RESOURCE ASSESSMENT AND PRODUCTION TESTING FOR COALBED METHANE IN ILLINOIS

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ABBREVIATIONS AND UNITS

CBM	coalbed methane
CMM	coal mine methane
Bcf	billion cubic feet
Tcf	trillion cubic feet
scf	standard cubic feet
t	short ton
scf/t	standard cubic feet per short ton
ft	feet (length)
CH_4	methane
C_{2+}	multi-carbon (or wet) gases such as ethane, propane, and butane
CO_2	carbon dioxide
N_2	nitrogen gas
hvb	high-volatile bituminous
psi	pound per square inch
daf	dry, ash free
dmmf	dry, mineral matter free
R_m	random mean vitrinite reflectance
ISGS	Illinois State Geological Survey
IDCEO	Illinois Department of Commerce and Economic Opportunity
mD	milidarcy units of permeability

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This Open-File document was prepared specifically as a grant report for the Illinois Department of Commerce and Economic Activity, Office of Coal Development. In the interest of timeliness, the text and illustrations have received only limited scientific and editorial review and, therefore, are not expected to meet the normal quality standards of ISGS publications. It has been submitted for formal editorial review and subsequent ISGS publication.

1. ABSTRACT

Three new core holes and a multi-well coalbed methane (CBM) pilot project were drilled to gather coal gas data in Illinois. Two wells (the Hon #9 and Wasem C-1 wells) were located in White County and the third (the Ameren #1-24 well) was drilled in the deepest part of the Illinois Coal basin in Jasper County. The CBM pilot involves a 3 well expansion of the northeast White County Hon #9 core well and included a re-completion of the Hon #3 well and drilling of the Hon #10, and #11, for the purposes of dewatering the coal. Multiple coals were cored in order to determine their gas content, their adsorption isotherms, gas chemical and isotopic composition, and coal petrography and maturation.

Coalbed gas testing of major coals in two new wells drilled in eastern Illinois by the Illinois State Geological Survey (ISGS) indicate potential for commercial production in this evolving play. The James Cantrell, #9 Hon well in northeastern White County cored seven coals totaling 24.5 feet from the Danville through Davis coals at depths from 756 to 1114 ft. Coal gas contents (dmmf) range from 78 to 129 scf/ton. Desorbed gas compositions range from 60 to 82% methane, 16 to 37% nitrogen, and 1.2 to 2.0% CO_2. Methane saturation ranges from 40 to 64%. Pressure transient tests in the Hon #9 coals indicate permeabilities in the 3 to 23 md range. A pilot production program was developed here to evaluate water flush, surfactant flush and conventional hydraulic fracturing completion techniques. Because of multiple Wabash River floods of the pilot site, we were not able to demonstrate CBM production capabilities

In southeastern White County, ISGS drilled 33 feet of coal in the Howard Energy, #C-1 Wasem well and cored 8 coals from the Danville to the Mt. Rorah at depths from 387 to 966 ft. Gas contents range from 75 to 112 scf/ton (dmmf). Desorbed gas compositions range from 69 to 96% methane, 0.5 to 31% nitrogen, and 1.2 to 2.8% CO_2. Methane saturation ranges from 24 to 92%. Carbon and deuterium isotopes suggest the desorbed methane from both the Hon #9 and the Wasem #C-1 wells is primarily biogenic in origin. Possible coal oxidation in canisters may have lowered methane and boosted nitrogen composition values for both wells.

The pilot program drilled in Northeast White County centered on the Hon #9 well, included the re-completion of one previously drilled well and the drilling of two new dewatering wells. Each well was stimulated differently to evaluate different techniques: a) fresh water flush injection and swab back, b) fresh water injection containing a surfactant and swab back, c) conventional hydrofrac with 24/40 size sand proppant, and d) conventional hydrofrac with 10/20 size sand proppant. Based on water production, the well with the surfactant flush and swab back performed comparably to the much more expensive hydrofraced wells. All three performed better than with water alone. Sustained gas production was not obtained because the coals were not pumped long enough. Pumping was shut down twice after the Wabash River flooded our site forcing a shut down and damage of equipment. Thus, it is not believed that the coal reservoir pressure was sufficiently below the critical pressure for the release of gas. At the end of the contract period, no further work was done by the operator.

2. INTRODUCTION

Coal Bed Methane (CBM), a naturally occurring methane gas found in coal seams, is becoming an increasingly important part of our nation's energy portfolio. The most prominent CBM gas producing areas in the U.S., worth multiple billions of dollars, are located in the Rockies (Colorado, New Mexico, Wyoming) with smaller, though active, development in the Appalachians (W. Virginia) and Alabama. Illinois may soon join this group.

Natural gas consumption in the U.S. is expected to reach about 27 trillion cubic feet (Tcf) per year by 2030 from its current level of about 22 Tcf (EIA, 2005). Coalbed methane (CBM) is expected meet a significant portion of the increasing natural gas demand over the next few decades. Proven CBM reserves of the United States have steadily increased from less than 4 Tcf in 1989 to 18.4 Tcf in 2004 and provided 1.7 Tcf of gas production in 2004. As a result, CBM accounted for 9.6% of proven reserves and 9% of production of dry natural gas in the U.S. for the year 2004 (EIA, 2005). Incentives such as federal tax credits, surging gas prices, declining conventional natural gas reserves, mine safety issues, and greenhouse effect of unused coal mine methane released into the atmosphere prompted increased CBM exploration and production activities in the U.S. since mid-1980s.

Coalbed methane development in the U.S. initially focused on the San Juan Basin in New Mexico and the Black Warrior Basin in Alabama. Subsequently, other basins such as the Powder River Basin of Wyoming, the Uinta Basin of Utah, the Raton Basin of Colorado/New Mexico, and Arkoma Basin of Oklahoma have undergone extensive CBM development in the past ten years. Experience with all these basins indicated that gas content, coal permeability and composition, water production and quality, and numerous other factors related to completion of each well must be locally understood within a basin to achieve a successful CBM development.

Where does Illinois fit in the CBM equation? Illinois has the good fortune of being located on top of the nation's largest deposit of bituminous coal, approximately 211 billion tons. To get a handle on the relative scale of 211 billion tons, the mining of coal in Illinois for use in everything from historical home heating to modern day power generation over the past 250 years has consumed just 6 billion tons. At current mining rates of about 30 million tons/year, there is enough Illinois coal in the ground to last hundreds of years. For a variety of reasons and despite vast quantities of coal in Illinois, development of CBM resources has been limited and commercial activity has only recently begun.

In an effort to help spur on the development of the CBM industry in Illinois, the Illinois State Geological Survey (ISGS) has made efforts to characterize the CBM geology of the state. These efforts include studies such as mapping the locations of multiple stacked coal seams, measuring the gas contents of each coal seam, and determining the origin of the methane gas. Even though the origin of the gas sounds like an esoteric parameter to measure, it is actually an important part for determining the most likely places to prospect for CBM. In a simplified explanation, if the methane gas origin, as determined isotopically, is predominately from the thermal decomposition of coal from burial (thermogenic), then prospecting in the deeper coals of Illinois may be better. On the other hand, if the methane gas originates from the byproducts of microbial activity (biogenic), then CBM may be more widespread, being found wherever ground water swept microbes into the coal seams.

In the last decade, there has been increasing exploration and development activity in the Illinois Basin, resulting in some, but so far very limited, CBM production in the basin. Demir et al. (2004) reviewed the basic aspects of CBM and previous work on coal and CBM resources of Illinois, and discussed their findings from a two year (2001-2003) project that involved drilling five wells, gas content measurements, coal characterization, and digital mapping. The goal of the current project (2004-2007) reported here was (1) to drill new three stratigraphic test wells to generate additional basic data to supplement data from the five wells discussed by Demir et al. (2004) and (2) to test CBM production from a pilot project built around one of the three wells.

3. BRIEF TECHNICAL BACKGROUND

Coal is derived from plant material deposited in ancient peat swamps and then altered through geochemical processes. CBM may contain a mixture of gases, but methane (CH_4) gas almost always the dominant fraction in the mixture. Two distinct processes give rise to CH_4 in coal: biochemical processes (biogenic CH_4) and thermal processes (thermogenic CH_4). Biogenic CH_4 is the byproduct of the biochemical degradation of organic material early during the peat stage or later during the exposure of coal to bacterial activity. The early-stage biogenic CH_4, which is referred to also as swamp or marsh gas, is generated through a complex and often poorly understood process involving many species of bacteria and many different combinations of chemical reactions. Most of the early-stage biogenic CH_4 probably was expelled from the peat into the atmosphere. Biogenic CH_4 can be generated also after coal is formed and then exposed to bacterial activity through ground water circulation. Tectonic uplift, erosion, and sufficient permeability after burial and coalification can facilitate the circulation of bacteria-bearing meteoric waters through coal beds. This late-stage or secondary biogenic methane probably comprises most of the biogenic CH_4 retained in coal. Thermogenic CH_4 is generated when coal or its precursor material are subjected to thermal alteration as a result of increasing burial over geologic time or exposure to heat from magmatic sources. The thermal effect is responsible also for coalification, a process by which peat is gradually converted to lignite, sub-bituminous coal, bituminous coal, and then to anthracite. Starting with high-volatile bituminous coal stage, the thermogenic CH_4 generation increases rapidly with increasing rank.

Coal is different from conventional natural gas reservoirs in that it is both the source rock and reservoir rock for CH_4 gas. In addition, gas generated during oil formation in strata lying well below the coal seams could migrate upward and be stored in coal seams. Increasing aromaticity of coal during coalification increases its microporosity and internal surface area which, in turn, are desirable for retaining CH_4. In contrast to conventional natural gas reservoirs, coal has very little macroporosity. This macroporosity is found primarily in orthogonal natural fractures or “cleats” that form in the coal. It holds some free CH_4 gas and acts as the main permeability pathways to deliver desorbed gas to a well or mine void. However, most of the CH_4 is present not as free gas but as a condensed gas monolayer that is physically adsorbed on to the micropore walls through weak Van der Waal's forces. As a result, at a given pressure and temperature coal can hold much more CH_4 than an equivalent volume of a conventional gas reservoir rock such as sandstone. Once formed, the CH_4 gas in coal is held in place by reservoir hydrostatic pressure in addition to the Van der Waal's forces.

The ISGS CBM corehole sampling program, begun in 2001, brought extensive new data to the public that has encouraged and focused private industry exploration for CBM. Cumulative coal thicknesses, the thicker the better, compiled for the seven major coal seams in Illinois, range from 10 to over 35 feet thick, with the greatest thickness of coal located in eastern and southern Illinois. As measured so far, the gas contents of Illinois coals range from 50 to over 170 cubic feet of methane per ton of coal (50 to 170 scf/ton), averaging about 100 scf/ton. Of interest is the consistent biogenic isotopic signature of methane gas extracted from our coals, because this would imply a widespread occurrence of the gas.

Currently, a large CBM development project is underway in Saline County, IL extracting CBM from coal seams at a depth of 500 to 800 feet. Single coal seam well production rates range from 10 thousand cubic feet per day (10 mscf/day) to over 50 mscf/day. At today's natural gas prices and the shallow depths of extraction, these appear to be economically viable. The additional expense of removing unwanted non-combustible coal seam gas, such as nitrogen (2% to a rare 20% of total gas) and CO_2 (1% to 3%) must be considered in order to meet pipeline specifications.

Future improvements include multi-seam completions, which have been done and have shown improved yields, and horizontal wells, which have been permitted in some areas but with unknown results. With 284 billion tons of coal resource (211 in Illinois), the Illinois Basin in-place CBM is estimated at 21 to 25 trillion cubic feet (tcf). Because of the abundance of biogenic methane, CBM exploration is not limited to the heart of the basin, but can extend to shallow depths near the basin edge. In fact, the southern and eastern edge of the Illinois Basin consistently show higher gas contents, thicker net coals, and have been the location of commercial exploration and development.

4. PAST WORK ON ILLINOIS COAL AND COALBED METHANE RESOURCES

4.1. Coal Resources of Illinois

Potential for commercial quantities of CBM in the Illinois Basin is based on the fact that the Basin has huge coal reserves. Coal-bearing rocks of the Illinois Basin are Pennsylvanian age and underlie about two-thirds (36,800 square miles) of Illinois and lesser areas of Indiana and Kentucky (**fig. 1**). The thickest and most extensive coal seams in Illinois are found in the Middle Pennsylvanian Carbondale Formation. Total aggregate coal thickness locally may exceed 40 ft. The Illinois Basin coals are of high-volatile bituminous A, B, and C ranks; the lowest rank coals are located in northwestern Illinois, and the coal rank generally increases towards southeastern Illinois. Total coal resources of the Illinois Basin are ~290 billion tons, 211.4 billion tons of which are in Illinois. More than half of the major coal deposits in Illinois lie at depths of less than 525 ft, and only small portions of the deposits are greater than 1300 ft deep. Among 75 known seams in the Basin, 27 are thick and extensive enough to have been mapped, but 99% of the resources occur in just 9 seams (ISGS, 2006), namely Danville, Jamestown, Herrin, Springfield, Colchester, Seelyville, Dekoven/Davis, Murphysboro, and Rock Island coals. 85 to 90% of coal production in Illinois is from Herrin and Springfield coals.

4.2. Methane Gas in Illinois Coals

Illinois mines were the sites of many mine gas explosions in the past due to methane release from coal. According to desorption data published prior to 2001 and cited in Demir et al (2004), the gas content of Illinois coals were 8 to 125 standard cubic feet per ton (scf/t); these values would be a little lower if adjusted to 60 ^{o}F (the standard temperature used in more current calculations) from 77 ^{o}F commonly used in the past publications. However, more recent measurements by Demir et al. (2004) suggested that Illinois coals may contain 25 to 100% more CBM than previously thought; many coals in Clark and Franklin counties had gas contents of 100 to 173 scf/ton on a dmmf basis. Furthermore, measurements made a few years ago indicated relatively high quantities of methane release from active Illinois mines (Demir et al., 2004). In spite of the large resources, commercial coal gas production in Illinois before 2005 consisted of only relatively small amounts of production of abandoned coal mine methane (CMM) until two mid-size CBM development projects, one in Sullivan County in Indiana and the other one in Saline County in Illinois, started producing from unmined, virgin coal seams, and a CMM project was begun in Franklin County, Illinois. Recent advances in exploration and production technologies and rising gas prices have stimulated more interest in producing CMM and CBM in the Illinois Basin. As of 3/31/07 there have been at least 340 permits for CBM and 156 permits for CMM related wells in Illinois since 1986. **(Figures 2a & b)**

5. METHODS

5.1. Drilling, Coring, and Logging

Three new data wells were drilled, cored at coal-bearing intervals, and subsequently logged for the current project. **Table 1** shows location and sampling information on these three wells, and **Appendix 1** gives description of the cores from the wells. Data from these wells form the bulk of this report.

The first well, the Jim Cantrell, Hon #9, was drilled in Sec 9, T4S, R14W, to a depth of ~1,120 ft in the New Harmony Oil Field in White County, IL, in October 2003. This well provided core data for the area and became the center well for the production pilot. Sixteen coal samples and three black shale samples were taken from these cores for gas content and other analyses. A near-by well, Hon #3, was re-completed in the coal strata and just to the west the Hon #10 and Hon #11 were drilled and completed in the same strata.

The second well, the Howard Energy, Wasem #C-1 well was drilled in Sec. 24, T7S, R10E in July 2004 to a depth of ~1,030 ft on a Howard Energy Company lease in southeastern White

County in July 2004. From the cored intervals fifteen coal and two black shale samples were taken for gas content and other analyses. With cored coals and an additional 6.5 ft of uncored coal in four seams identified from logs, over 35 ft of cumulative coal thickness were calculated for this well, making it one of the thickest coal occurrences in the State.

The third well, the Peabody Natural Gas LLC, Ameren #1-24, was drilled in Sec 24, T6N, R8E to a depth of 1,500 ft in April 2005 on Newton Power Plant property located in Jasper County, IL. Sixteen coal and four black shale samples were utilized for gas content, adsorption isotherm, gas chemistry and other analyses. This is the deepest stratigraphic test well the ISGS has drilled so far for CBM evaluation.

5.2. Determination of Gas Content and Related Parameters

The same procedures described in Demir et al (2004) were followed to determine gas contents of the coal core samples, chemical and isotopic (^{14}C and Deuterium) compositions of the desorbed gases, petrographic compositions of the coal samples, and methane adsorption isotherms of the coals.

6. RESULTS AND DISCUSSION

6.1. Field and Laboratory Data on Stratigraphic Test Wells

6.1.1. Gas Contents of Coal and Shales

The results of gas content measurements and coal chemical analyses are given in **Table 2** and in **Appendices 2 and 3.** The gas content of the coal samples ranged from 41 to 159 scf/t on a dmmf basis (**Table 2, fig. 3**) with an average of 100 scf/t and a standard deviation of 23 scf/t. Shale gas contents ranged from 4 to 37 scf/t on an as-received basis and from 97 to 164 scf/t on a dmmf basis. Areas around these three wells have a good potential for CBM development because many seams in the wells have gas contents of ~100 scf/t or more. There is a reasonable correlation between gas contents on an as-received basis and on a dmmf basis for coal samples (**fig. 4**), which can be used to estimate dmmf gas contents from as-received gas contents when mineral matter and moisture analyses of coals are not available.

As stated in Demir et al. (2004) the gas contents obtained from canister desorption tests should be considered as minimum gas contents. It is possible that leaking along fractures created by mechanical stress of drilling and flushing of the core by constant drilling fluid circulation during cutting of the cores could remove some gas. Such gas losses are not accounted for by the current measurement techniques. Therefore, actual in-situ gas contents of coals in the ground are likely to be somewhat greater than those obtained from canister tests. The maximum gas a coal might hold can be determined from adsorption isotherms; the actual coal gas content probably lies between the desorption and adsorption values. However, canister tests are still essential for getting a standardized gas content value, helping to determine the regional and local gas content variations, and calculating minimum reserves.

6.1.2. Coal Petrography and Thermal Maturity

Petrographic analysis of the coal samples was made by Dr. Maria Mastalerz of the Indiana Geological Survey. Volumes of total vitrinite, desmocollinite (a vitrinite component), liptinite, inertinite and mineral matter and a measure of average vitrinite reflectance were determined from polished coal samples from each desorbed coal interval (see **Table 3**) . The multiple coal samples in a single well commonly showed considerable variation in the organic components, called, "macerals", in the coal. In general, Illinois Basin coals have a high vitrinitic volume with less intertinite and then even less liptinite. In the Hon #9 well, the coals ranged from 67 to 89% by volume vitrinite, 2 to 18% inertinite and 1.8 to 14% liptinite. Coals in the Wasem #C-1 well ranged from 72 to 92% vitrinite, 1.4 to 155 inertinite, and 2.8 to 9.9% liptinite. Coals in the Ameren #1-24 well ranged from 65 to 90% vitrinite, 3 to 19% inertinite, and 2 to 7% liptinite. Mineral matter includes pyrite, calcite, clay, quartz and clay-rich silt that do not adsorb or release methane. Hi mineral matter will be found in coals that have densities greater than 1.35 g/cc. Samples of coal from the Hon #9 well contained 0.4 to 18% mineral matter. The coals from the Wasem # C-1 well contained 0.8 to 9% mineral mater. Those from the Ameren #1-24 contained 1 to 32% mineral matter.

Average vitrinite reflectance, measured as the average of many measurements of the percent of light that is reflected off a polished fragment of vitrinite, is a measure of the thermal maturity of the coal. In a single well, increases in vitrinite reflectance will be seen with increasing depth of burial of the coal. Regionally, vitrinite reflectance increases with coal rank and thus may increase toward southeastern edge of Illinois as coals pass from predominantly High Vol Bituminous B in the central Illinois Basin to High Vol Bituminous A in rank in the very southeastern corner of the state. The coals in the Hon #9 have an average vitrinite reflectance of 0.569%, the Wasem #C-1 at 0.605% and the Ameren #1-24 at 0.605%. These values are in the earliest part of the thermal window to generate hydrocarbons. Isotope data shown below will indicate that only the Wasem and Ameren wells have a very small component of thermogenic gas. All the wells have a predominant biogenic methane component.

