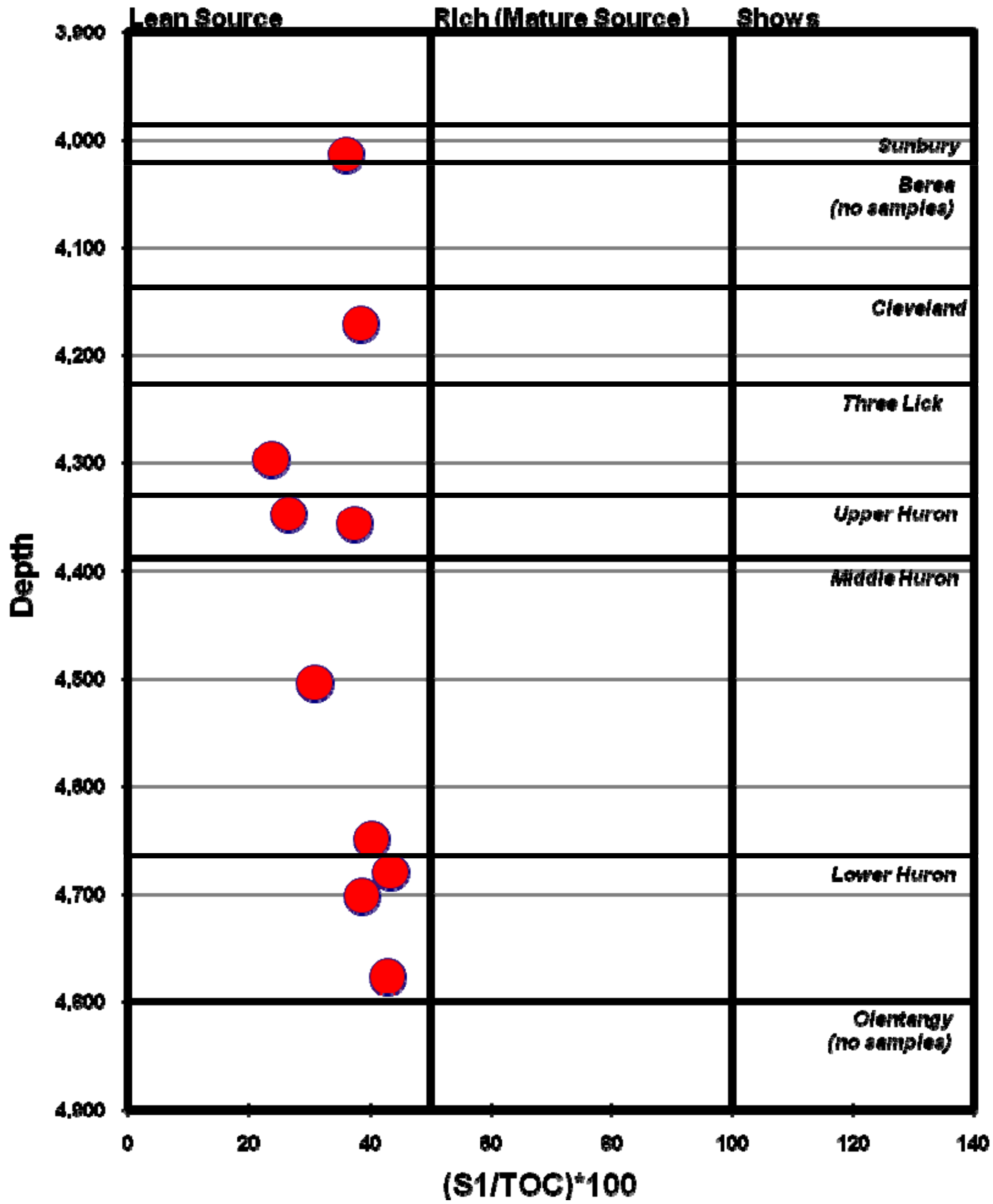


Figure 16. Source rock maturity from Rock Eval for the Blue Flame #K-2605 Batten and Baird.

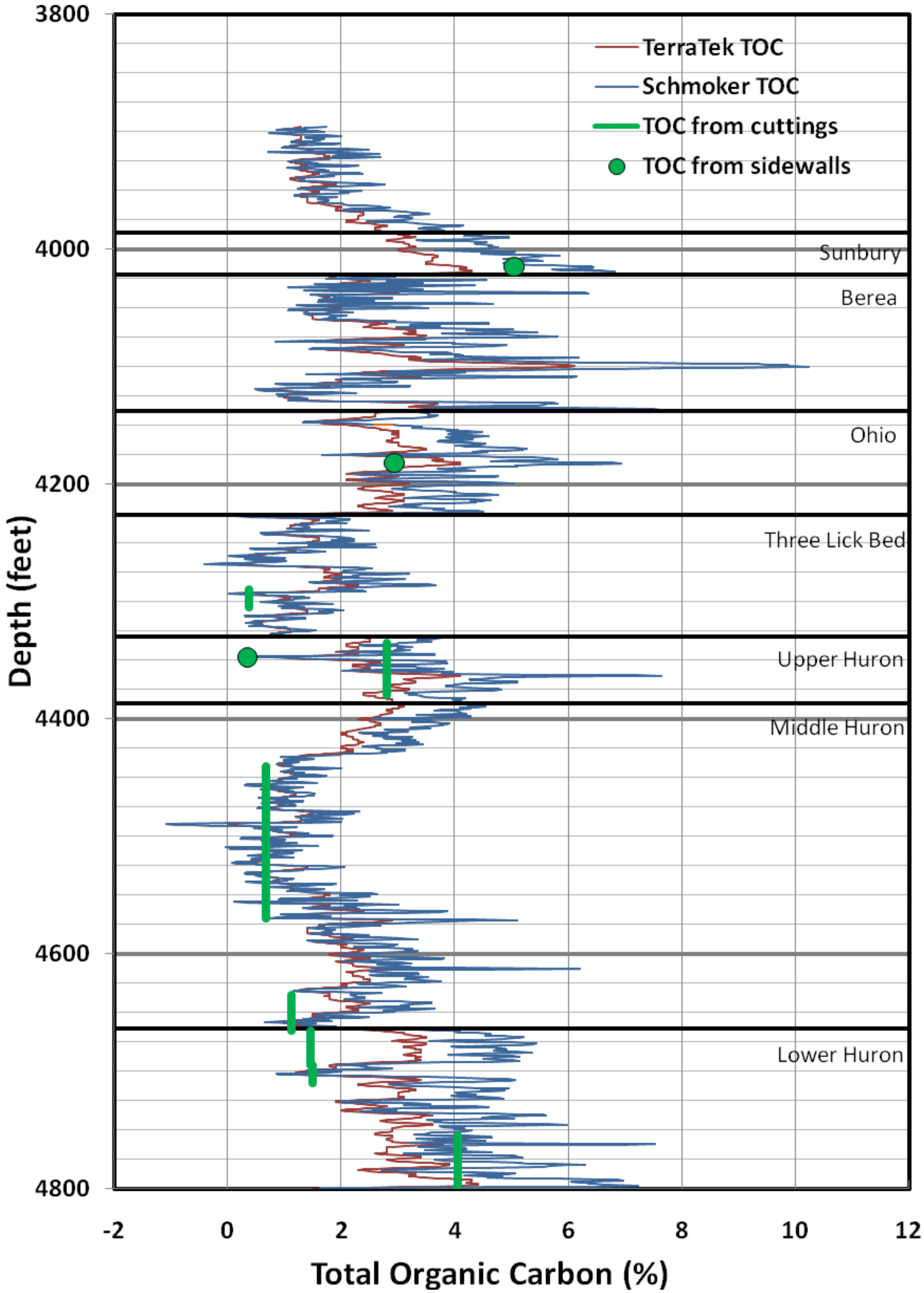


Figure 17. Total organic carbon from well log and analytical data for the Blue Flame K-2605 Batten and Baird well, Pike County, Kentucky.