6.1.3. Intra-Well Gas Content Variations

Gas content can vary from one seam to another in given well (**fig. 2)**, although not always systematically. Even within the same seam in a given well there are some variations because of the heterogeneous distribution of macerals and minerals in the coal (**Table 3, Appendix 2).** Although deeper coals generally had higher gas contents than the shallowest coals in Hon #9 and Ameren#1-24 wells, the opposite was true for the Wasem#C-1 well (**fig. 5**). This cannot be explained by rank as there was no noticeable correlation between the gas content and vitrinite reflectance **(fig. 6)**. It is probably related to changes in microbial gas generation and in gas loss or entrapment influenced by geologic structures and hydrological flow patterns, which were likely different for different coals. Therefore, the details of local hydrogeological, structural, and stratigraphic conditions must be understood to explain the gas content variations among different seams in a given well.

6.1.4. Inter-Well Gas Content Variations

Danville, Herrin, Springfield, Survant, and Davis/Seelyville seams were present in all three test well locations. The gas content of each coal seam tends to be higher at greater depths than in shallower depths (**fig. 7**) although the vitrinite reflectance does not vary systematically with depth (**fig. 8**) or gas content (**fig. 9**), suggesting a greater importance of hydrostatic pressure for helping hold more gas in place at greater depths than at shallower depths. However, Demir et al. (2004) reported a correlation between vitrinite reflectance and gas content in other wells they drilled. Thus, if more wells in different areas are considered, vitrinite reflectance (rank) may still be one of the important indicators of the gas content of a given coal seam in Illinois. Another variable that needs further investigation is the role of and proximity to methano-genic bacteria.

6.1.5. Gas Composition and Origin

Coal gas samples obtained from the canisters contained 57 to 89% combustible gases (**table 4, fig. 10**), and the combustible gas contents of shale samples were between 34 to 71%. Most of the combustible gas in the coals was CH_4. Other combustibles, which are higher molecular weight hydrocarbons (C_{2+}, or wet gases), made up 0.00 to 1.83% of the total gas. These values yielded a gas dryness index (GDI) of 0.98 to 1.00, making the combustible gases classified as dry (GDI=0.94-0.98) to very dry (GDI>0.99). The non-combustible gases in the mixture were mostly nitrogen (N_2) at about 11 to 42% and lesser amounts of carbon dioxide (CO_2) at about 1 to 3%. It should be noted that ambient air trapped in the canister when it was sealed might not have been fully displaced fast enough to prevent partial oxidation of the coal. The partial oxidation of the coal cores in the canisters probably left behind some nitrogen gas that was counted as coal gas nitrogen instead of air nitrogen during analysis. This means that actual nitrogen contents may be somewhat lower and actual combustible gas contents somewhat higher than the corresponding values given in **table 4** and **figure 10.**

The isotopic compositions (δC^{13} and δD values) of the CH_4 fractions of the desorbed gas samples (**table 4**) were used to determine the origin of the gases. The results (**figure 11**) revealed that CBM in these three wells formed primarily by microbial processes involving CO_2 reduction with the possibility of small contributions from thermogenic processes. A mixed origin, instead of predominantly biogenic origin, is inferred based on plotting C_{2+} hydrocarbons against δC^{13} of methane (**fig. 12**). Isotopic values of the shale gases also plot in the microbial field or in the transition zone (**figs. 11, 12**) suggesting that gas from the coals and shales were generated similarly.

6.1.6. Minimum Gas Saturation in Coal Seams

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

Methane adsorption isotherms of the cored coals (**figs. 13a, 14a, 15a)** were used to determine the variability of gas storage capacity with pressure. The methane gas saturations of the coals at the calculated reservoir pressures ranged from about 15 to 87% (**table 5, fig. 16**). As a result of using pure methane, instead of actual coal gas composition, in the production of the adsorption isotherms, the calculated gas saturation values may be a little low but probably still not too far from the actual values.

Gas adsorption isotherms along with measured gas contents are used to determine the initial hydrostatic (reservoir) pressure at which CBM can be produced from a coal seam. This pressure is also called the critical pressure. For example, based on the sample #1 data of the coal from the Davis seam in Hon #9 well, the estimated reservoir pressure is ~480 psi based on a normal fresh water hydrostatic gradient; and the coal has a daf gas content of 115 scf/t at about 54% gas saturation (**fig. 13b, table 5**). However, the isotherm shows that the minimum reservoir pressure (also called the critical pressure) that can hold 115 scf/ton in place is 178 psi. Thus, assuming reasonable permeability, the hydrostatic pressure of this coal seam must be reduced below the 178 psi critical pressure by pumping out the formation water in order to begin the production of free gas from the seam. However, pressure on Danville Coal in Wasem#C-1 well, which has 87% gas saturation (based on sample #1 data of the coal), must be reduced by only ~30 psi to start desorbing the gas (**fig. 14b**). In Ameren#1-24 well, more than 375 psi drop is required to desorb the gas from Seelyville Coal based on the data on the Seelyville sample #1, which shows a gas content of ~159 scf/t and a gas saturation of 62% at ~647 psi reservoir pressure (**fig. 15b, table 5**).

6.1.7. Permeability Testing

Pressure Transient Analysis can be used to determine the in-situ reservoir permeability of a target coal seam utilizing water injection/falloff tests, which are very effective and efficient for testing water-saturated coal seams. In the past, injection/falloff tests were performed in the oil fields on water disposal or waterflood injection wells to estimate permeability to water, skin damage, and in some cases reservoir geometry. Injection/falloff tests are used to estimate permeability and skin factor on wells that will not flow naturally such as coalbed methane wells. It is imperative that the test be performed without exceeding the fracture gradient of the formation in order to obtain accurate analysis results. In lower permeability reservoirs, very low injection rates of 0.2 to 2.5 gallons/minute are often required to prevent fracturing. This is nearly impossible to perform with larger stimulation-type pumping units, thus the PermPT concept was born. Pinnacle Technologies Company was subcontracted to conduct our tests. They built a fit-for-purpose high pressure, low injection rate unit capable of precisely metering small volumes of water into a formation without exceeding fracturing pressure, while measuring well pressure at the surface and down at the level of the coal. They have previously conducted such tests throughout the Midwest.

Full analyses on the pressure transient tests by Pinnacle Technologies are included in **Appendix 5a and 5b**. Results are summarized in **Table 6**. Tests in the Hon #9 were conduced in six different coal seams. Permeabilities determined from the test data ranged from 3.3 to 33.7 md.

Tests in the two coals in the Hon #3 well had difficulties and only one test was considered valid, indicating that the Herrin Coal had 0.99 mD permeability.

6.1.8 Produced Water Composition and Volume

Two water samples were obtained from the Hon #9 well in August 2004. This water was pumped from the well and sampled at the well-head and consisted of NaCl salty water with 14,000 ppm chlorides and a total dissolved solids of 23,000 ppm. Minor components included 5 to 32 ppm SO_4 and 42 to 44 ppm Br. Phosphate, nitrate and fluoride contents were less than 1 ppm.

6.2. Pilot Production Project

The pilot project for testing CBM production in White County was designed to create a five spot pattern with Hon #9 well in the center as a mainly gas production well and four wells around it to be used mainly as dewatering wells (**fig. 17**) . NE-SW trending normal faults of Wabash Valley fault system are within two miles to the west and east of the pilot project. The area lies on a low relief anticline that has Mississippian age oil reservoirs. A Herrin Coal structure map **(Fig. 18)** shows the gentle structure in the area. As mentioned earlier, the Hon #9 well was drilled in October 2003 in. After drilling, coring and logging, the Hon #9 well was cased with 5 1/14" pipe from the base of the hole to the surface.. One of the dewatering wells, Hon #3, was re-completed in November 2003 from an old plugged well that formerly produced from a deep Mississippian pay. Royal Drilling Company re-entered the 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 through the coal zones. Correlations to the Hon #9, which lies about 700 ft to the north-northwest, are shown in the NW-SE stratigraphic cross section (**fig. 19)** using the old SP-Resistivity log available from the Hon #3 through the GR-Den log from the Hon #9 to the GR-Den log in the Hon #11.

First, the Hon #9 was put on pump to test the dewatering of the coals in this single well. This well had been perforated on 4//30/04 in the Danville, Herrin, Springfield, Survant and the Davis/Dekoven coals. A summary chart of the average daily flow rate and the cumulative water production are shown in f**ig. 21a.** In June 04, the well was put on pump to see what would happen. Once the coal fines were removed, average water recovery ranged from 3 to15 barels/day. Small amounts of flammable gas were produced, but they would not sustain a flare.

In mid-November 2004, 120 barrels of fresh water with one 55 gallon barrel of a surfactant called, "WellStim" were injected into the well and then forcibly swabbed from the well. 50 barrels of water were initially injected at 1Bbl/min, the next 40 barrels at 2Bbl/min, and the final 30 barrels at 3Bbl/min. Injection pressures were about 200 psi and this pressure bled off within 10 minutes of the injection. A double drum unit or a spudder rig was then used with swab cones to pull fluid and coal fines out of the coal and the well bore. After multiple swabs, made over a day or two as the well filled back with water between swabs, the well was put on rod pump. Coal fines continued to enter the well and plug the pump. After the pump was cleaned, it ran smoothly. This WellStim treatment more than doubled the water production rate to about 35 to 40 barrels per day, however flammable gas was not noted. This well had 5 coal zones perforated that contributed to this flow. However, the well was shutdown in winter and spring of 2005 because of severe flooding of the Wabash River that covered the site with mud and gravel.

In August 2005, the second injection experiment was tested on the Hon #9 well. A 500 barrel water storage tank was brought to the Hon #9 well in early summer of 2005 to re-start the dewatering and store the produced water from the well to do a second injection experiment. A 40 barrel mixture of formation water containing 155 gallons of the WellStim surfactant, supplied by the Nalco Energy Services Company, was pumped into the coals, followed by 440 barrels of coal formation water that was saved from earlier production, at a rate of about 6 barrels per hour and a surface pressure of 200 psi rising to 450 psi. A double drum unit or a spudder rig was then used with swab cones to pull fluid and coal fines out of the coal and the well. After multiple swabs, made over a day or two as the well filled back with water between swabs, the well was put on rod pump. The injection and subsequent pumping from the coals successfully boosted the fluid flow from the coals from 30 barrels per day to about 60 barrels per day. A water line was run from Hon #9 well to the water processing infrastructure in the immediate area oil field for safe and easy disposal of this produced water. The rate declined over the next 14 months down to less than 10 barrels/day when the well was shut down for the last time in October 2006. A total of over 11,000 barrels of water was removed from the coal by this one well.

By mid September 2005, after 30 days of pumping, gas was building in the annular space. It had a pressure of about 12 psi. When flared, the gas produced a 3 to 4 foot high flame that lasted for 10 to 15 seconds. This gas production is the result of local de-pressurization around the immediate bore hole. The gas volume or pressure did not increase during the long dewatering period. Evidently, the well had not lowered a significant volume of coal below the critical pressure. Because the full five-spot pattern had not been completed, water encroachment is likely to have maintained high reservoir pressure.

In October 2005, a pump was placed on the Hon #3 well (**fig. 21b**). Produced water from this well was also piped into the oil field water disposal system. At the same time, the Hon #9 was making about 40 barrels of water a day. Meanwhile, the Hon #3, which had much higher permeability during the pressure build-up/fall-off tests a year earlier and had not been flushed with the surfactant treatment that we tested earlier in the Hon #9, was producing between 70 and 80 barrels of water a day. In the month of October, 2005, the Hon #9 produced a total of 942 barrels of water and the Hon #3 had produced 2139 barrels of water. Low gas pressures were found in the annular space of Hon #3 and Hon #9 by the end of October, probably resulting from the local coal pressure reduction created in the immediate area around the well bore by the pumping.

The Hon #9, which had the surfactant flush injection in August, 2005, produced a total of 942 barrels of water during December 2005 (a daily average of 30 barrels), and a small un-metered amount of gas. The Hon #3 well, which did not have the surfactant injection and which was perforated in only two coals (Herrin and Springfield), continued to produce a high volume of water and maintained a small, but steady, gas pressure, as well. The December 2005 total for the Hon #3 was 2444 barrels of water (a daily average of 79 barrel); gas was un-metered. Earlier pressure transient tests in the Hon #3 well showed one coal with possibly a very high permeability and this coal was likely responsible for the high water flow.

In January 2006 the Hon #3 and #9 wells continued to yield water at about the same rate as the previous month; they were averaging about 78 and 27 barrels of water a day, respectively. The water was being piped into the existing oil field water re-injection system. This steady flow of water indicates we have a good permeability pathway.

Another development in January 2006 was the drilling and casing of the two new dewatering wells planned for our pilot. These are the Hon #10 and the Hon #11, drilled southwest and northwest of the Hon #9. These wells were perforated and hydraulically fracture-stimulated. The last of our dewatering wells needed to complete the five-spot pattern was to be an old plugged well, the Hon #6. This well would have been re-completed to the northeast of the Hon #9, however with the second flooding of our site by the Wabash River in the winter of 2006 and damage to our existing surface equipment, further development was not attempted.

Hon #10 and #11 were each perforated in the Survant and the Davis/Dekoven coals at a rate of four holes per foot. Each well hydraulically fracture stimulated in the same way other than the Hon #10 used size 20-40 mesh sand and the Hon #11 used 10-20 mesh sand. Three frac pump trucks and two sand dump trucks were employed. In each frac job, 250 gallons of 10% HCl were initially pumped into the well to clean out the perforations followed by fresh water at increasing pressure until the formation broke down and the fracture initiated. Fine 100 mesh sand was initially injected, followed by coarser main sand and then an overflush to displace the sand further into the coal.

In Hon #10 well, **(Fig. 23)** following the acid injection, the hydraulic pressure was rapidly increased to about 1900 psi, when the formation broke down and the fracture was initiated. This was followed by approximately 250 barrels of water injected at about 34 barrels/minute, that carried 500 lbs of 100 mesh sand. This was followed by the main injection of 5000 pounds of the main 20/40 mesh frac sand at a rate of 34 barrels/minute and at a pressure of about 1650 psi. After the sand was delivered, water injection continued at the same rate and pressure, extending the fracture and displacing the sand deep into the formation. At the end of the first stage of the frac job and with modest injection continuing, perf balls were dropped into the well to block off the perforations that were taking the most fluid. Then the second stage of the frac began with a repeat of the acid, 100 mesh sand, then the coarser main package of frac sand and water. Breakdown pressure climbed from 1900 psi in Stage 1 to nearly 2200 psi in Stage 2. Injection pressures rose to about 2100 psi then slowly declined to between 1800 and 1900 psi. About 5000 lbs of 20/40 sand were injected in this second stage and the sand was displaced with continued injection. A total of 1884 barrels of water were injected during the two stage frac.

The Hon #11 well frac did not run as smoothly as in the Hon #10.**(Fig. 24)** In the first stage, higher breakdown pressure was required (2200 psi) and water flow rates were less than in Hon #10. A full load of 500 lbs of 100 mesh sand followed by 5000 lbs of 10/20 mesh sand was injected. Just as the flush was beginning, the job was interrupted by a leak in the well head along a weld that required an immediate shut-down. Pressure was reduced to atmospheric level so that the weld could be repaired. No first stage flush could be applied. After several attempts to re-weld the leak in the well head, pressure continuity was finally achieved. Then, the well was re-pressured, perf balls dropped and the second stage was begun. Much higher break-down pressure (2900 psi) was needed to initiate the second stage fracture while water injection rated dropped from a peak of 26 barrels/minute to about 20 barrels/minute. Injection pressure climbed during the 100 mesh injection peaking at about 3150 psi, while the water injection rate remained at 20 to 20 barrels/minute. Pressures declined during the main injection of the 10/20 mesh sand while the water injection rate climbed from a low of about 10 barrels/minute to a steady injection level of about 20 barrels/min. The overflush following the injection of the main sand initially at a rate of 20 barrels/minute, then declined sharply to 13 to 14 barrels/min when one pump was shut down, until the end of the flush displacement. A total of 1546 barrels of fluid were injected into the formation. When this well was swabbed for several cycles after this frac job and considerable sand came back into the well bore and was removed. This demonstrated the value of the overflush after the sand injection.

When the Hon #10 and #11 wells were placed on pump in November 2006, they yielded comparable amounts of water from the Survant and the Davis/Dekoven coal perforated intervals in the 50 to 60 barrels/day range for two months. The Hon #11, which had the significant sand production during the swab runs, ran smoothly. The wells were shut down when the Wabash River flooded the site again in January 2007. They were never repaired and restarted.

CONCLUSIONS

Three new core holes and a multi-well coalbed methane (CBM) pilot project were drilled to gather coal gas data in Illinois. Two wells, the Hon #9 and Wasem C-1 wells, were located in White County and the third (the Ameren #1-24 well) was drilled in the deepest part of the Illinois Coal basin in Jasper County. Multiple coals were cored in order to determine their gas content, adsorption isotherms, gas chemical and isotopic composition, and coal petrography and maturation. From the core data, the well tests, and behavior of the pilot wells, the following conclusions can be made:]

- Locations with 20 or more feet of net coal are common and should be sought for potential prospects. All three of our test areas had greater than 20 feet of coal, though it typically included five or six different seams.
- Gas contents (dmmf) varied by seam and depth from 41 scf/t in the Wise Ridge Coal of the Wasem C-1 well to 19 scf/ton in the Seeleyville Coal of the Ameren 1-24 well. In general, the Hon #9 averaged 94 scf/ton, the Wasem C-1 (excluding the anomalously low Wise Ridge coals) averaged 92 scf/ton, and the Ameren 1-24 well averaged 121 scf/ton. The cored coals, each starting with the Danville Coal, ranged in depth from 756 to 1114 ft in the Hon #9 well, from 387 to 899 ft in the Wasem C-1 well, and from 1188 to 1500 ft in the Ameren well.
- From the desorbed methane ^{13}C and deuterium isotopes, it was clear that the origin of the gas was biogenic. In the deepest well, the Ameren 1-24, there was a shift slightly toward

the thermogenic field, indicating that these coals contained a mix of mostly biogenic methane with small amounts of thermal methane.

- Permeability in the coal was measured in the Hon #9 well through pressure transient analysis of pressure build up and fall-off rates with water injection. Each seam was tested separately. Permeability was regarded as fair, ranging from 3 to 33 mD in the Hon #9 well. A test in the Herrin Coal of the nearby Hon #3 well had only 1 mD permeability as compared to the 4.3 mD value in the Hon #9 well.
- Four-fifths of the planned CBM pilot wells were drilled and completed. Different stimulation techniques were employed to evaluate the cost and effectiveness of these services. The base case in the unstimulated Hon #9 well produced about 12 barrels/day. This well then had a water injection using one barrel of a commercial surfactant, followed by two days of swabbing. This removed considerable coal fines and boosted the water production to about 36 barrels/day. Later, an even larger water injection treatment using 3 barrels of surfactant and 490 barrels of formation water, followed by two days of swabbing. This further doubled the water production rate to 60 barrels/day. The Hon #10 and #11 wells were conventionally hydrofraced, using 5000 pounds of 10/20 mesh sand and 20/40 mesh sand proppant, respectively, following an initial injection of 500 pounds of 100 mesh sand. Subsequent production in each of these wells was the same at nearly 60 barrels of water/day. Thus, a large injection and swab of water with surfactant was the cheapest stimulation technique based on initial water production. How this would compare to a conventional hydro sand frac over time is unknown.

RECOMMENDATIONS

- East-central Illinois is emerging as a prospective area for CBM. Net coals are thick and biogenic processes seem to be well advanced with the westward groundwater flow from the Indiana edge of the coal field. This area, particularly from White to Clark Counties, deserves further evaluation.
- CBM pilots are necessary to evaluate production potential. Patience is required as it may take from a few months to a year to bring the coal to below the critical desorption pressure because Illinois coals desorb slowly and are likely to be undersaturated.
- Since well cost is a major factor in the economics of a CBM project, simple well stimulation using a slug of formation water with a commercial surfactant, may provide just as effective a treatment as an expensive, multi-stage hydrofrac.
- CMB exploration and development should proceed in an orderly manner to make economic decisions. In the initial single core data well, coal thickness, gas content, coal isotherms and coal permeability data should be acquired. Leasing may be local and expand if well data is favorable, or a large block can be leased, presumably at a lower rate per acre, and be evaluated with test well. If the data from the first well are favorable, then proceed with multi-well pilot project to determine the ability to dewater the coal and the gas production potential. If this meets economic hurdles, then proceed to develop the property with successive well patterns. One operator in Illinois is locating development wells on a 50 to 60 acre spacing in a diamond-shaped pattern to reflect hypothetical differences between face and butt cleat permeabilities.