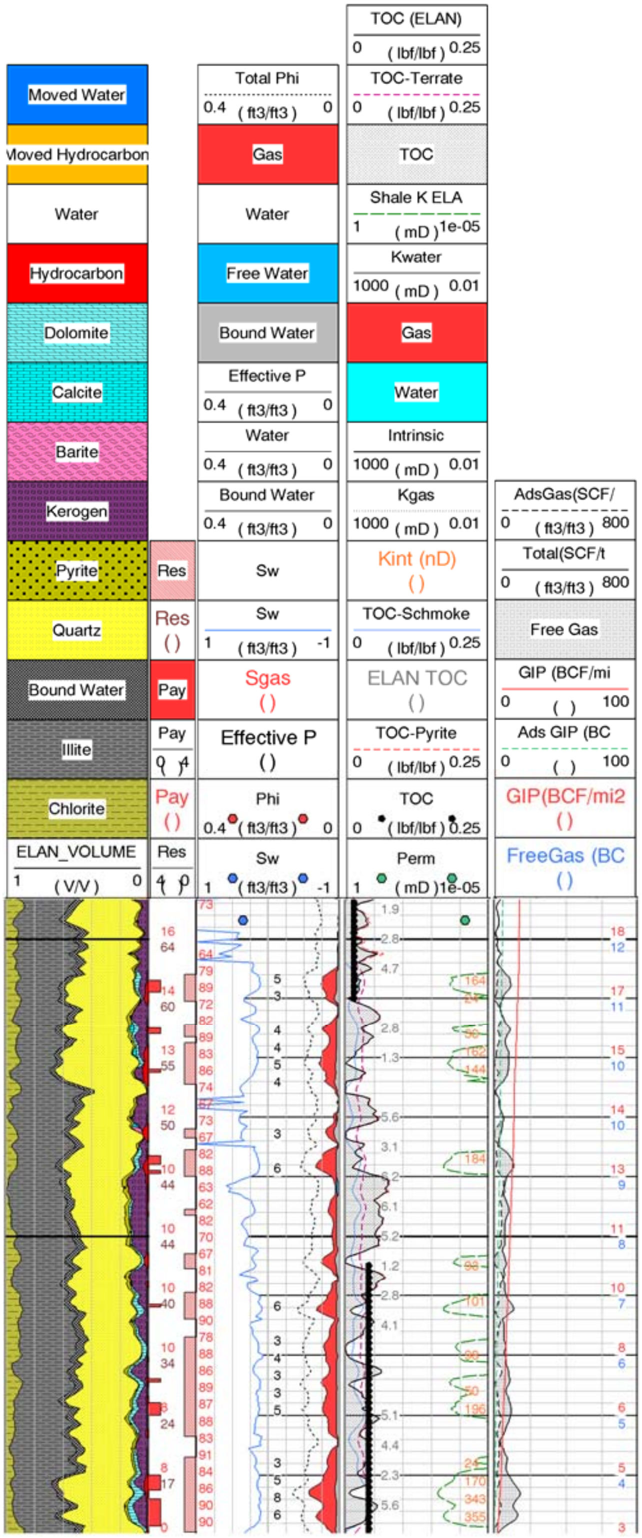


Figure 18. Extracted portion of the processed Schlumberger ECS well montage, shale analysis log through the Lower Huron section of the Blue Flame #K-2605 Batten and Baird well, Pike County showing lithology, estimated adsorbed and free gas, and gas in place calculation.

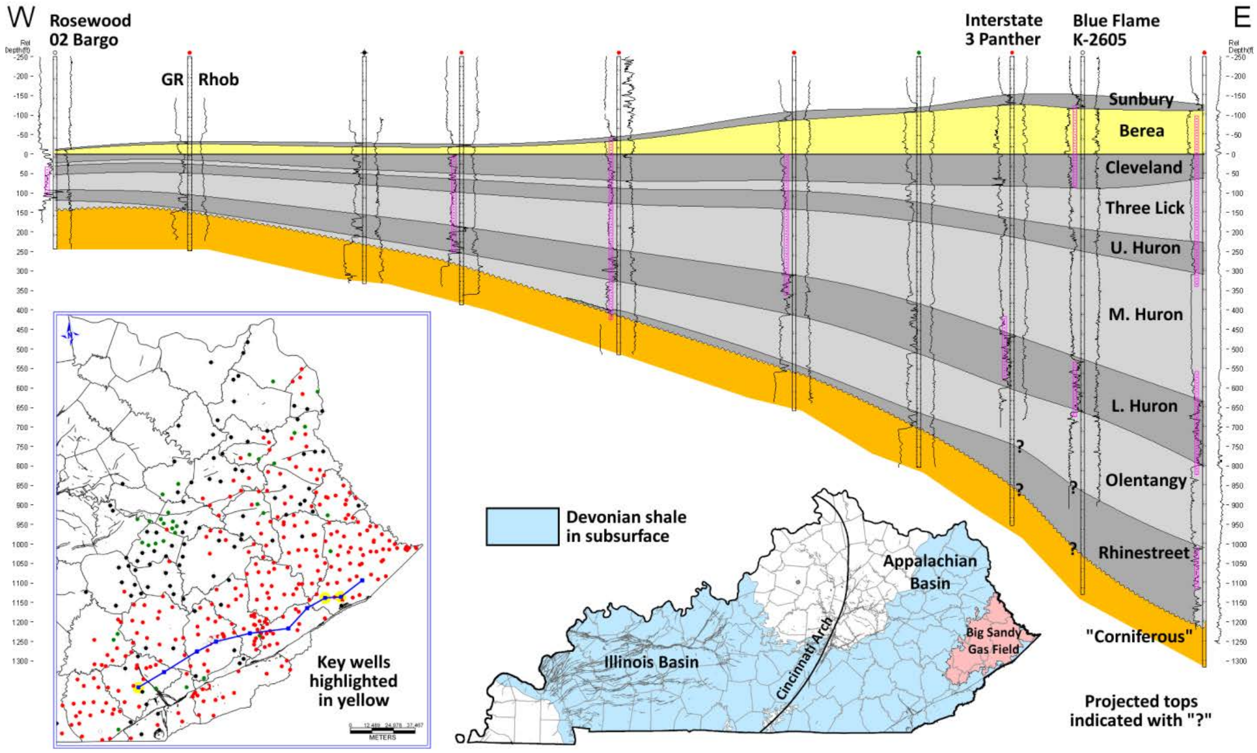


Figure 19. Regional cross section showing stratigraphic relationship of key study wells.

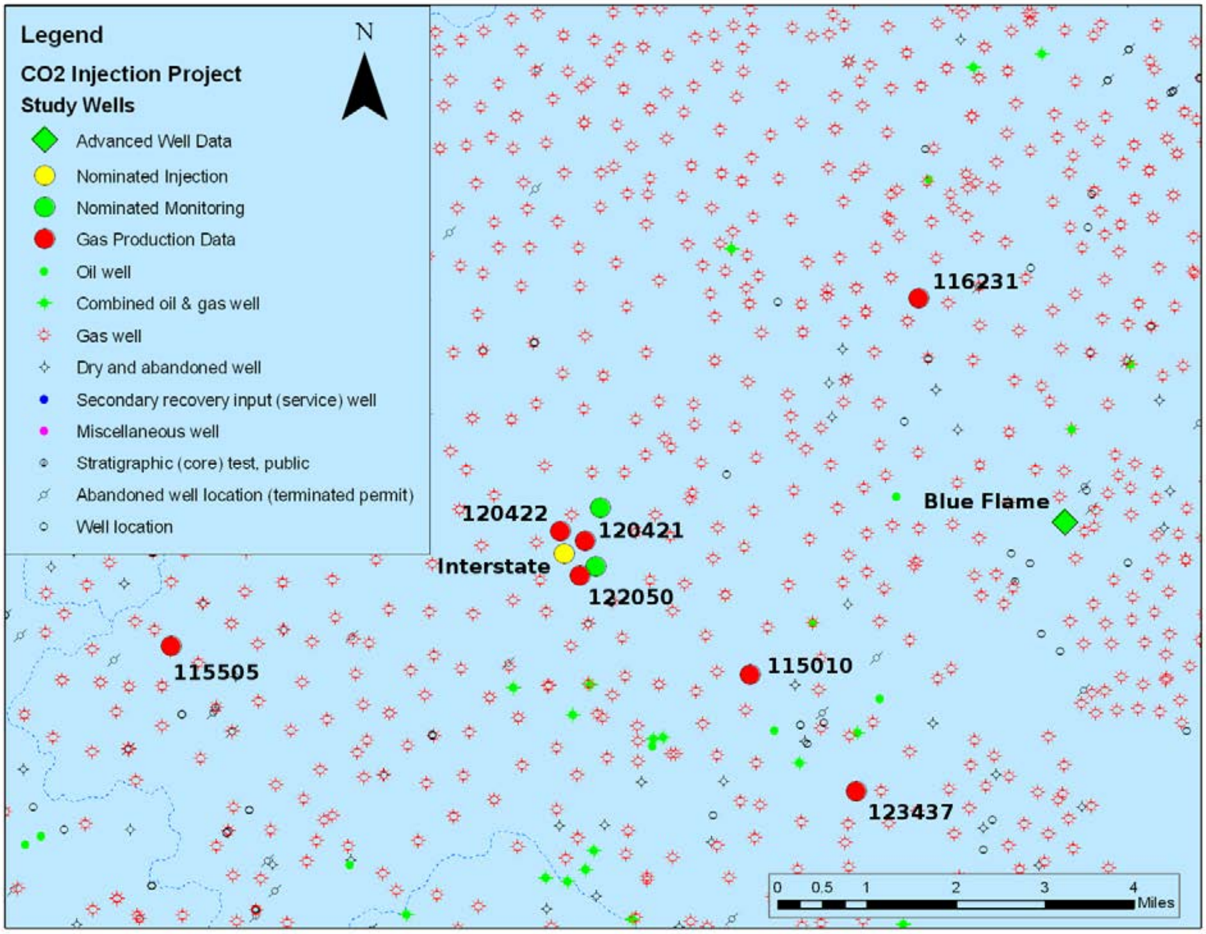


Figure 20. Area of reservoir model with locations of wells with production data for history matching with COMET3.