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Table 1. Coal and shale samples obtained from three ISGS test wells for gas and other analyses

County/ location	Well Name	Coal or shale/ sample no.	Sample depth (ft)	Seam or bed thickness(ft)	Sample bulk density(g/cm^3)	Sample volume (cm^3)	Sample weight (g)
White/Sec.9,	Hon #9	Danville/1	756.2	3.7	1.31	1350	1774
T4S, R14W	Hon #9	Danville/2	759.7		1.48	1340	1978
	Hon #9	Herrin/1	803.5	5.3	1.37	1300	1779
	Hon #9	Herrin/2	805.0		1.34	1230	1645
	Hon #9	Herrin/3	807.0		1.36	1390	1895
	Hon #9	Turner Mine Sh.	874.0	7.3	2.06	950	1958
	Hon #9	Springfield/1	880.8	4.4	1.33	1375	1835
	Hon #9	Springfield/2	882.7		1.29	1340	1734
	Hon #9	Springfield/3	883.7		1.37	1090	1494
	Hon #9	Excello Sh.	967.4	7.1	2.11	1170	2464
	Hon #9	Houchin Creek	968.7	2.6	1.35	1400	1884
	Hon #9	Survant/1	993.9	3.7	1.37	1310	1789
	Hon #9	Survant/2	994.7		1.27	1290	1640
	Hon #9	Survant/3	996.4		1.33	1290	1717
	Hon #9	Mecca Quary Sh.	1058.0	4.3	2.44	1350	3294
	Hon #9	Dekoven	1062.5	2.3	1.43	1245	1782
	Hon #9	Davis/1	1107.5	6.9	1.45	1375	1997
	Hon #9	Davis/2	1111.3		1.34	1335	1785
	Hon #9	Davis/3	1113.7		1.38	1350	1866
White/Sec.24,	Wasem#C1	Danville/1	386.7	2.4	1.35	1375	1861
T7S, R10E	Wasem#C1	Danville/2	387.7		1.38	1380	1903
	Wasem#C1	Herrin/1	450.0	7.2	1.29	1460	1881
	Wasem#C1	Herrin/2	451.0		1.30	1400	1821
	Wasem#C1	Herrin/3	453.8		1.36	1375	1869
	Wasem#C1	Springfield/1	532.1	5.1	1.34	1350	1805
	Wasem#C1	Springfield/2	533.1		1.31	1450	1897
	Wasem#C1	Springfield/3	535.0		1.36	1350	1831
	Wasem#C1	Excello Shale	601.0	2.3	1.95	1310	2558
	Wasem#C1	Houchin Creek	603.6	2.9	1.31	1220	1598
	Wasem#C1	Survant	644.0	1.7	1.35	1300	1761
	Wasem#C1	Mecca Quary Sh.	696.5	2.9	2.23	1310	2920
	Wasem#C1	Davis/1	808.0	6.0	1.39	1325	1844
	Wasem#C1	Davis/2	816.8		1.37	1300	1777
	Wasem#C1	Davis/3	818.3		1.31	1300	1702
	Wasem#C1	Mt. Rorah/1	887.3	2.5	1.41	1375	1943
	Wasem#C1	Mt. Rorah/2	899.2		1.45	1440	2090
Jasper/Sec.24,	Ameren#1-24	Danville/1	1188.0	3.2	1.42	1250	1771
T6N, R8E	Ameren#1-24	Danville/2	1189.0		1.40	1300	1815
	Ameren#1-24	Jamestown/1	1215.7	2.9	1.43	1450	2069
	Ameren#1-24	Jamestown/2	1216.8		1.55	1400	2171
	Ameren#1-24	Anna Shale	1225.9		2.33	1350	3152
	Ameren#1-24	Herrin/1	1229.7	6.1	1.46	1350	1970
	Ameren#1-24	Herrin/2	1227.3		1.33	1250	1666
	Ameren#1-24	Herrin/3	1230.9		1.44	1400	2012
	Ameren#1-24	Briar Hill	1258.7	3.0	1.38	1480	2037
	Ameren#1-24	Shale X	1261.8		2.67	1320	3520
	Ameren#1-24	Springfield	1269.4	2.0	1.56	1325	2062
	Ameren#1-24	Excello Shale	1347.3	6.0	2.00	1480	2960
	Ameren#1-24	Houchin Creek	1349.0	2.0	1.57	1450	2278
	Ameren#1-24	Survant	1423.6	2.0	1.34	1275	1714
	Ameren#1-24	Shale Y	1484.9		2.06	1450	2981
	Ameren#1-24	Upper Dekoven	1486.3	3.0	1.35	1350	1820
	Ameren#1-24	Lower Dekoven	1491.2	1.0	1.83	910	1668
	Ameren#1-24	Seelyville/1	1497.0	7.0	1.38	1450	1995
	Ameren#1-24	Seelyville/2	1498.1		1.50	1400	2103
	Ameren#1-24	Seelyville/3	1500.3		1.40	1300	1825

Table 2. Gas contents of coal and shale samples obtained from three ISGS test wells.

County	Well name	Coal or shale/ sample no.	As-received total gas content (scf/t)	Dry, mineral matter free gas content (scf/t)			
				Lost	Desorbed	Residual	Total
White	Hon #9	Danville/1	73.8	2.3	75.3	18.4	96.0
	Hon #9	Danville/2	62.2	4.0	89.3	5.7	99.0
	Hon #9	Herrin/1	64.4	2.1	72.3	14.2	88.6
	Hon #9	Herrin/2	75.7	3.3	75.2	14.0	92.5
	Hon #9	Herrin/3	66.3	2.0	69.4	14.6	86.0
	Hon #9	Turner Mine Shale	21.7	0.3	80.7	16.2	97.2
	Hon #9	Springfield/1	61.6	1.1	56.4	20.9	78.4
	Hon #9	Springfield/2	70.0	1.9	69.0	15.2	86.1
	Hon #9	Springfield/3	66.1	2.5	65.6	15.1	83.2
	Hon #9	Excello Sh.	21.8	2.5	117.3	6.6	126.4
	Hon #9	Houchin Creek	66.2	0.6	58.4	29.8	88.8
	Hon #9	Survant/1	75.3	1.4	73.7	20.7	95.8
	Hon #9	Survant/2	72.6	1.0	75.9	15.8	92.7
	Hon #9	Survant/3	71.0	1.1	74.4	11.8	87.3
	Hon #9	Mecca Quary Shale	8.6	0.0	65.9	79.1	145.0
	Hon #9	Dekoven	62.2	1.1	73.3	22.0	96.4
	Hon #9	Davis/1	83.7	3.6	101.7	23.2	128.5
	Hon #9	Davis/2	89.5	3.8	89.8	19.0	112.6
	Hon #9	Davis/3	68.4	1.8	70.0	16.9	88.7
White	Wasem#C1	Danville/1	87.2	2.5	96.3	13.4	112.2
	Wasem#C1	Danville/2	77.8	2.3	88.2	12.4	102.9
	Wasem#C1	Herrin/1	84.9	1.3	81.0	18.7	101.0
	Wasem#C1	Herrin/2	87.7	1.5	91.4	14.3	107.2
	Wasem#C1	Herrin/3	85.2	1.5	95.9	13.5	110.9
	Wasem#C1	Springfield/1	62.3	1.6	72.9	7.9	82.4
	Wasem#C1	Springfield/2	67.5	2.0	72.3	6.1	80.4
	Wasem#C1	Springfield/3	66.3	1.3	74.2	8.0	83.5
	Wasem#C1	Excello Shale	28.2	2.9	122.5	4.9	130.3
	Wasem#C1	Houchin Creek	67.2	1.6	59.5	19.4	80.5
	Wasem#C1	Survant	74.4	4.1	81.2	9.6	94.9
	Wasem#C1	Mecca Quary Shale	12.8	0.0	96.5	7.7	104.2
	Wasem#C1	Davis/1	58.8	1.5	59.8	14.2	75.5
	Wasem#C1	Davis/2	71.4	2.7	72.4	8.6	83.7
	Wasem#C1	Davis/3	67.7	2.8	71.1	7.6	81.5
	Wasem#C1	Mt. Rorah/1	30.8	0.3	31.9	8.8	41.0
	Wasem#C1	Mt. Rorah/2	31.6	0.6	32.9	8.4	41.9
Jasper	Ameren#1-24	Danville/1	75.3	2.3	77.2	20.1	99.6
	Ameren#1-24	Danville/2	78.7	3.3	78.9	22.0	104.2
	Ameren#1-24	Jamestown/1	86.3	3.0	97.5	21.2	121.7
	Ameren#1-24	Jamestown/2	79.4	4.5	112.3	15.7	132.5
	Ameren#1-24	Anna Shale	15.6	2.6	97.7	38.1	138.4
	Ameren#1-24	Herrin/1	84.7	3.7	102.3	15.7	121.7
	Ameren#1-24	Herrin/2	95.0	3.3	86.3	23.4	113.0
	Ameren#1-24	Herrin/3	79.6	2.8	83.1	17.3	103.2
	Ameren#1-24	Briar Hill	73.7	2.4	62.3	32.0	96.7
	Ameren#1-24	Shale X	4.4	0.0	138.0	0.0	138.0
	Ameren#1-24	Springfield	66.4	11.8	120.1	15.6	147.5
	Ameren#1-24	Excello Shale	26.2	0.3	76.9	32.8	110.0
	Ameren#1-24	Houchin Creek	58.2	3.9	75.1	25.7	104.7
	Ameren#1-24	Survant	103.9	3.6	104.9	19.5	128.0
	Ameren#1-24	Shale Y	37.2	5.4	129.8	28.6	163.8
	Ameren#1-24	Upper Dekoven	86.1	7.0	89.7	22.1	118.8
	Ameren#1-24	Lower Dekoven	44.6	5.1	87.5	20.3	112.9
	Ameren#1-24	Seelyville/1	104.7	7.5	103.3	23.6	134.4
	Ameren#1-24	Seelyville/2	103.2	8.4	105.6	25.1	139.1
	Ameren#1-24	Seelyville/3	127.0	10.5	120.9	28.0	159.4

Table 3. Vitrinite reflectance and petrographic composition of coal samples obtained from the three ISGS test wells.

County	Well name	Coal/ sample no.	Vitrinite reflectance ($\%R_m$)	Petrographic composition (%volume)				
				Vitrinite macerals		Liptinite macerals	Inertinite macerals	Mineral matter
				Total	Desmocollinite			
White	Hon #9	Danville/1	0.55	81.8	9.4	4.2	8.2	5.8
	Hon #9	Danville/2	0.55	74.0	4.0	4.0	3.8	18.2
	Hon #9	Herrin/1	0.59	84.2	7.6	3.4	6.4	6.0
	Hon #9	Herrin/2	0.57	89.4	8.0	3.0	6.8	0.8
	Hon #9	Herrin/3	0.60	87.0	11.0	1.8	5.6	5.6
	Hon #9	Springfield/1	0.58	84.8	9.6	3.6	8.4	3.2
	Hon #9	Springfield/2	0.58	86.0	11.4	4.4	9.2	0.4
	Hon #9	Springfield/3	0.61	76.8	12.0	4.0	18.4	0.8
	Hon #9	Houchin Creek	0.53	86.2	13.6	4.6	2.8	6.4
	Hon #9	Survant/1	0.57	75.0	13.4	8.4	9.4	7.2
	Hon #9	Survant/2	0.56	77.6	16.4	4.0	14.0	4.4
	Hon #9	Survant/3	0.57	67.0	15.8	14.0	15.6	3.4
	Hon #9	Dekoven	0.55	77.0	8.4	3.8	5.2	14.0
	Hon #9	Davis/1	0.58	76.0	15.0	6.6	10.0	7.4
	Hon #9	Davis/2	0.56	75.8	8.2	4.0	9.6	10.6
	Hon #9	Davis/3	0.56	80.8	22.0	4.4	6.8	8.0
White	Wasem #C1	Danville/1	0.59	84.2	5.8	6.4	6.4	3.0
	Wasem #C1	Danville/2	0.60	79.8	10.4	5.0	6.2	9.0
	Wasem #C1	Herrin/1	0.61	91.6	13.2	3.8	2.8	1.8
	Wasem #C1	Herrin/2	0.60	77.4	14.0	5.0	17.2	0.4
	Wasem #C1	Herrin/3	0.60	89.2	12.0	2.8	6.2	1.8
	Wasem #C1	Springfield/1	0.60	79.0	12.4	6.6	11.0	3.4
	Wasem #C1	Springfield/2	0.60	72.8	18.6	9.2	15.4	2.6
	Wasem #C1	Springfield/3	0.58	81.8	12.0	6.4	8.6	3.2
	Wasem #C1	Houchin Creek	0.60	90.4	8.6	3.0	5.8	0.8
	Wasem #C1	Survant	0.58	78.8	16.8	7.0	11.2	3.0
	Wasem #C1	Davis/1	0.60	77.6	9.2	9.8	6.0	6.6
	Wasem #C1	Davis/2	0.62	88.0	14.4	3.6	7.0	1.4
	Wasem #C1	Davis/3	0.63	81.4	9.6	6.2	11.8	0.6
	Wasem #C1	Mt. Rorah/1	0.63	82.0	7.8	8.0	1.4	8.6
	Wasem #C1	Mt. Rorah/2	0.64	78.4	15.2	7.6	8.2	5.8
Jasper	Ameren #1-24	Danville/1	0.60	86.4	9.8	2.4	4.0	7.2
	Ameren #1-24	Danville/2	0.61	80.0	5.2	6.0	10.0	4.0
	Ameren #1-24	Jamestown/1	0.58	68.8	14.0	7.2	12.0	12.0
	Ameren #1-24	Jamestown/2	0.60	70.8	10.0	2.0	19.2	8.0
	Ameren #1-24	Herrin/1	0.61	85.4	9.0	3.6	7.4	3.6
	Ameren #1-24	Herrin/2	0.62	74.0	4.8	3.2	11.6	11.6
	Ameren #1-24	Herrin/3	0.60	82.4	13.6	4.0	11.2	2.4
	Ameren #1-24	Briar Hill	0.60	86.6	14.2	5.6	5.4	2.4
	Ameren #1-24	Springfield	0.58	78.0	8.0	4.0	11.2	6.8
	Ameren #1-24	Houchin Creek	0.60	77.2	8.0	4.8	3.2	14.8
	Ameren #1-24	Survant	0.65	84.0	13.6	7.4	7.6	1.0
	Ameren #1-24	Upper Dekoven	0.61	90.0	16.6	3.6	4.8	1.6
	Ameren #1-24	Lower Dekoven	0.60	60.2	9.8	2.6	4.8	32.4
	Ameren #1-24	Seelyville/1	0.61	78.0	16.0	6.4	8.4	7.2
	Ameren #1-24	Seelyville/2	0.62	65.0	12.4	7.2	10.2	17.6
	Ameren #1-24	Seelyville/3	0.60	84.0	11.2	6.4	5.2	4.4

Table 4. Chemical and isotopic composition of gas from individual samples of coal seams and shale beds from three ISGS test wells.
(Most values are averages of multiple measurements.)

County	Well name	Coal or shale	Sample depth (ft)	Desorbed Gas chemical composition (vol %, air-free-basis)					Gas dryness index (C_1/C_{1-5})	CH_4 isotopic composition (‰)	
				N_2	CO_2	CH_4	C_{2+}	CH_4+C_{2+}		$\delta^{13}C_{PDB}$	δD_{SMOW}
White	Hon #9	Danville	758.0	24.35	1.24	74.40	0.00	74.4	1.00	-69.91	-214.1
		Herrin	805.2	28.87	1.94	68.30	0.89	69.2	0.99	-70.06	-217.0
		Springfield	882.4	31.03	1.40	66.10	1.46	67.6	0.98	-66.83	-210.9
		Houchin Creek	968.7	28.36	1.72	68.61	1.31	69.9	0.98	-65.68	-216.0
		Survant	995.1	26.58	1.85	70.44	1.13	71.6	0.98	-66.95	-220.3
		Dekoven	1062.5	30.40	1.47	67.92	0.21	68.1	1.00	-65.04	-209.3
		Davis	1110.8	24.97	1.37	73.32	0.34	73.7	1.00	-65.11	-205.5
		Turner Mine Shale	874.0	51.11	0.18	47.67	1.04	48.7	0.98	-66.26	-211.1
		Excello Shale	967.4	54.55	0.32	44.03	1.10	45.1	0.98	-66.68	-215.8
White	Wasem#C-1	Danville	387.2	8.38	2.61	88.68	0.33	89.0	1.00	-67.93	-222.6
		Herrin	451.6	11.67	2.41	85.77	0.16	85.9	1.00	-68.95	-219.1
		Springfield	533.4	13.42	1.79	83.39	1.39	84.8	0.98	-69.80	-216.2
		Houchin Creek	603.6	27.95	1.32	70.24	0.49	70.7	0.99	-70.63	-209.2
		Survant	644.0	16.39	1.32	82.26	0.03	82.3	1.00	-71.17	-206.1
		Davis	814.4	22.41	1.91	75.68	0.00	75.7	1.00	-72.25	-210.0
		Mt. Rorah	893.3	41.92	1.36	55.55	1.17	56.7	0.98	-70.87	-198.7
		Excello Shale	601.0	30.36	0.50	68.41	0.73	69.1	0.99	-69.74	-206.4
		Mecca Q. Shale	696.5	51.41	0.63	47.89	0.07	48.0	1.00	-75.05	-209.7
Jasper	Ameren#1-24	Danville	1188.5	28.68	1.83	68.59	0.90	69.5	0.99	-67.70	-212.1
		Jamestown	1216.3	14.31	2.98	81.69	1.03	82.7	0.99	-65.95	-211.9
		Herrin	1229.3	18.62	2.72	77.98	0.68	78.7	0.99	-66.99	-213.9
		Briar Hill	1258.7	20.20	2.34	76.19	1.28	77.5	0.98	-66.55	-212.0
		Springfield	1269.4	14.87	1.86	81.90	1.37	83.3	0.98	-64.39	-213.2
		Houchin Creek	1349.0	20.35	1.34	76.48	1.83	78.3	0.98	-65.86	-211.6
		Survant	1423.6	12.98	1.52	84.81	0.69	85.5	0.99	-65.85	-212.3
		Upper Dekoven	1486.3	11.94	3.04	83.35	1.67	85.0	0.98	-60.90	-209.0
		Lower Dekoven	1491.2	40.97	1.96	56.14	0.92	57.1	0.98	-61.48	-213.5
		Seelyville	1498.5	11.33	2.69	85.46	0.52	86.0	0.99	-59.99	-211.3
		Anna Shale	1225.9	54.67	1.27	43.57	0.49	44.1	0.99	-67.70	-213.6
		Shale X	1261.8	63.22	2.58	33.36	0.84	34.2	0.98	-65.66	-218.2
		Excello Shale	1347.9	43.01	0.25	55.19	1.55	56.7	0.97	-67.40	-211.6
		Shale Y	1484.9	28.15	1.27	69.19	1.40	70.6	0.98	-61.97	-210.6

Table 5. Gas saturation and related data from methane adsorption isotherms of coal samples from three ISGS test wells.

County/ Well name	Coal (or shale)/ Sample no.	Depth (ft)	Estimated geothermal gradient (°F /100 ft)	Mean annual surface temperature (°F)	Calculated reservoir temperature (°F)	Calculated hydrostatic pressure (psi)	Coal gas content (scf/t) dmmf	Coal gas content (scf/t) daf	Langmuir parameters P_L (psia)	Langmuir parameters V_L (scf/t, daf)	Gas storage capacity at reservoir pressure (scf/t, daf)	Gas saturation at reservoir Pressure (%)
White/	Danville/1	756.2	1.7	56	69	327.4	96.0	92.0	865.5	574.0	157.6	58.4
Hon #9	Danville/2	759.7	1.7	56	69	329.0	99.0	93.8	740.9	474.4	145.9	64.3
	Herrin/1	803.5	1.7	56	70	347.9	88.6	84.1	779.8	513.0	158.3	53.1
	Herrin/2	805.0	1.7	56	70	348.6	92.5	90.6	786.4	523.8	160.9	56.3
	Herrin/3	807.0	1.7	56	70	349.4	86.0	83.4	781.8	517.3	159.8	52.2
	Springfield/1	880.8	1.7	56	71	381.4	78.4	76.0	764.1	525.8	175.1	43.4
	Springfield/2	882.7	1.7	56	71	382.2	86.1	84.3	795.6	508.0	164.9	51.1
	Springfield/3	883.7	1.7	56	71	382.6	83.2	81.4	739.6	520.6	177.5	45.9
	Houchin Creek	968.7	1.7	56	72	419.4	88.8	66.2	583.2	376.1	157.3	42.1
	Survant/1	993.9	1.7	56	73	430.4	95.8	91.5	526.8	397.5	178.7	51.2
	Survant/2	994.7	1.7	56	73	430.7	92.7	89.4	621.2	418.1	171.2	52.2
	Survant/3	996.4	1.7	56	73	431.4	87.3	85.1	594.0	383.7	161.4	52.7
	Dekoven	1062.5	1.7	56	74	460.1	96.4	91.4	507.0	402.6	191.5	47.7
	Davis/1	1107.5	1.7	56	75	479.5	128.5	115.0	486.7	429.8	213.3	53.9
	Davis/2	1111.3	1.7	56	75	481.2	112.6	108.0	496.7	484.8	238.6	45.3
	Davis/3	1113.7	1.7	56	75	482.2	88.7	83.7	518.6	395.7	190.7	43.9
	Turner Mine Sh	874.0	1.7	56	71	378.4	97.2	75.0	871.7	617.4	186.9	40.1
	Excello Shale	967.4	1.7	56	72	418.9	126.4	89.2	887.3	553.9	177.6	50.2
	Mecca Quary Sh	1058.0	1.7	56	74	458.1	145.0	57.9	637.4	187.4	78.4	73.9
White/	Danville/1	386.7	1.7	56	63	167.4	112.2	108.5	478.7	480.4	124.5	87.2
Wasem#C-1	Danville/2	387.7	1.7	56	63	167.9	102.9	97.5	440.6	494.5	136.4	71.5
	Herrin/1	450.0	1.7	56	64	194.9	101.0	98.6	482.5	478.1	137.5	71.7
	Herrin/2	451.0	1.7	56	64	195.3	107.2	104.2	446.3	473.9	144.2	72.2
	Herrin/3	453.8	1.7	56	64	196.5	110.9	105.5	441.3	470.5	145.0	72.8
	Springfield/1	532.1	1.7	56	65	230.4	82.4	79.2	414.4	532.8	190.4	41.6
	Springfield/2	533.1	1.7	56	65	230.8	80.4	78.7	450.3	530.2	179.7	43.8
	Springfield/3	535.0	1.7	56	65	231.7	83.5	80.3	425.2	585.2	206.4	38.9
	Houchin Creek	603.6	1.7	56	66	261.4	80.5	78.7	459.4	491.9	178.4	44.1
	Survant	644.0	1.7	56	67	278.9	94.9	90.4	461.2	535.0	201.6	44.8
	Davis/1	808.0	1.7	56	70	349.9	75.5	71.5	482.6	544.3	228.8	31.3
	Davis/2	816.8	1.7	56	70	353.7	83.7	81.9	483.3	543.1	229.5	35.7
	Davis/3	818.3	1.7	56	70	354.3	81.5	79.8	491.2	531.7	222.8	35.8
	Mt. Rorah/1	887.3	1.7	56	71	384.2	41.0	38.9	381.6	529.2	265.5	14.7
	Mt. Rorah/2	899.2	1.7	56	71	389.4	41.9	39.2	399.0	510.4	252.1	15.6
	Excello Sh	601.0	1.7	56	66	260.2	130.3	99.1	513.9	532.0	178.8	55.4
	Mecca Quary Sh	696.5	1.7	56	68	301.6	104.2	63.5	376.1	533.1	237.2	26.8
Jasper/	Danville/1	1188.0	1.9	55	78	514.4	95.8	99.6	610.8	468.2	214.0	46.5
Ameren#1-24	Danville/2	1189.0	1.9	55	78	514.8	100.4	104.2	579.5	446.2	209.9	49.6
	Jamestown/1	1215.7	1.9	55	78	526.4	115.3	121.7	587.5	456.2	215.6	56.5
	Jamestown/2	1216.8	1.9	55	78	526.9	123.1	132.5	570.2	441.1	211.8	62.5
	Herrin/1	1229.7	1.9	55	78	532.5	117.1	121.7	513.6	444.9	226.5	53.7
	Herrin/2	1227.3	1.9	55	78	531.4	110.6	113.0	492.8	439.7	228.1	49.5
	Herrin/3	1230.9	1.9	55	78	533.0	98.6	103.2	538.9	447.3	222.4	46.4
	Briar Hill	1258.7	1.9	55	79	545.0	92.9	96.7	561.6	411.4	202.6	47.7
	Springfield	1269.4	1.9	55	79	549.7	132.0	147.5	551.1	460.8	230.1	64.1
	Houchin Creek	1349.0	1.9	55	81	584.1	87.8	104.7	634.9	359.6	172.3	60.8
	Survant	1423.6	1.9	55	82	616.4	126.3	128.0	540.3	496.0	264.3	48.4
	Upper Dekoven	1486.3	1.9	55	83	643.5	118.8	118.8	563.2	436.1	232.6	51.1
	Lower Dekoven	1491.2	1.9	55	83	645.7	96.6	112.9	606.3	441.0	227.4	49.6
	Seelyville/1	1497.0	1.9	55	83	648.2	128.6	134.4	542.8	478.1	260.2	51.7
	Seelyville/2	1498.1	1.9	55	83	648.7	131.3	139.1	498.1	419.5	237.3	58.6
	Seelyville/3	1500.3	1.9	55	84	649.6	152.0	159.4	509.6	458.0	256.7	62.1
	Anna Shale	1225.9	1.9	55	78	530.8	83.6	138.4	nd	nd	nd	nd
	Shale X	1261.8	1.9	55	79	546.4	36.3	138.0	nd	nd	nd	nd
	Excello Shale	1347.3	1.9	55	81	583.4	86.7	110.0	nd	nd	nd	Nd
	Shale Y	1484.9	1.9	55	83	643	125.2	163.8	nd	nd	nd	Nd

Table 6. Pressure Transient Analysis Results, Hon #9 and Hon #3

Test Name	Perforated Interval (ft)	Net Pay (ft)	Permeability (mD)	Transmissivity (mD·ft/cp)	Skin Factor (Dimensionless)	Average Pressure (psi)
Hon #9						
Test 1	1109-16	5	14.1	71.9	-0.3	496
Test 2	1066-68	2	5.2	10.6	-3.4	516
Test 3	996-1000	4	3.3	13.1	-5.0	440
Test 4	882-886	4	21.7	83.0	-1.8	681
Test 5	805-810	5	4.3	20.4	-4.9	510
Test 6	759-761	2	33.7	63.0	NA	328
Hon #3						
Test 2R	812-16	4	0.99	3.7	-5.1	405

FIGURES

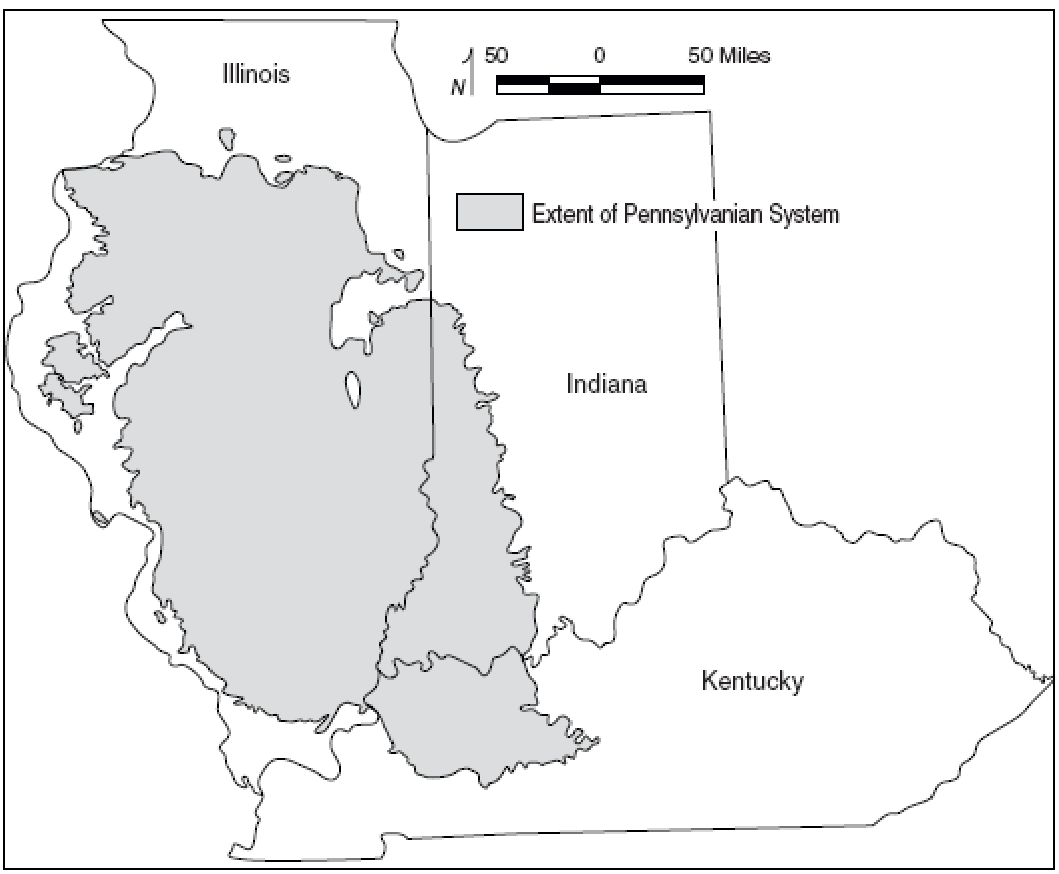


Figure 1. Extent of coal bearing Pennsylvanian strata in the Illinois Basin.

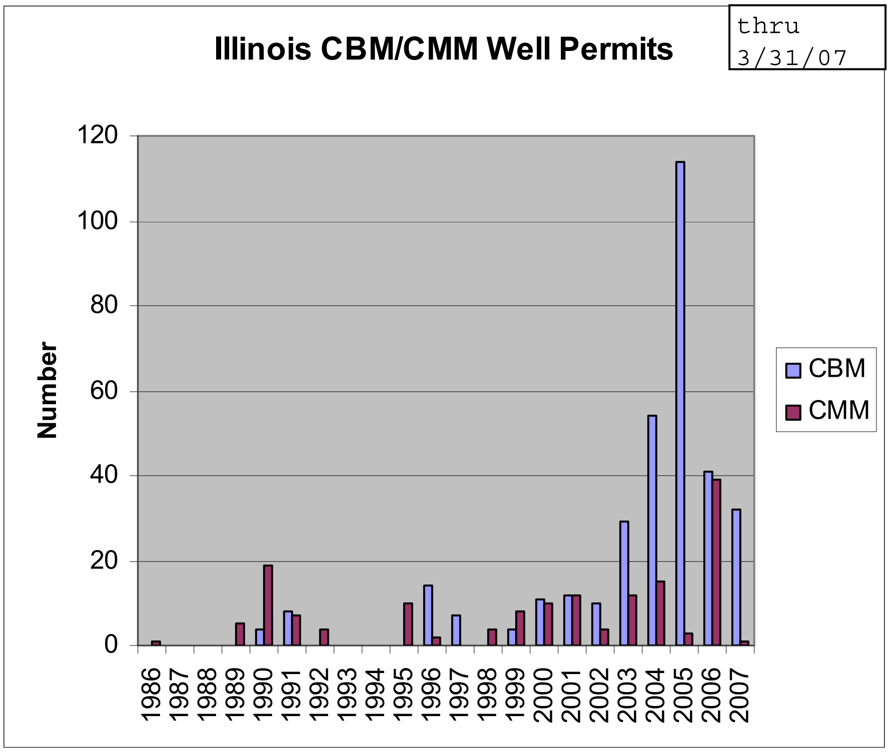


Figure 2a. Drilling permits for Illinios CBM and CMM wells given each year since 1986.

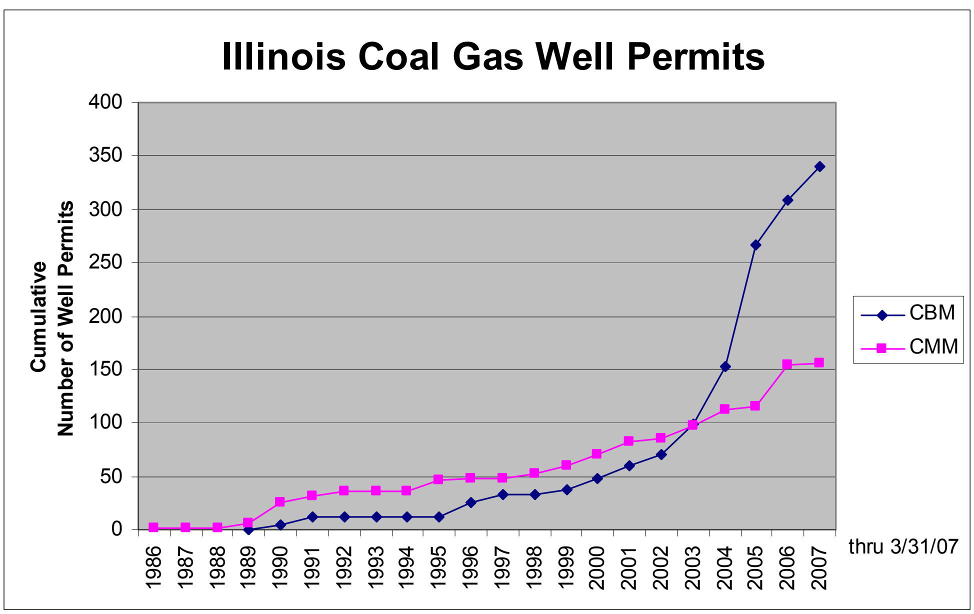


Figure 2b. Cumulative drilling permits for CBM and CMM wells in Illinois since 1986.

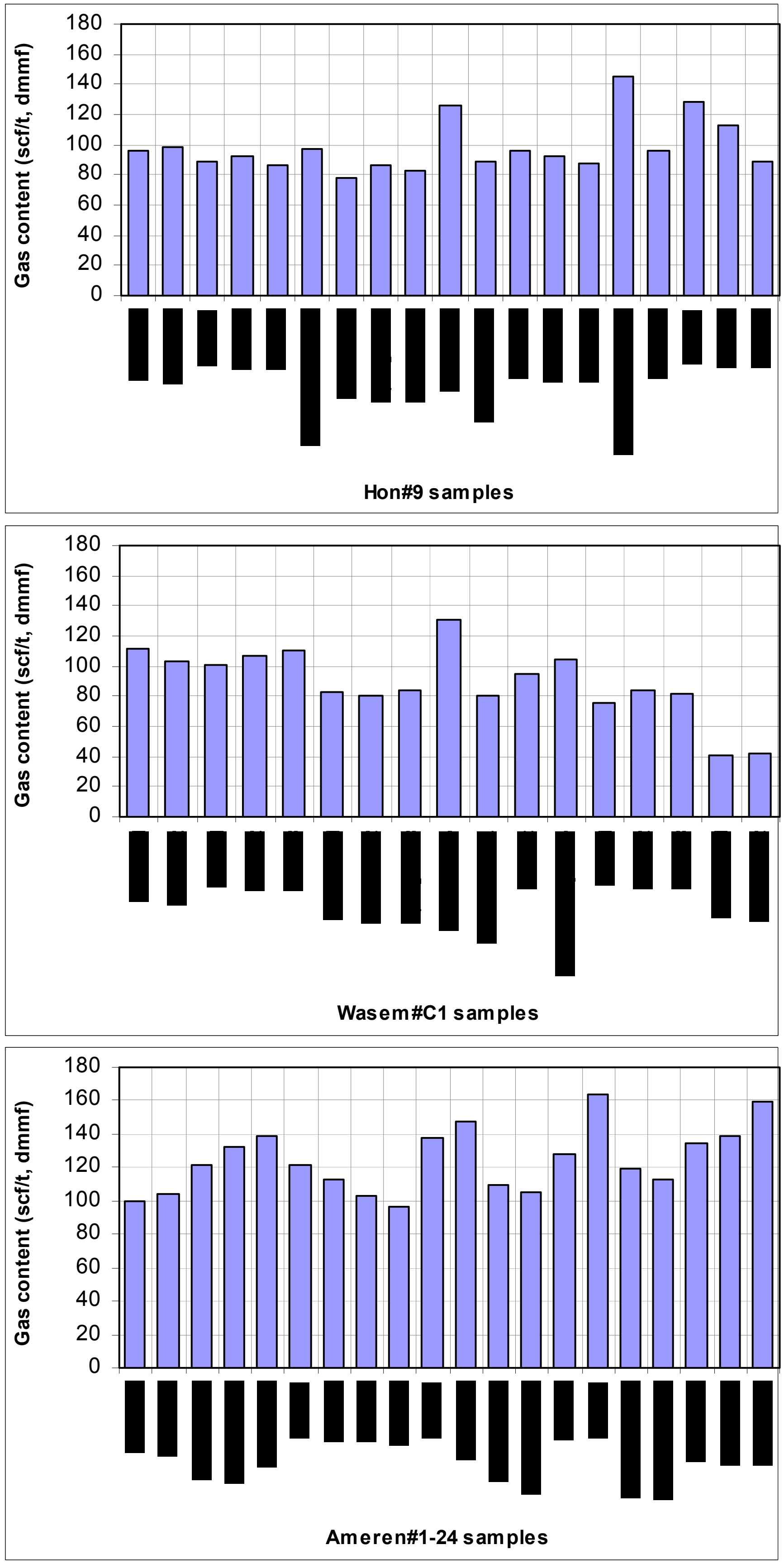


Figure 3. Gas contents of coal and shale samples from three ISGS test wells. Depth increases to right.

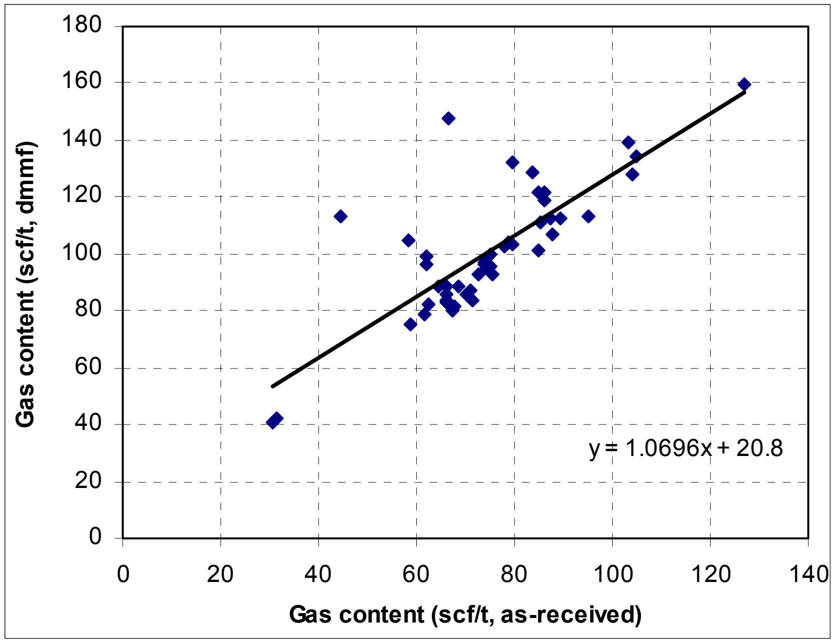


Figure 4. Relationship between gas contents on as-received and dmmf basis for coal samples from two wells from White County and one well from Jasper County.