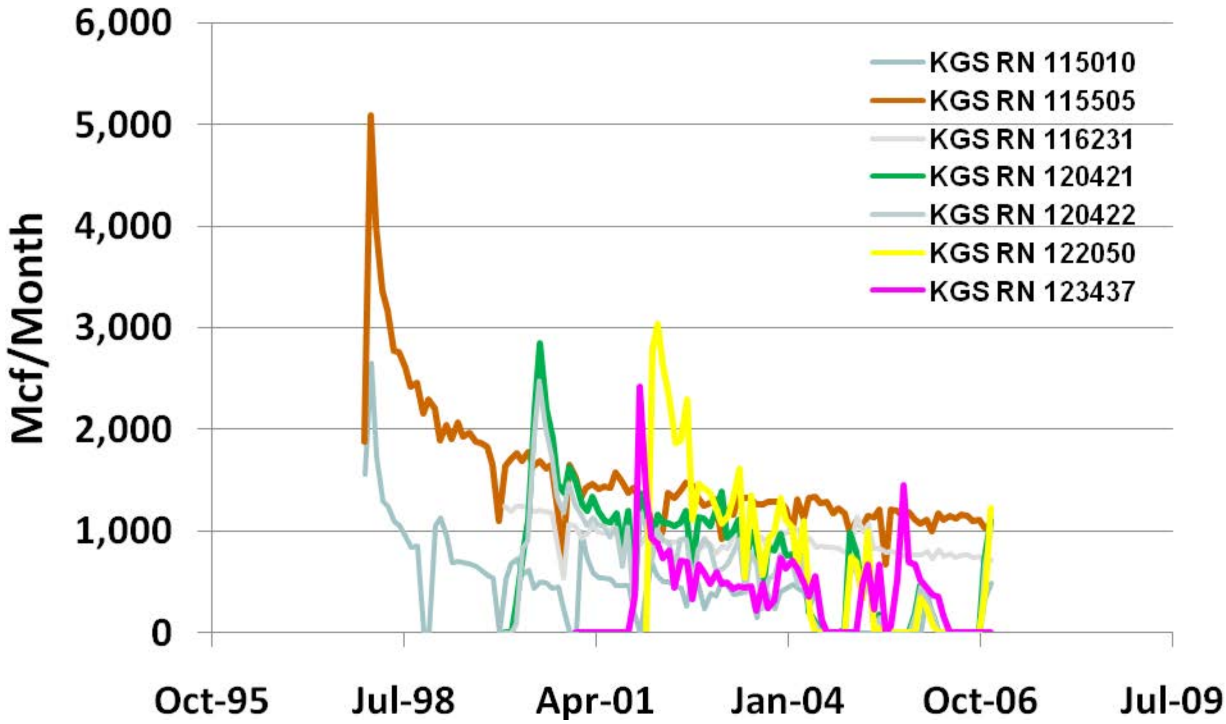


Figure 21. Production data for shale wells used in history match for geostatistical modeling of reservoir.

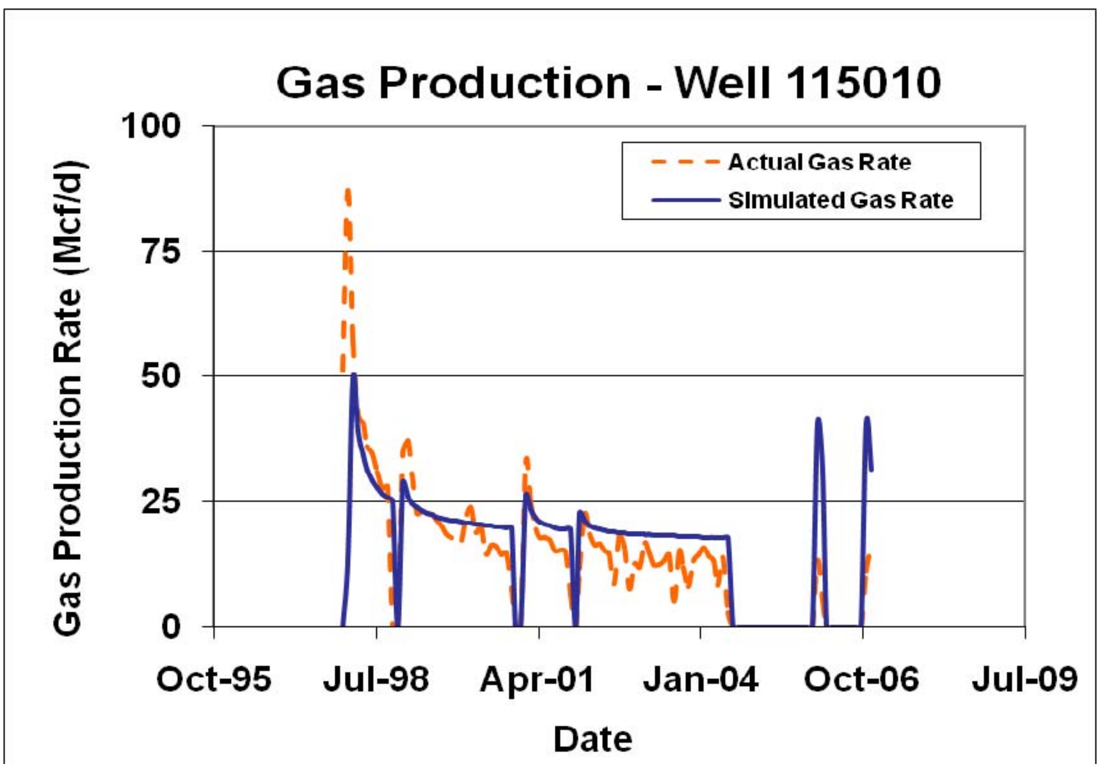


Figure 22. Example shale gas production history match from COMET3, the Blue Flame #K519 Wright, Pike County (Schepers and others, 2009).