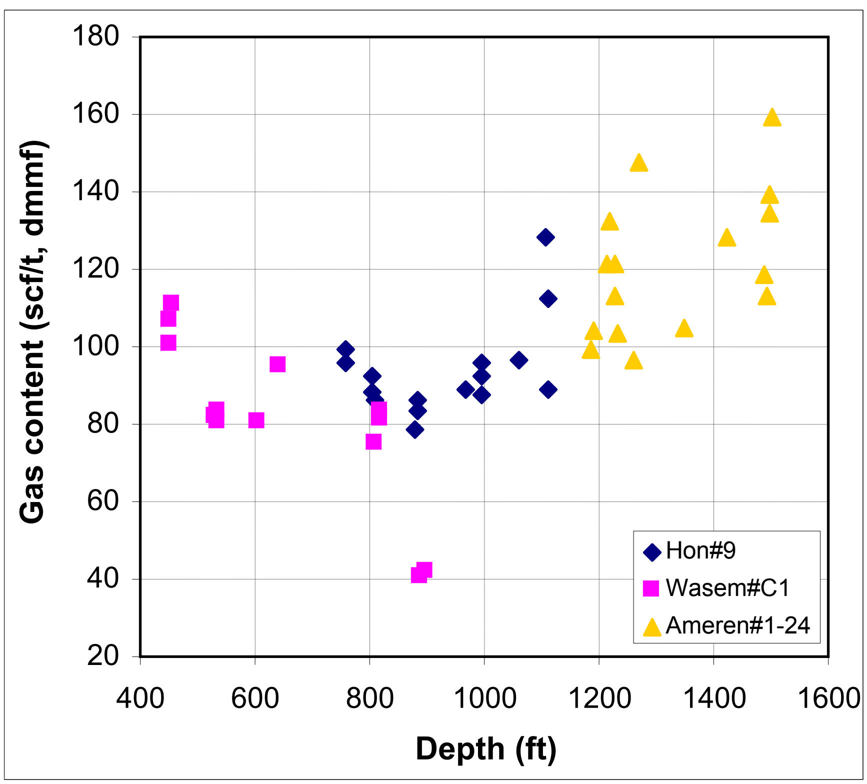


Figure 5. Variation of gas content with depth for multiple coal seams in individual wells.

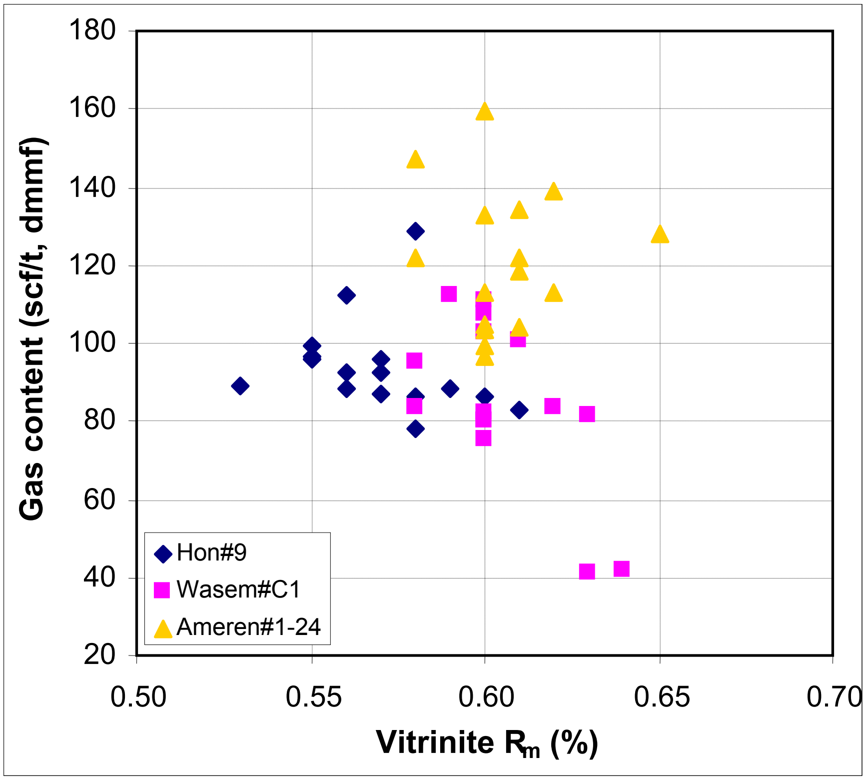


Figure 6. Variation of gas content with vitrinite reflectance for multiple coal seams in individual wells.

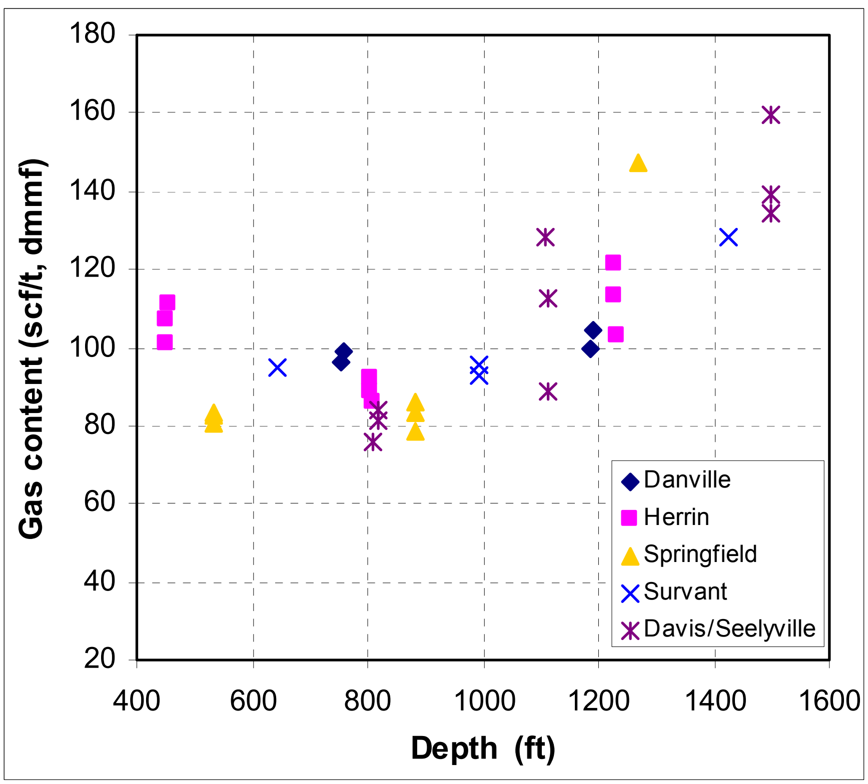


Figure 7. Variation of gas content with depth for individual coal seam in three wells.

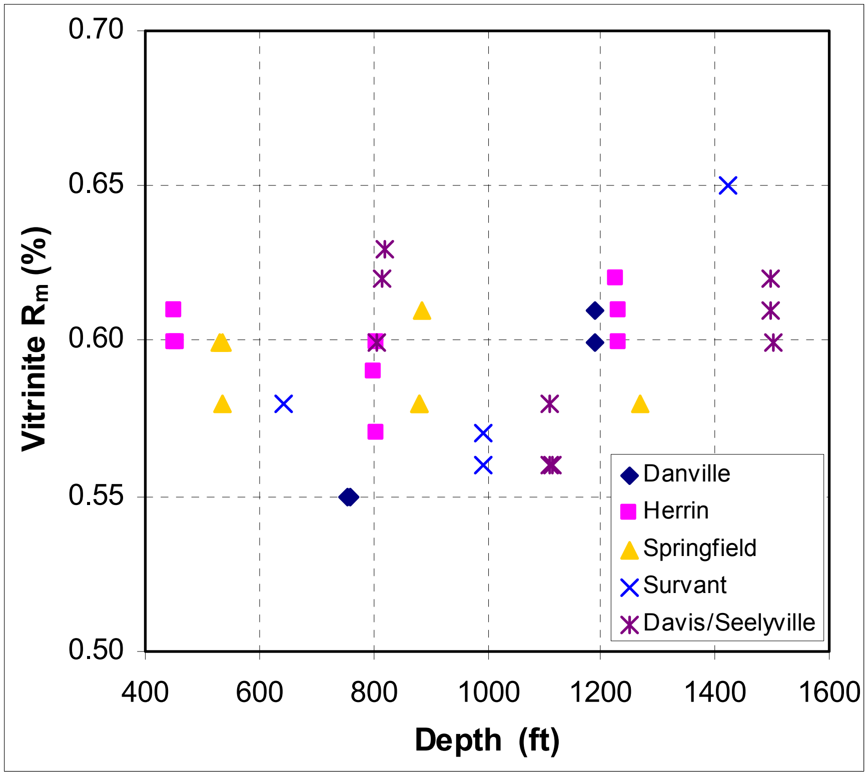


Figure 8. Variation of vitrinite reflectance with depth for individual coal seams in three wells.

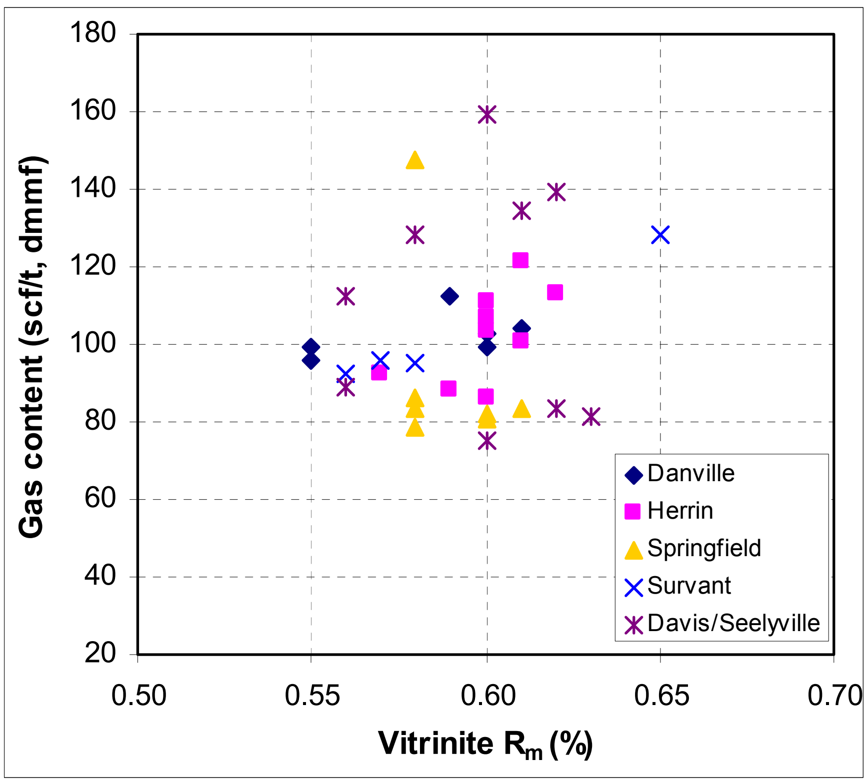


Figure 9. Variation of gas content with vitrinite reflectance for individual coal seams in three wells.

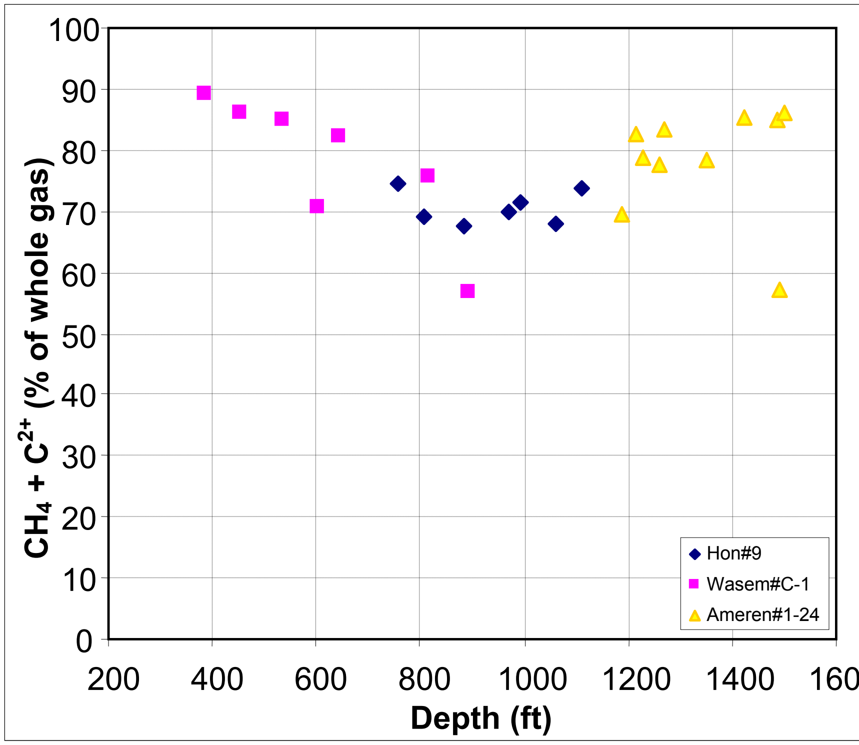


Figure 10. Combustible gas content of coal seams as a function of depth for individual wells. Most values are averages of multiple measurements.

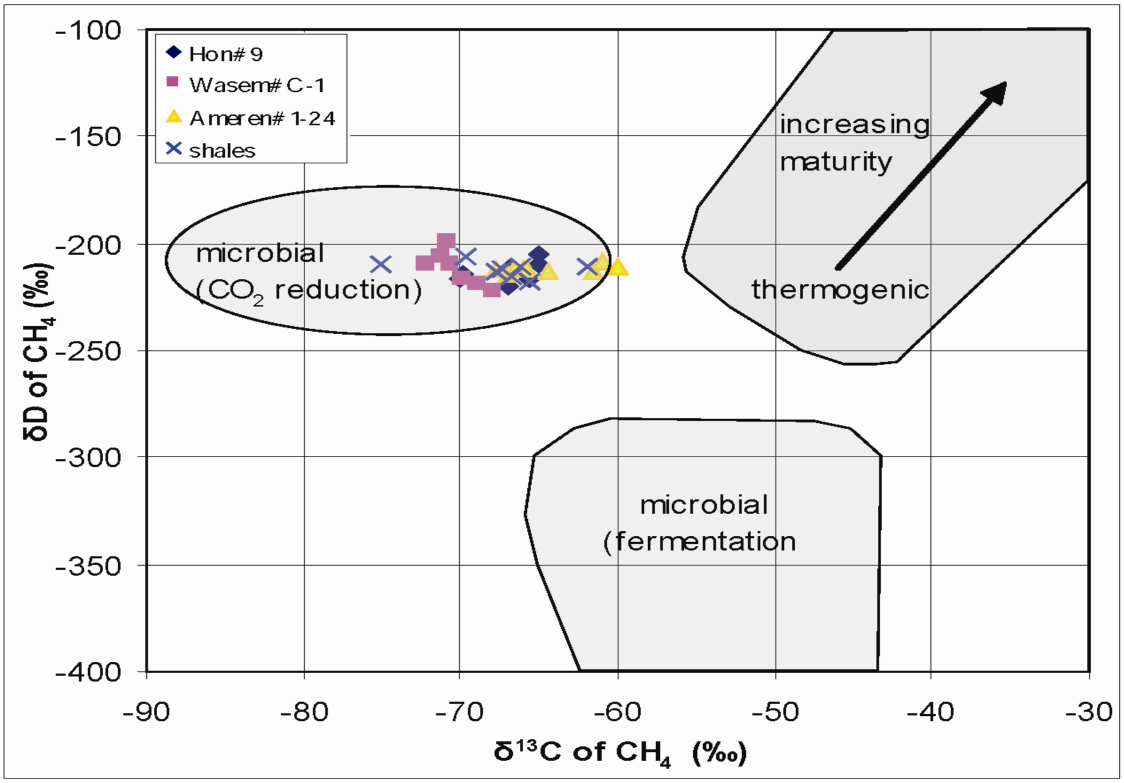


Figure 11. Carbon and hydrogen isotopic compositions of methane fraction of coal and shale gases for three individual wells indicate primarily a microbial or biogenic origin for the methane.

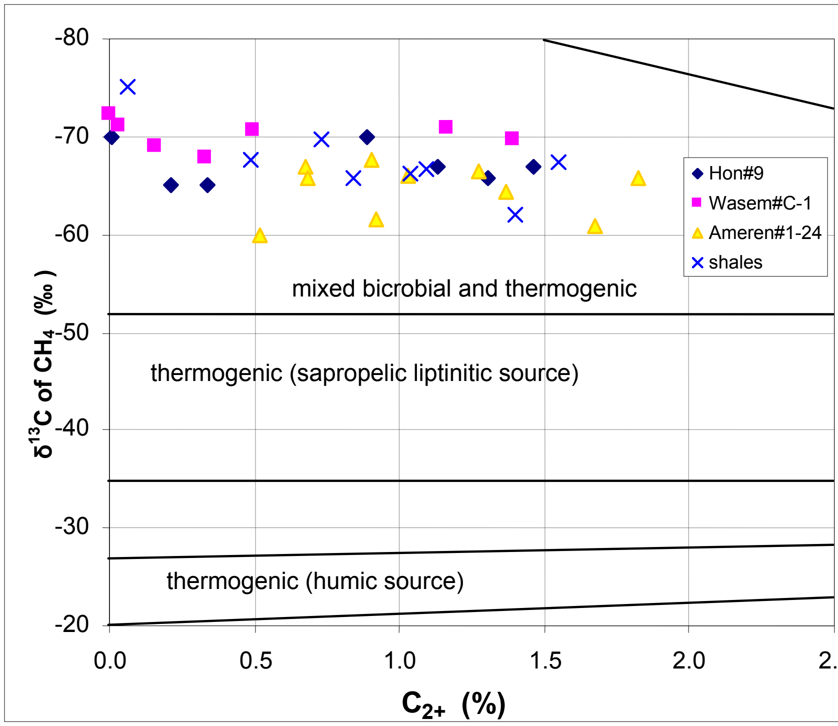


Figure 12. Carbon isotopic composition of methane as a function of wet gas content of coal gases for three individual wells and of shale gases for all three wells.

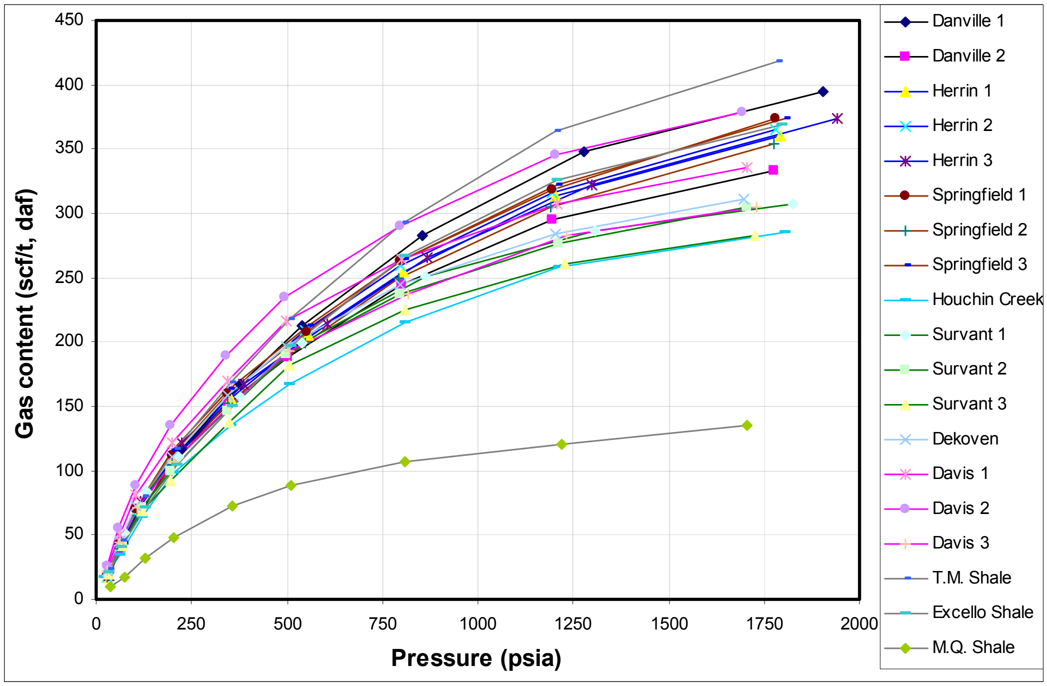


Figure 13a. Methane adsorption isotherms of coal and shale samples from Hon #9 well from White County, IL.