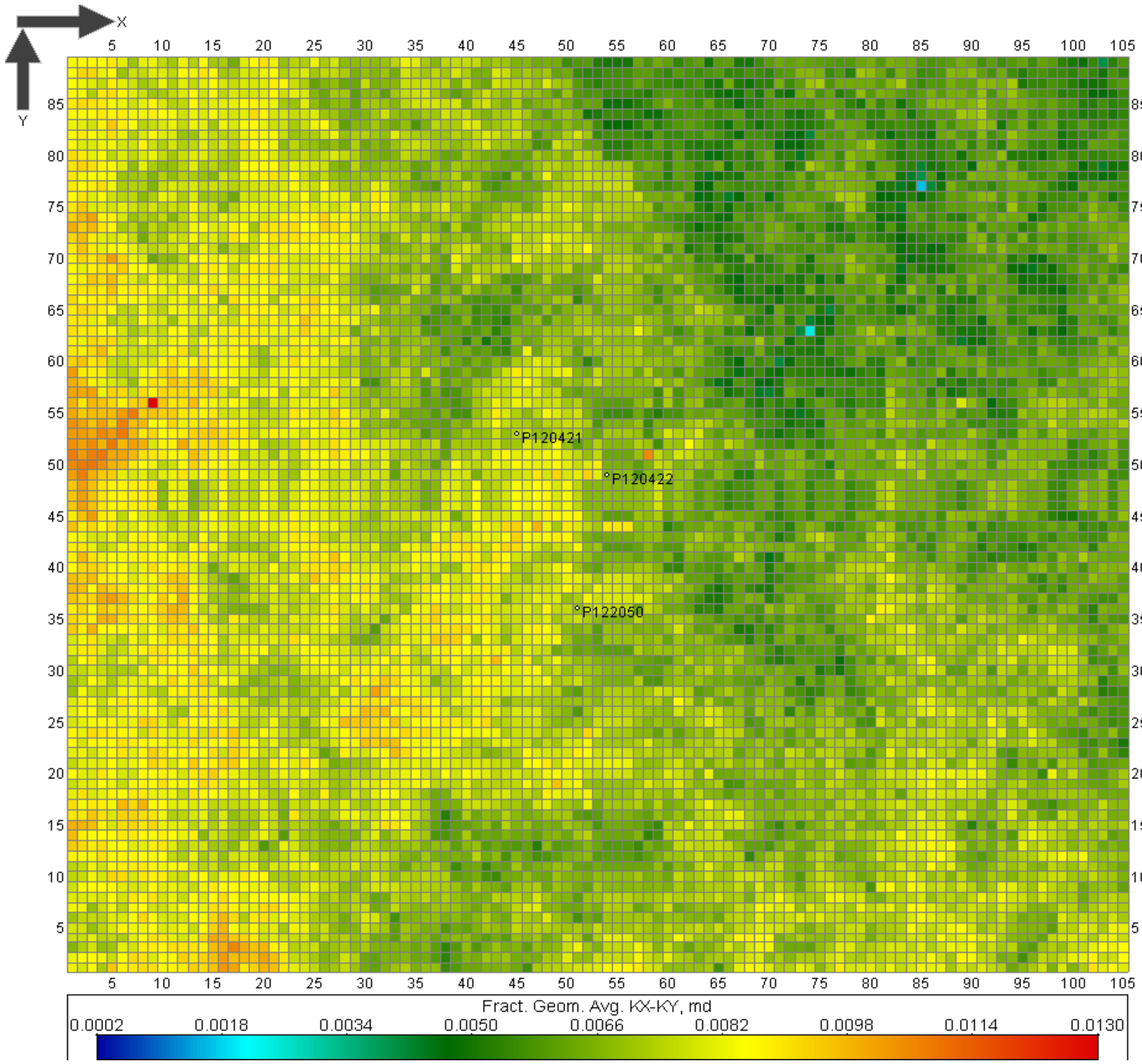


Figure 23. Geostatistical model of distribution of fracture permeability for reservoir simulation (Schepers and others, 2009).