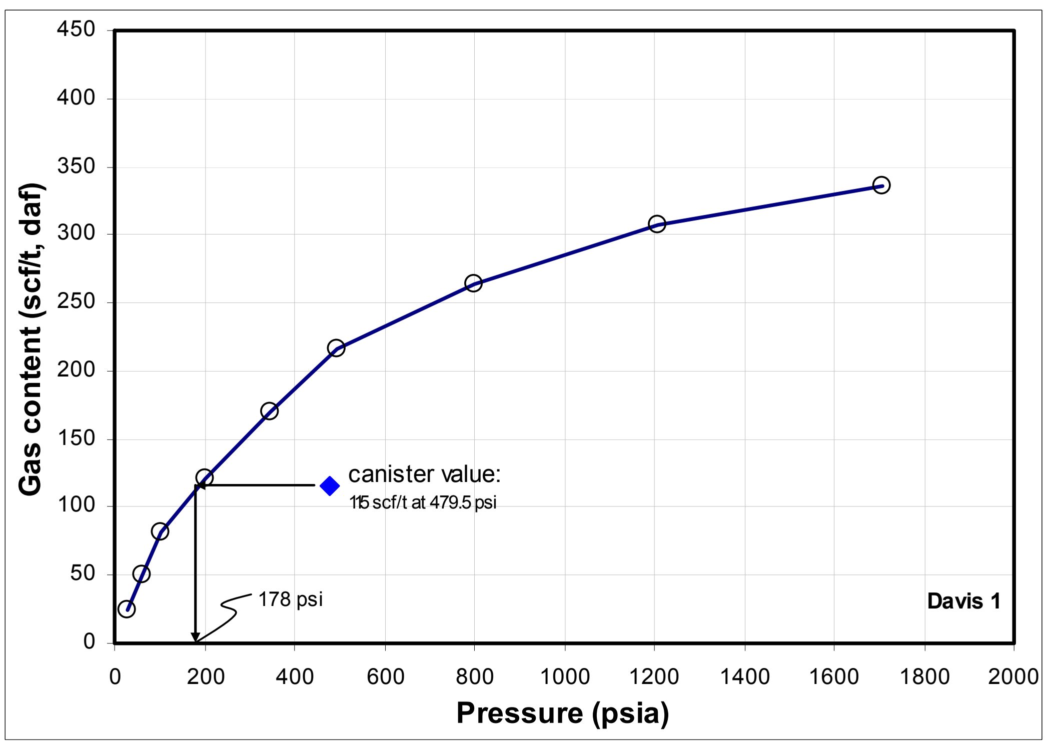


Figure 13b. Methane adsorption isotherms of sample 1 of Davis Coal from Hon #9 well from White County, IL. Methane saturation is 60.2%. Pressure would have to be reduced from ~480 psi to 178 psi in order to start methane desorption from the coal seam.

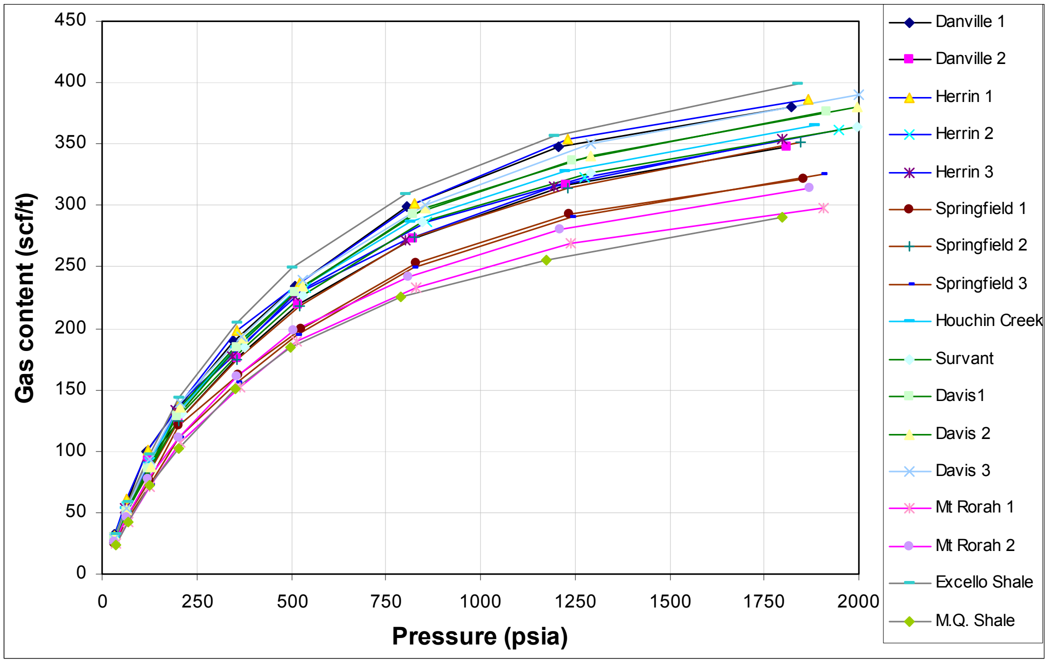


Figure 14a. Methane adsorption isotherms of coal and shale samples from Wasem #C-1 well from White County, IL.

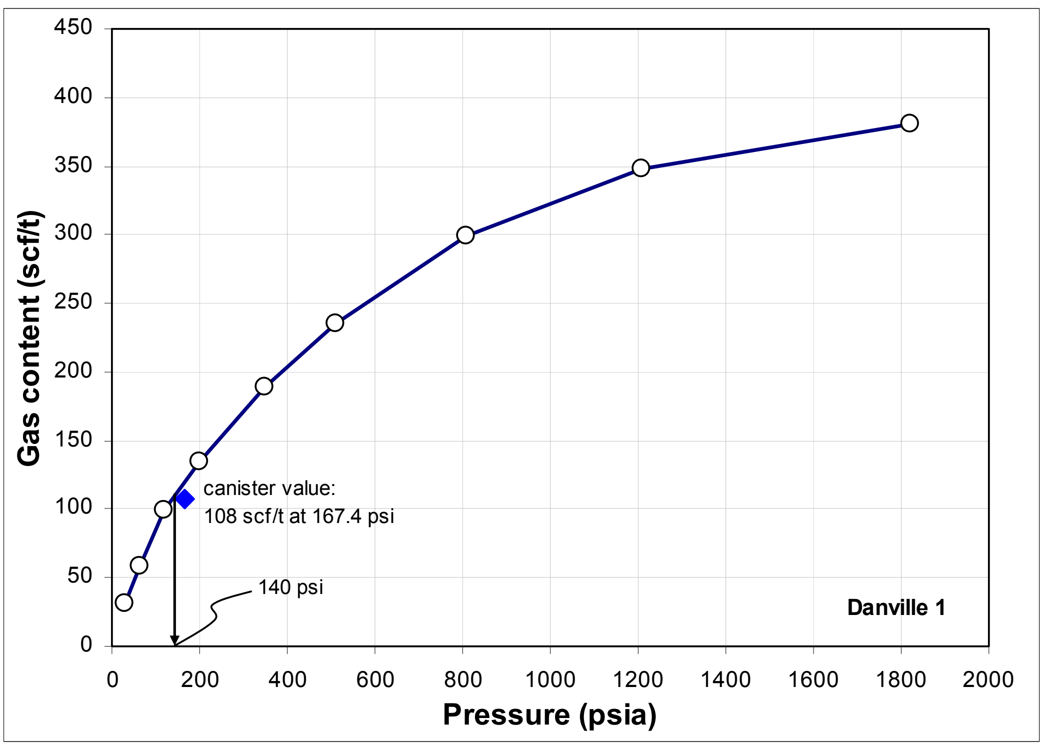


Figure 14b. Methane adsorption isotherms of sample 1 of Danville Coal from Wasem #C-1 well from White County, IL. Methane saturation is 91.3%. Pressure would have to be reduced from ~167 psi to 140 psi in order to start methane desorption from the coal seam.

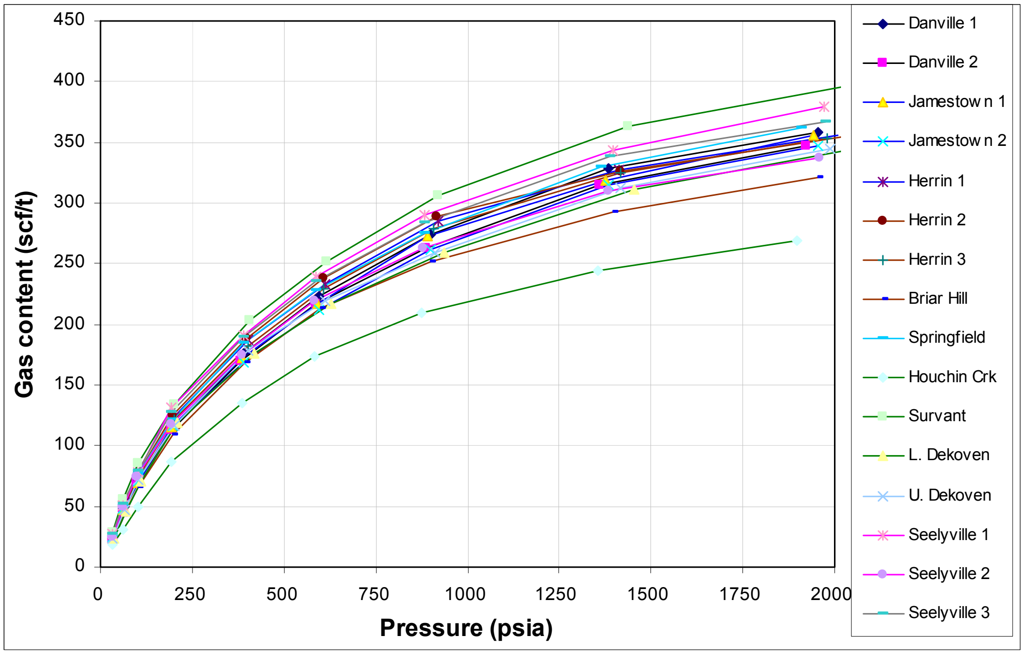


Figure 15a. Methane adsorption isotherms of coal and shale samples from Ameren#1-24 well from Jasper County, IL.

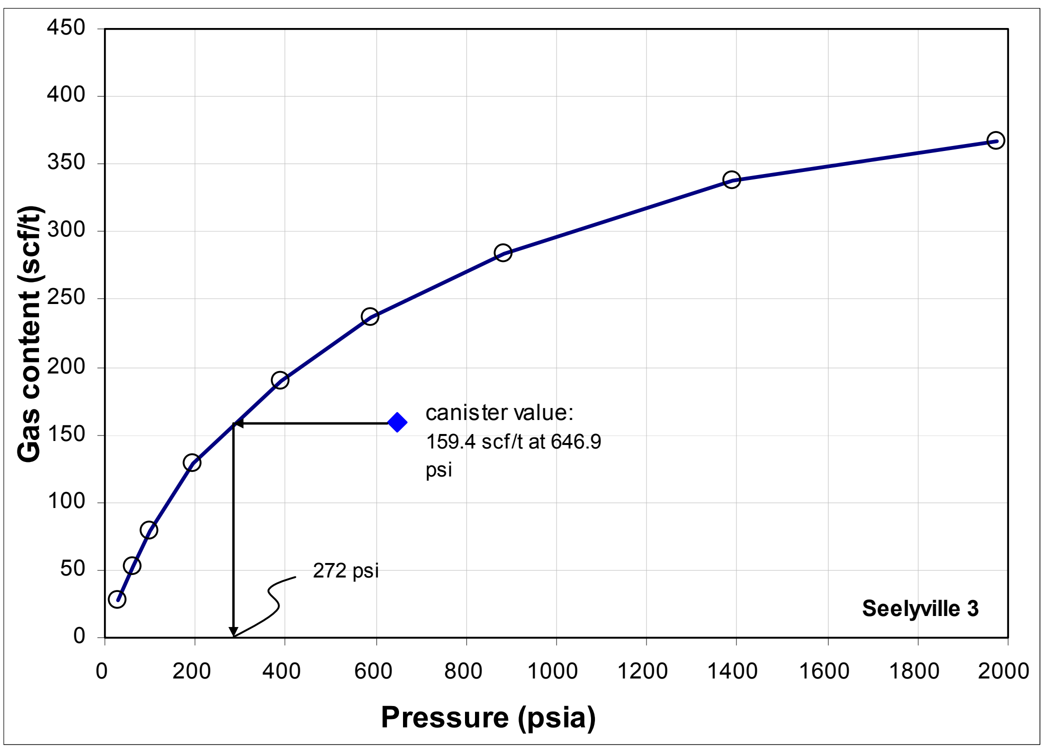


Figure 15b. Methane adsorption isotherms of sample 3 of Seeleyville Coal from Ameren#1-24 well from Jasper County, IL. Methane saturation is 62.1%. Pressure would have to be reduced from ~647 psi to 272 psi in order to start methane desorption from the coal seam.

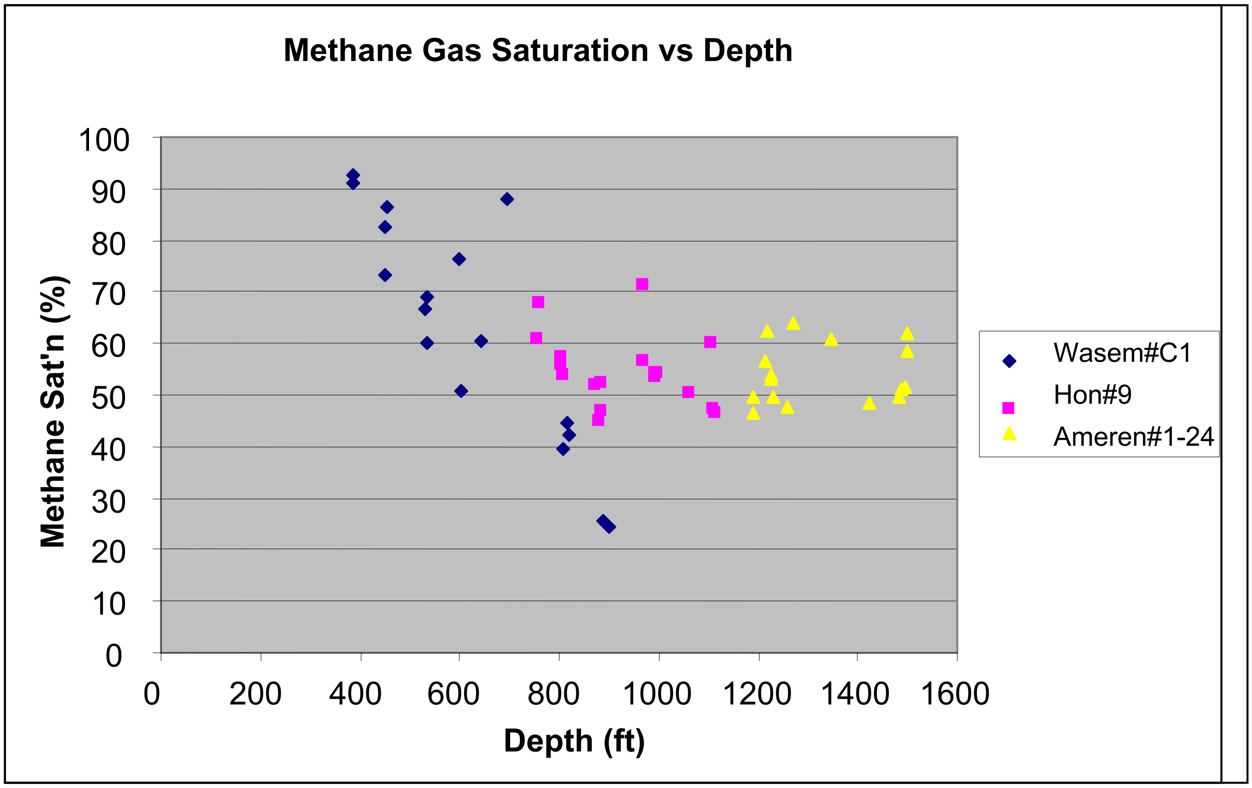


Figure 16. Methane saturation of coal samples from three wells.

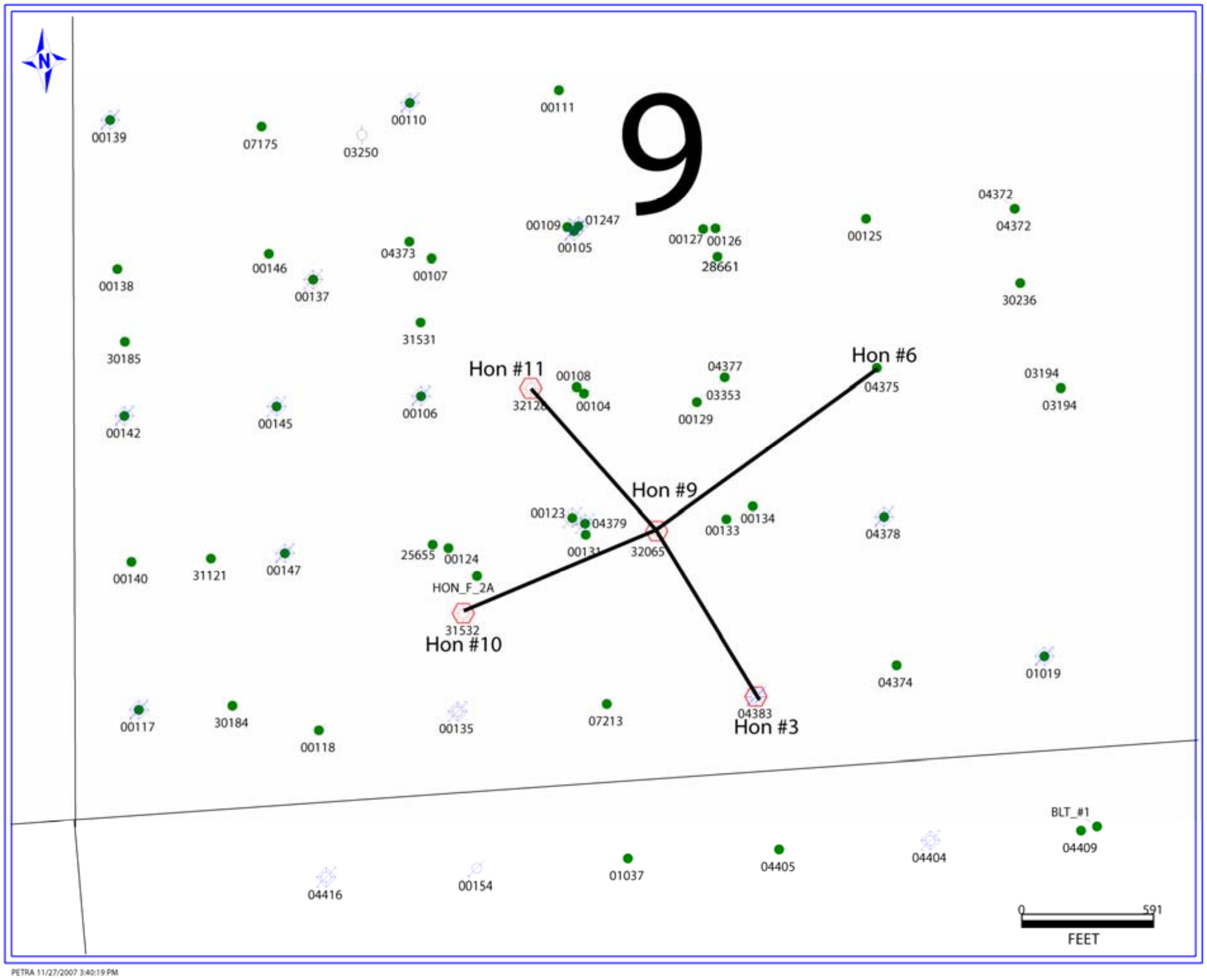


Figure 17. Pilot Project base map showing CBM (red symbols) and all other wells and cross-section locations. (south half, Sec. 9, T4S, R14W)

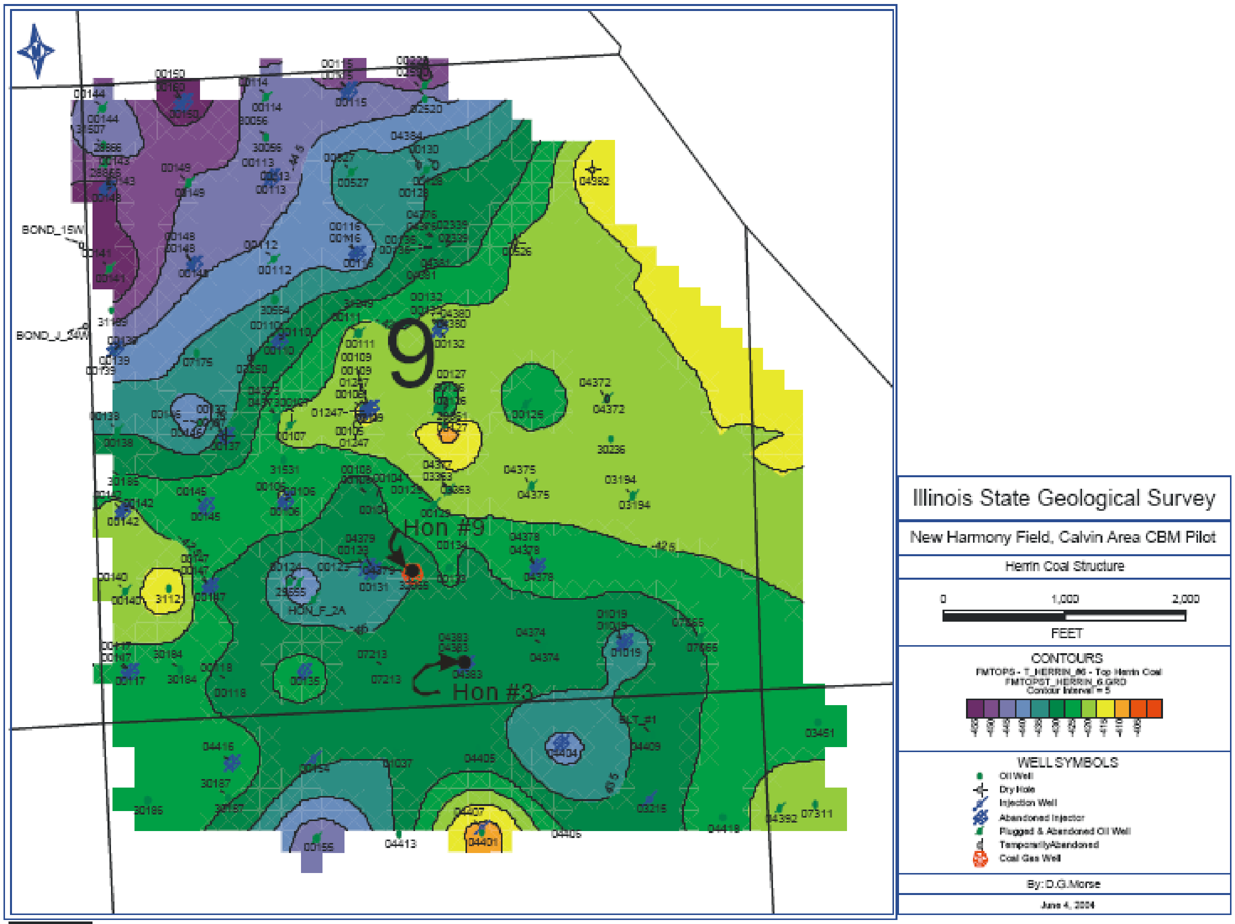


Figure 18. Herrin Coal structure map around the CBM pilot production test site in White County (Sec. 9, T4S, R14W).

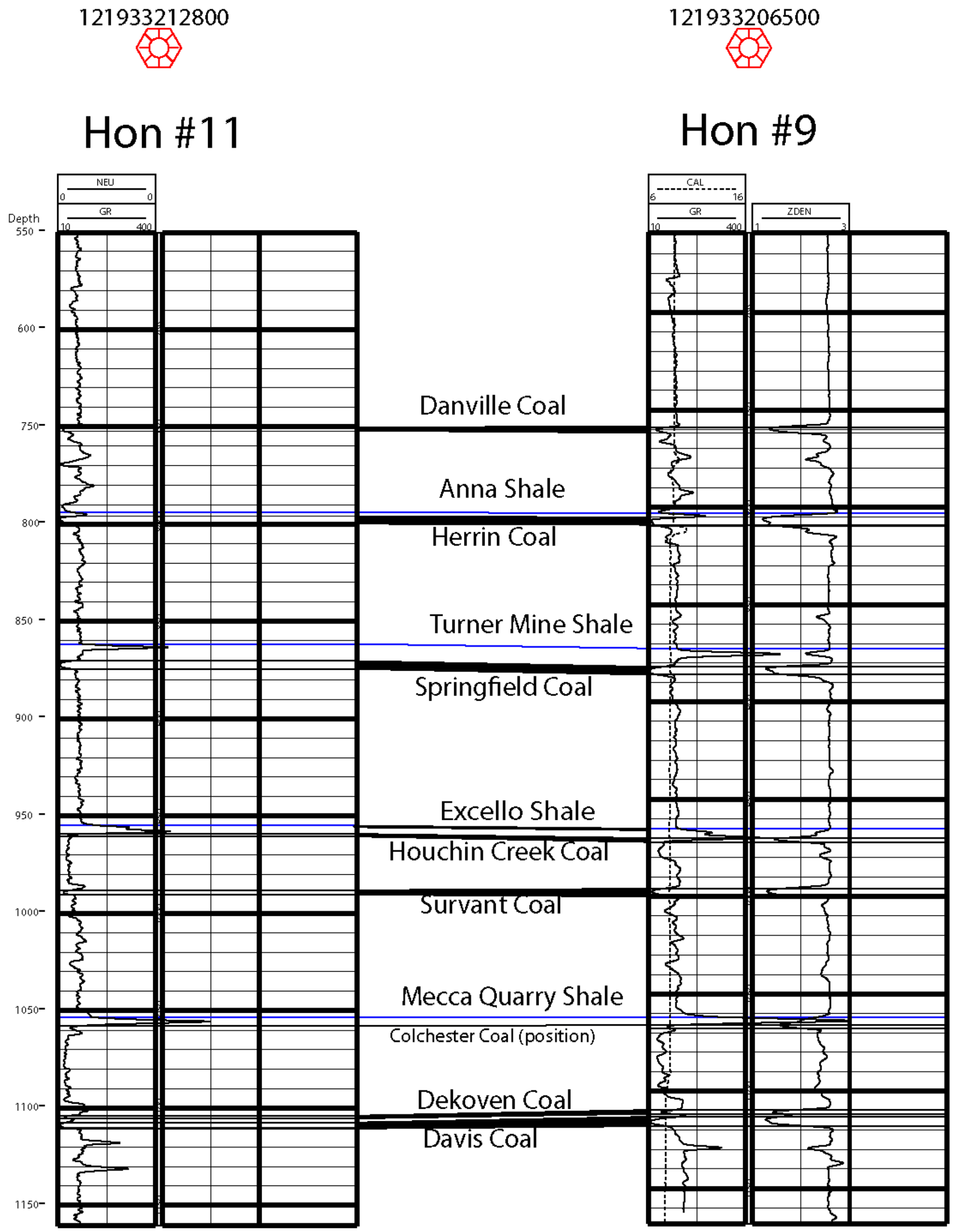


Figure 19. Stratigraphic cross-section from Hon #9 and Hon #3 wells in the pilot project area.

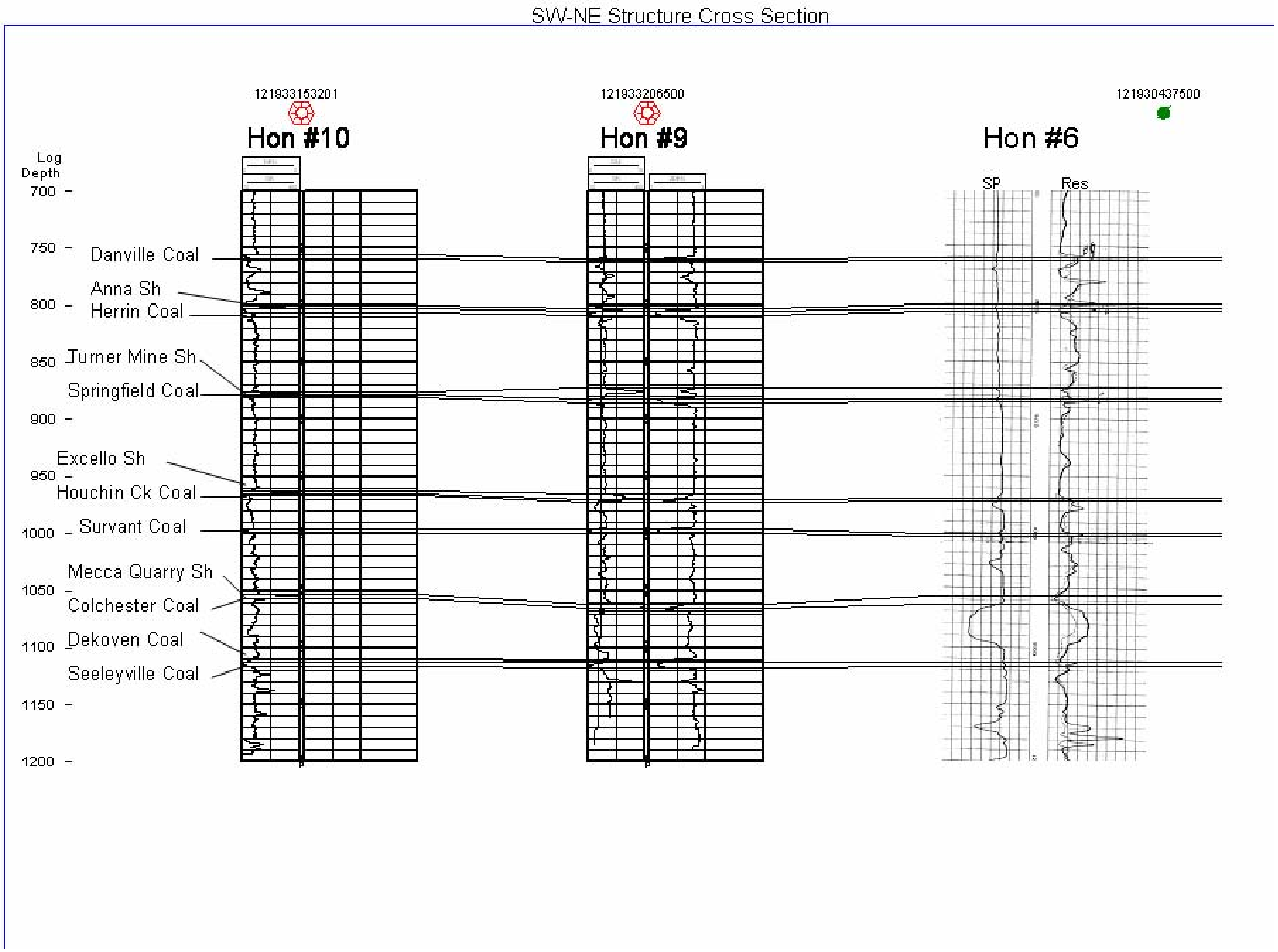


Figure 20. SW-NE Structural Cross Section across CBM Pilot Wells

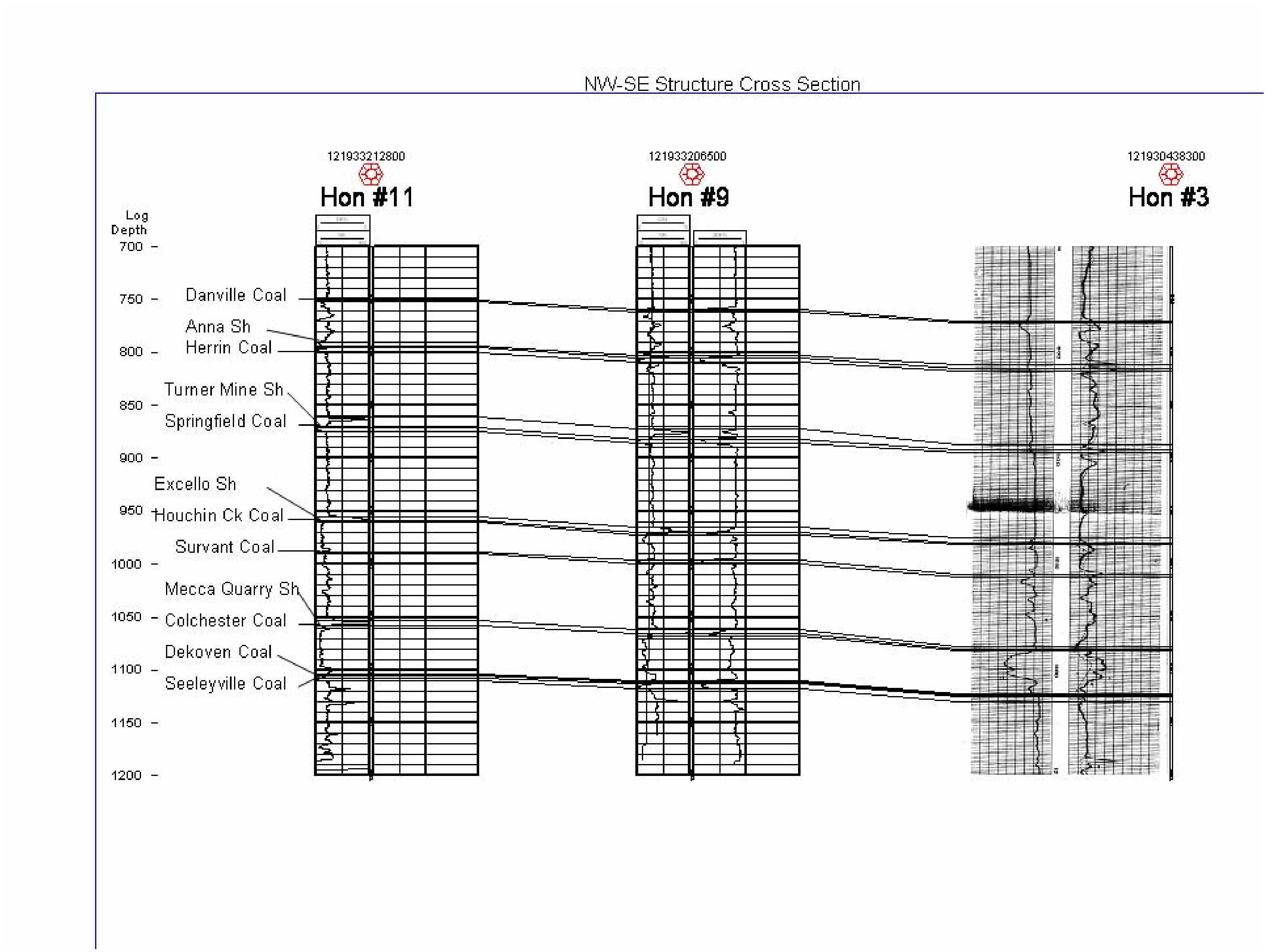


Figure 21. NW-SE Structural Cross Section across CBM Pilot Wells

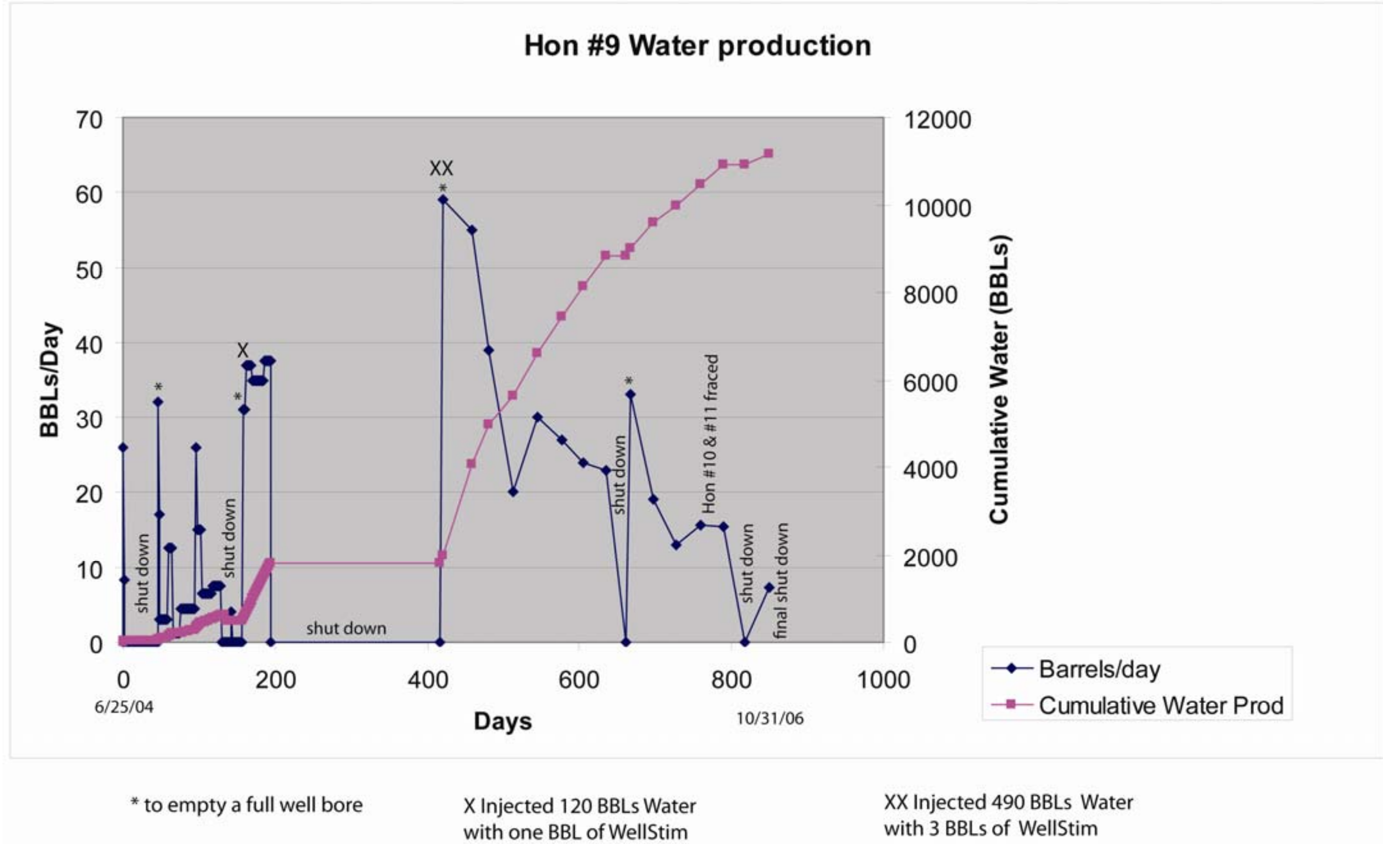


Figure 22a. Hon #9 water production history showing daily and cumulative production.

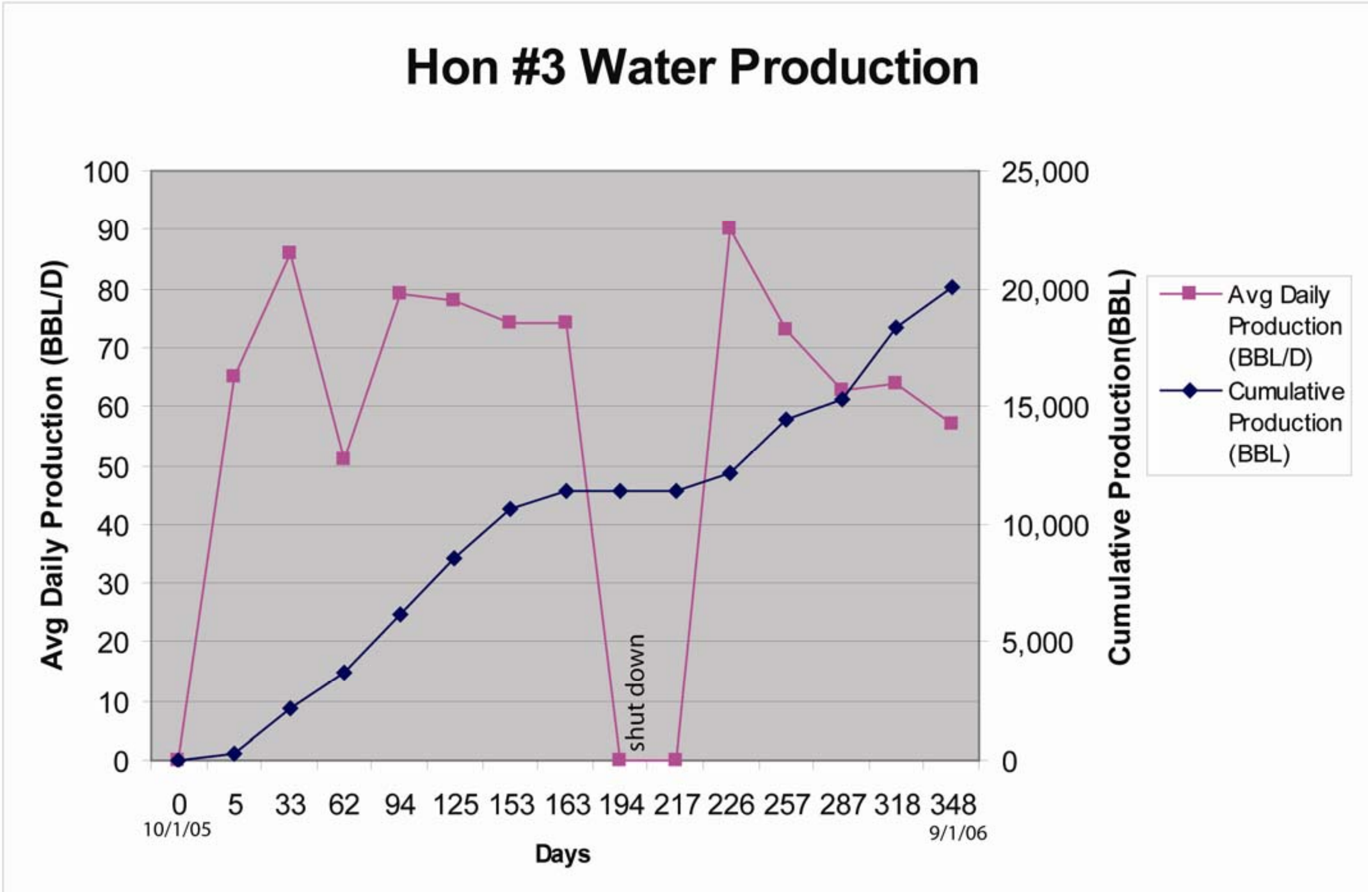


Figure 22b. Hon #3 water production history showing daily and cumulative production.