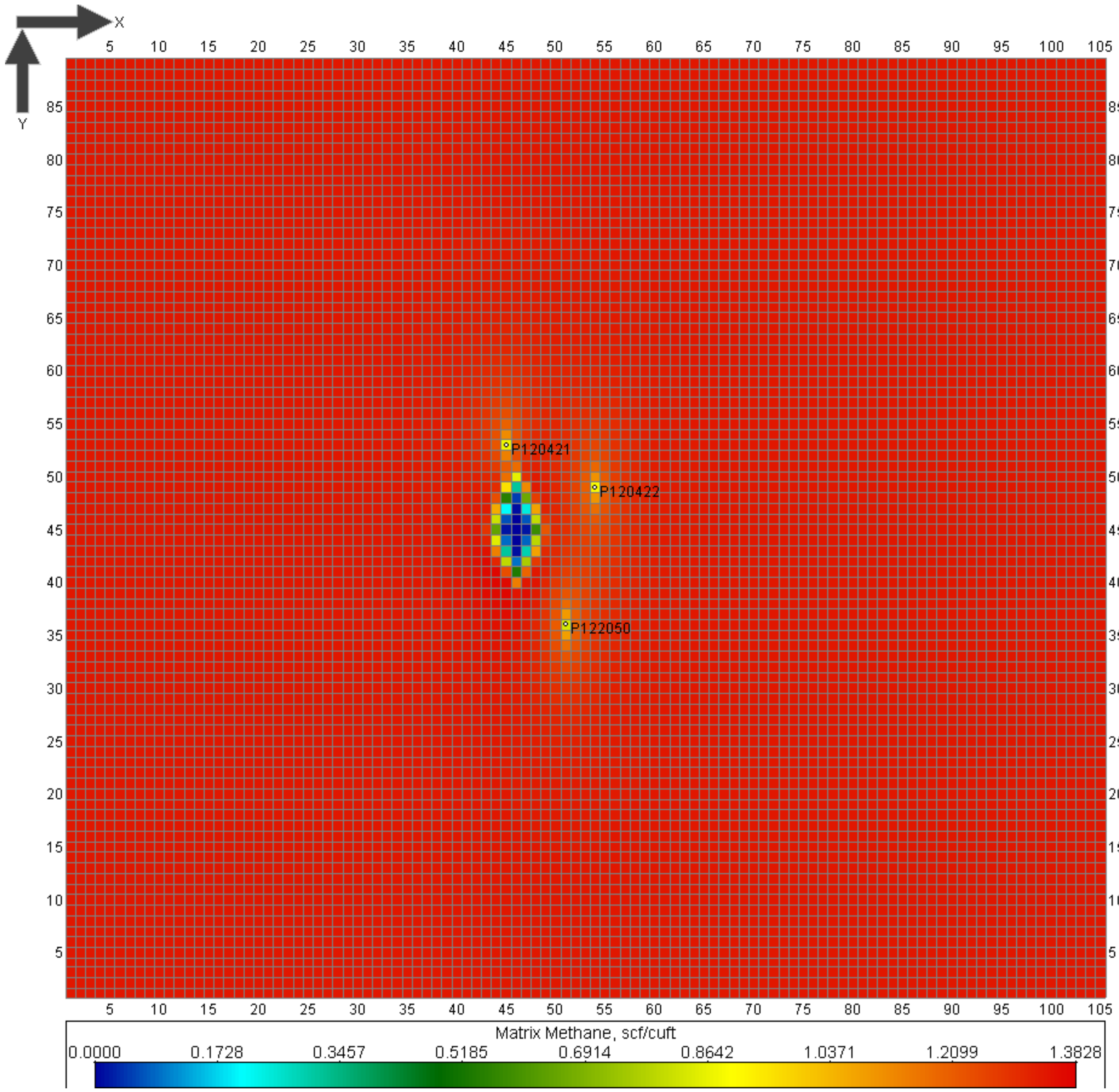


Figure 24. Methane content of fractures (red) with CO_2 plume extension, at full 200 ft simulated thickness, around modeled injection well after 20 years with no breakthrough (Schepers and others, 2009).

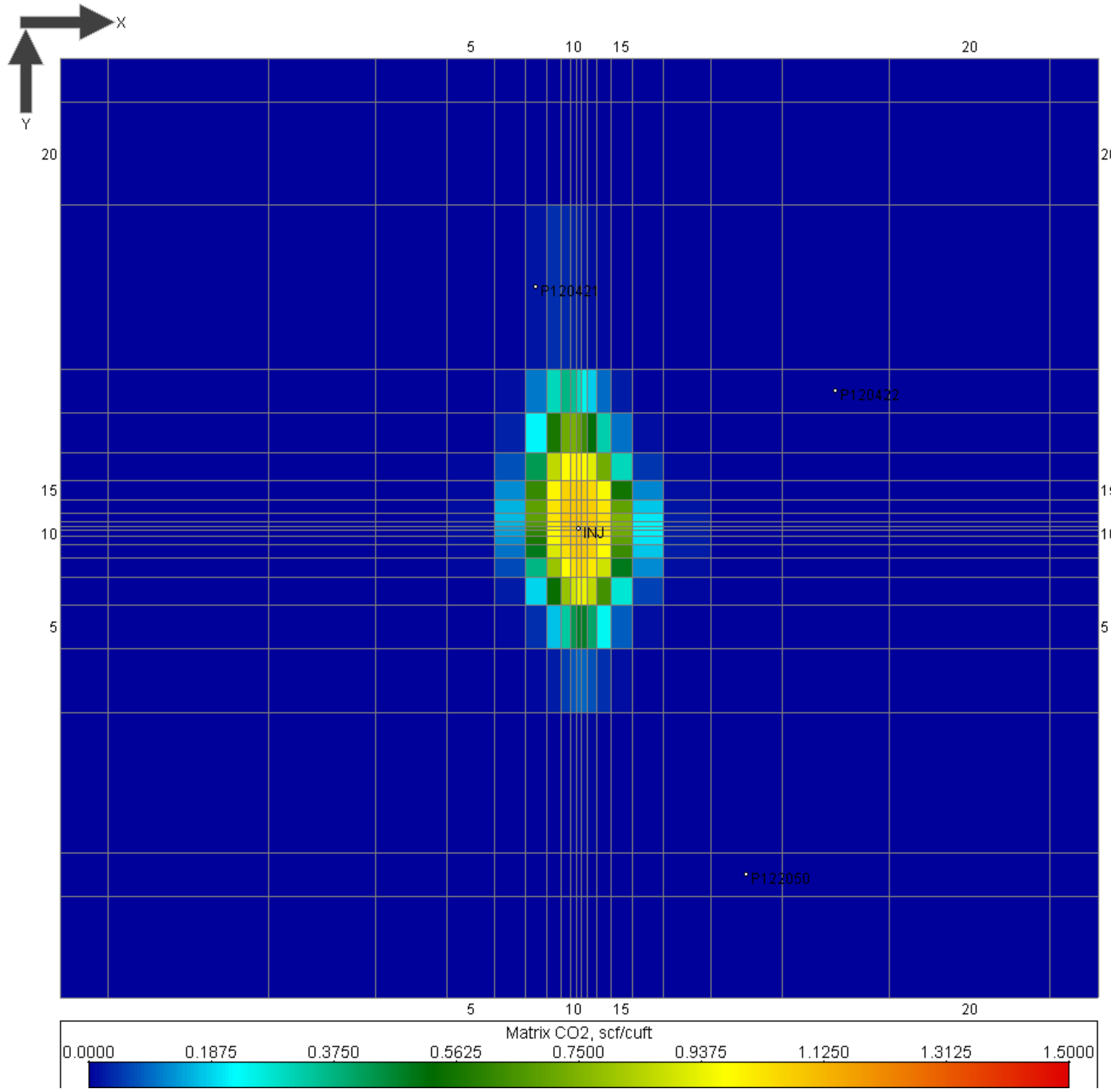


Figure 25. Tenth thickness case (20 ft) of 320 acre pilot injection well design with no breakthrough and projected recovery of 22.8 MMcf gas with continuous injection as compared to 4 MMcf gas recovered in not injection base case (Schepers and others, 2009).

Conversion factors

1 g/cm^3 = 1359.68 tons/acft

1,000 cubic feet of CO_2 = 17.25 tons of CO_2

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Appendix: Identification of key wells used in shale reservoir modeling and simulation

- Interstate #3 Panther Land, API number 1619501718 (KGS record number 102403, permit 80823), 13-J-83, Pike County, total depth 3,636 ft.: cased hole with standard open hole log suite, candidate injection well modeled in simulation
- Rosewood Resources #02 Ted Bargo, API number 1612101449 (KGS record number 130955, permit 99456), 19-E-68, Knott County, total depth 2,238 ft.: advanced shale analysis, well logs, cores, core analysis, gas analysis
- Blue Flame #K-2605 Batten & Baird, API number 161950589 (KGS record number 134470, permit 102566), 11-J-84, Pike County, total depth 5,036 ft.: advanced shale analysis, well logs, rotary sidewall cores
- Blue Flame #K519 Wright, API number 1619503793 (KGS record number 115010, permit 88878), 16-J-84, Pike County, total depth 4,075 ft.: shale gas production data
- EQT #KF3835 EREC, API number 1619503849 (KGS record number 115505, permit 89311), 19-J-82, Pike County, total depth 3,701 ft.: shale gas production data
- EQT #K277DD EREC, API number 1619504017 (KGS record number 116231, permit 89983), 3-J-84, Pike County, total depth 4,165 ft.: shale gas production data
- Kinzer #963 Pike Letcher Land, API number 1619504146 (KGS record number 120421, permit 90454), 13-J-83, Pike County, total depth 4,392 ft.: shale gas production data
- Kinzer #964 Pike Letcher Land, API number 1619504147 (KGS record number 120422, permit 90454), 12-J-83, Pike County, total depth 3,794 ft.: shale gas production data
- Kinzer #1111 Pike Letcher Land, API number 1619504454 (KGS record number 122050, permit 91974), 12-J-83, Pike County, total depth 4,371 ft.: shale gas production data
- CD&G #1 PTC, API number 1619504557 (KGS record number 123437, permit 92648), 24-J-84, Pike County, total depth 4,209 ft.: shale gas production data