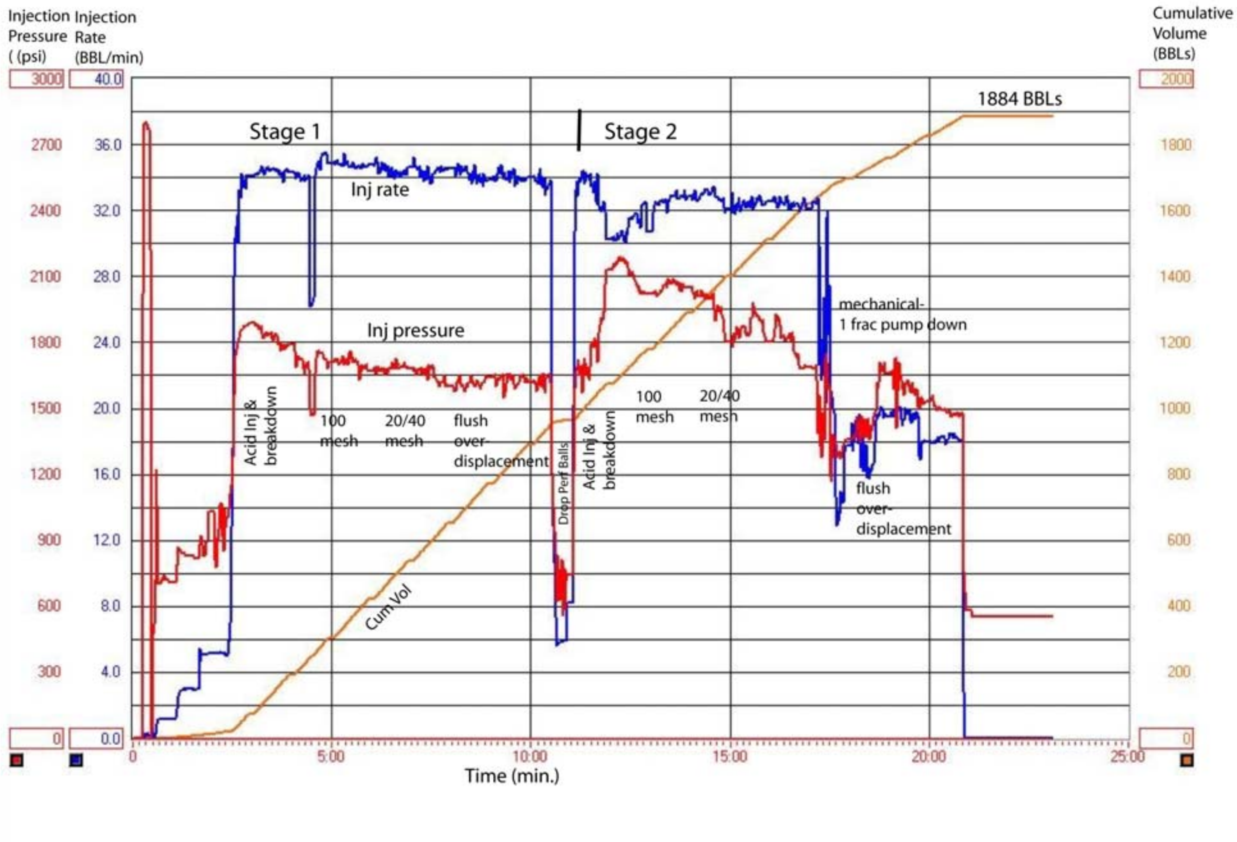


Figure 23. Hydraulic Frac Chart, Hon #10 well showing injection rate, injection pressure and cumulative fluid volume over the course the two stage frac job.

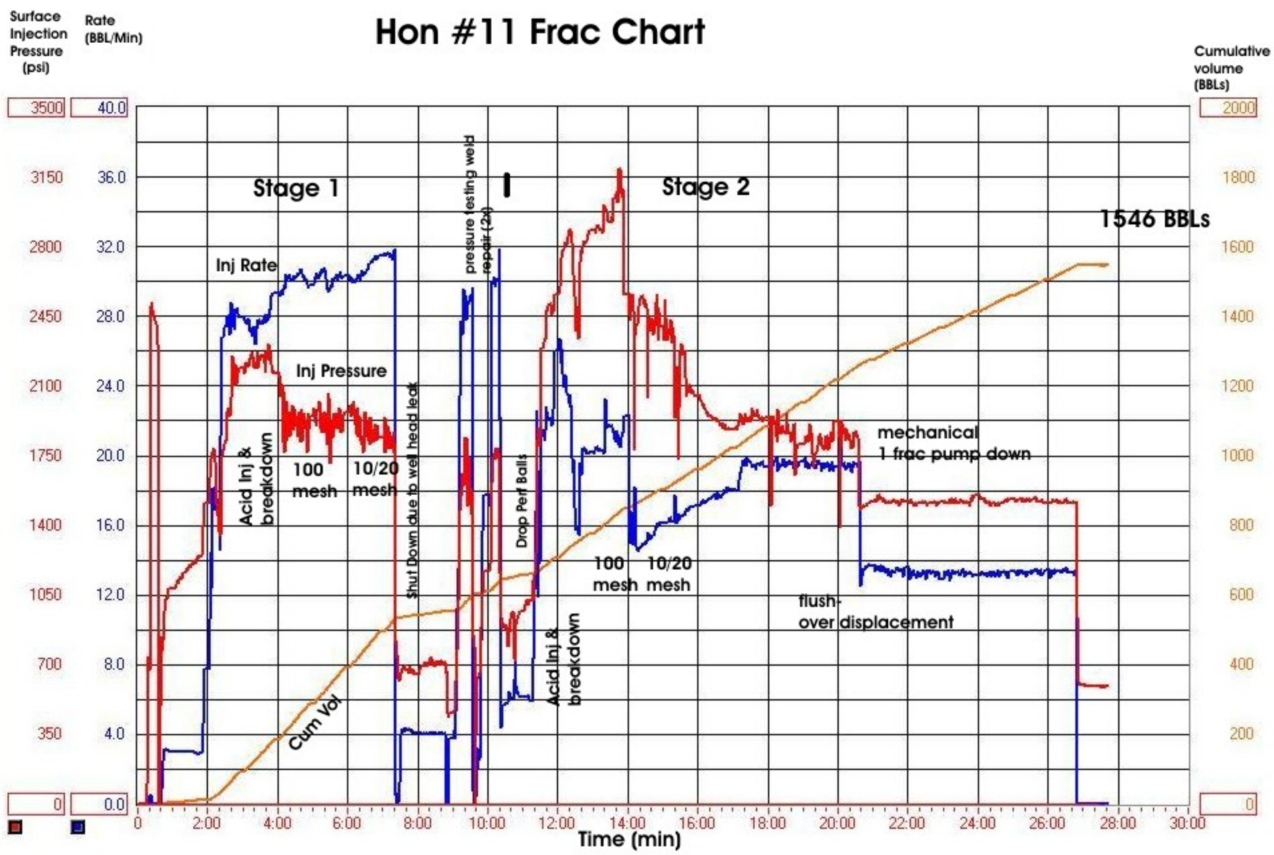


Figure 24. Hydraulic Frac Chart, Hon #11 well showing injection rate, injection pressure and cumulative fluid volume over the course of the two stage frac job.

Appendix 1a- Core Descriptions: Jim Cantrell #9 Hon Well
White County, Illinois

Depth (ft)		
From	**To**	
Core #1		
745.0	756.9	**Shale, m**edium grey, very evenly clay textured overall but locally very slightly silty, subfissile with only scattered local breaks on planar partings, sparse to locally common irregular nodules of either dolomite or dolomitic anhydrite.
756.9	757.1	Shale, dark grey, carbonaceous, fissile, broken.
		Danville Coal (from 757.1 to 760.6 ft)
757.1	757.25	Dull with bright bands, moderately high ash with clay and silt and grading to bone coal at top, subfissile at top, moderately cleated in bright lenses only, solid.
757.25	757.3	Dull, banded bright, moderately cleated in bright bands, solid.
757.3	757.7	Bright with common dull bands, moderately cleated in bright bands, sparse through-going master cleats, solid.
757.7	757.5	Canister desorption sample.
757.5	759.6	Bright with few dull bands, moderately to moderately well cleated in bright bands with cleats extending slightly into adjacent dull bands, sparse through-going master cleats, poorly developed butt cleats.
759.6	760.6	Canister desorption sample.
760.6	761.25	**Sandstone,** very fine (VF_L) to fine (F_U), poorly sorted, muddy, slightly micaceous, slightly carbonaceous and locally bearing coaly inclusions, rooted, very poor porosity and permeability.
761.25	761.8	**Sandstone,** fine (F_U), poorly sorted, muddy, locally micaceous, irregularly laminated, possibly flaser bedded in part, locally possible adhesion laminae, burrowed throughout, locally heavily burrowed to bioturbated, scattered distinct subvertical clay-lined burrows not of a recognizable form genus, porosity and perm poor.
761.8	765.0	**Sandstone,** medium (M_L), moderately sorted, slightly muddy, slightly micaceous, massive appearing but possibly with subtle crossbedding, fair porosity but poor permeability.
Core 2		
800.0	802.9	**Limestone**, light grey overall but grading dark grey and carbonaceous at both top and base, muddy, sparsely fossiliferous mudstone, contains many broken thin-walled pelecypods and other skeletal fragments, massive, very finely crystalline, tight.
802.9	803.0	**Shale**, black, carbonaceous, thinly laminated and interlaminated with coal, fissile, sparse through-going vertical fractures.
		Herrin Coal (from 803 to 806.5)
803.0	803.5	Bright, banded dull, clayey and bony in top ½ inch but clean below, moderately to moderately well cleated in bright bands on a very fine scale, sparse to locally some through-going master cleats which show partial mineralization with gypsum(?) or gypsum-after calcite and/or dolomite(?), master cleats are slightly curvilinear along their strike, partially broken.
803.5	804.5	Canister desorption sample.
804.5	805.0	Bright, banded dull, poorly to moderately cleated varying from band to band, very sparse through-going cleats, solid, interval contains ¾ -inch parting of bony coal at 804.75 and grades to bony coal at base.
805.0	806.0	Canister desorption sample.
806.0	806.4	Bright, banded dull, moderately to moderately well cleated within bright

		bands, few to common cleats that extend adjacent bands, very sparse through-going master cleats, many of the master cleats are mineralized with gypsum(?) and calcite.
806.4	806.5	Dull, bony, subfissile, solid.
806.5	806.7	Shale parting, dark grey, claystone, scattered coal inclusions, subfissile to irregularly fissile, traces of clay veins[1] near base but not penetrating the adjacent strata.
806.7	807.0	Bright, banded dull, moderately to moderately well cleated within bright bands, sparse to common cleats that penetrate adjacent bands, very sparse master cleats penetrating the bed, master cleats are mineralized and likely sealed with calcite, solid.
807.0	808.0	Canister desorption sample.
808.0	808.3	Bright, banded dull, moderately to moderately well cleated within bright bands, sparse to common cleats that penetrate adjacent bands, very sparse master cleats penetrating the bed, master cleats are mineralized and likely sealed with calcite, ½ -inch layer of dull, bony coal grading to black carbonaceous claystone at base.
808.3	810.5	**Claystone**, medium grey, slightly silty and slightly calcareous near base, rooted at top, locally partially cut by clay veins
810.5	813.0	**Claystone**, medium grey, calcareous, locally includes muddy limestone nodules, nodular and knotty, clay veins locally, bioturbated to heavily burrowed.
813.0	813.9	**Limestone**, medium grey, fossiliferous lime mudstone, very muddy and locally grades to limy claystone, few thin-walled brachiopods and other scattered fossil fragments, gradational top and base.
813.9	814.4	**Claystone**, medium grey, calcareous, locally includes muddy limestone nodules, locally nodular and knotty, few clay veins locally, burrowed.
814.4	816.9	**Sandstone**, light grey to white, fine (F_U) to medium (M_L) grading to medium (M_L-M_U) in lower one-third of unit, moderately to moderately well sorted, subrounded to rounded, quartzes, locally micaceous, locally calcareous, ripple bedded, irregularly wavy bedded with thin clay drapes in part, fair porosity and permeability overall, locally good porosity and permeability in thickly bedded, slightly coarser lower one-third, no hydrocarbon shows.
816.9	818.2	**Siltstone**, medium grey, clayey, poorly sorted, finely interbedded with silty clay shale, irregularly bedded, local starved ripples, locally grades to very muddy, very fine (VF_L), tight.
818.2	820.0	**Siltstone**, medium grey, clayey, very fine (VF_L) sandy, poorly sorted, locally interbedded with silty clay shale, irregularly bedded, locally ripple bedded, generally tight, locally grades to muddy very fine (VF_L) sandstone at about 819.0 ft which shows fair porosity.
Core 3		
867.0	872.6	**Shale**, medium grey, clay, locally slightly silty, widely scattered thin laminae of coarse siltstone finely interlaminated, scattered humic organic bits, widely scattered plant fossil debris and impressions in lower one-third, locally broken into 1- to 2-inch beds.
872.6	873.3	**Limestone**, medium grey, clayey, sandy, fossiliferous lime mudstone, increasingly sandy upward, contains minor broken and abraded fossil debris including crinoid and brachiopod fragments, grades to nodular calcareous shale at base.
873.3	874.0	**Shale**, very dark grey to black, clay, slightly silty, increasingly carbonaceous toward base with coaly inclusions and partings, increasingly calcareous

[1] Clay veins are pseudo-slickensided, curviplanar, subvertical dewatering features that superficially resemble slickensided fault surfaces, but represent an early post-depositional compaction feature created by dewatering of a peat, coal, porous sandstone, or carbonaceous shale through adjacent clay-rich rock. An abundance of these features is a cause of weak roof conditions in underground coal mines.

		upward, finely laminated at base and thickly laminated at top, locally sparsely burrowed with flattened horizontal feeding burrows, short conchoidal fractures but these do not penetrate the layer,.
874.0	875.0	**Shale canister desorption sample.**
875.0	875.2	**Shale**, black to very dark grey, clay, slightly silty, carbonaceous with coaly laminae and inclusions, finely laminated, poorly fissile, gradational base.
875.2	876.0	**Shale**, dark grey, clay, slightly silty, increasingly carbonaceous upward from slightly to moderately, poorly fissile.
876.0	880.6	**Shale**, medium grey, clay, slightly silty grading locally to silty, locally micaceous, thickly laminated and subfissile at top grading to thinly laminated and fissile at base.
 880.6	 880.7	**Springfield Coal (880.6 to 885 ft)** Dull with sparse bright bands, bony at top, subfissile, solid.
880.7	881.7	Canister desorption sample.
881.7	882.6	Coal, bright, banded dull, moderately cleated in bright bands, very sparse partings of dull bony coal locally, few cleats spanning adjacent dull bands, very sparse to rare through-going master cleats, solid.
882.6	883.6	Canister desorption sample.
883.6	884.6	Canister desorption sample.
884.6	885.0	Bright, blocky, moderately well cleated with common through-going cleats, cleats partially mineralized with calcite and gypsum(?); Coal, dull, bony, subfissile; Shale, black, clay, carbonaceous, subfissile to locally fissile, and; Pyrite, brassy, nodular, 3 cm thick and larger than 3-inch core, all as rubble.
Core 4		
960.0	962.2	**Shale**, medium to dark grey, clay, locally slightly silty, finely laminated, finely disseminated humic organic debris, scattered siderite nodules, hard, solid.
962.2	967.1	**Shale**, dark grey to black, clay, locally slightly silty, increasingly carbonaceous toward base, scattered bedform siderite nodules, few diminutive pelecypods and brachiopods locally near base, fissile to locally highly fissile.
967.1	967.4	**Sandstone**, light to light medium grey, fine (F_U) to very fine (VF_L), poorly sorted, muddy, micaceous, slightly calcareous, irregularly interbedded with dark grey shale similar to that described immediately above, very small-scale low-energy bedding features evident locally, possibly represents a flooding surface.
 967.4 968.25 968.6 969.6 969.75 970.0	 968.25 968.6 969.6 969.75 970.0 970.2	**Houchin Creek Coal (from 967.4 to 970. 2 ft)** Canister desorption sample. **Coal**, bright, banded dull, moderately cleated in bright bands and lenses, sparse cleats which penetrate adjacent bands, very sparse though-going master cleats, top contact is sharp and planar marked by a 1 mm thick lamina of carbonaceous shale, basal contact mineralized with pyrite. Canister desorption sample. Bright banded dull, moderately cleated in bright bands, few cleats spanning adjacent bands, very sparse through-going master cleats, master cleats mineralized with calcite, solid. Shale parting, very dark grey to black, clay, carbonaceous, fissile to subfissile. bright, banded dull, blocky, moderately to moderately well cleated in bright bands with many cleats extending through adjacent bands, fair butt cleat development, few cleats span the entire thin bed, solid, with ½-inch layer of dull, bony coal at base, sharp basal contact with burrowed and rooted sandstone below.
970.2	971.5	**Sandstone**, light grey, fine (F_U) to medium (M_L), poorly sorted, muddy, locally carbonaceous with local concentrations of organic debris, heavily rooted, bioturbation masking subtle hints of ripple bedding, fair porosity and permeability, sharp upper contact.
971.5	973.4	**Sandstone**, light grey, medium (M_L), poorly sorted, silty, slightly clayey,

		scattered carbonaceous debris, locally burrowed with clay-lined *Planolites*-like burrows, subtly ripple bedded and small-scale crossbedded.
973.4	979.0	**Sandstone**, light grey to white, medium (M_{L-U}), moderately to locally moderately well sorted, micaceous, commonly crossbedded, ripple bedded with micaceous carbonate drapes locally, fair to locally good porosity and permeability, scattered pyrite nodules locally concentrated along bedding planes.
978.9	980.0	core loss
<u>Core 5</u>		
979.0	983.2	**Shale**, light olive grey to olive grey, silty clay grading to clay, micaceous, locally pyritic, locally sideritic, scattered small calcite blebs locally, irregularly laminated, rubbly from 980.5 to 980.9, slightly carbonaceous at base.
983.2	993.2	**Shale**, dark grey, clay, locally slightly silty, increasingly carbonaceous toward base with first finely disseminated organic debris and then lower with humic fragments, locally siderite cemented, widely scattered siderite nodules, few widely spaced low-angle tectonic fractures, locally pyritic.
993.2	993.5	**Shale**, dark grey to very dark grey, clay, carbonaceous with coaly laminae and inclusions, fissile to subfissile.
		Survant Coal (from 993.5 to 997.5)
993.5	993.7	Dull, lenses bright locally, dusty, locally moderately to poorly cleated in bright lenses, very sparse cleats spanning adjacent bands, very sparse through-going master cleats.
993.7	993.8	**Shale**, very dark grey to black, clay, carbonaceous to locally very carbonaceous with coal inclusions and lenses, fissile to locally subfissile.
993.8	994.75	**Coal canister desorption sample.**
994.75	995.75	**Coal canister desorption sample.**
995.75	996.1	**Coal**, bright, banded dull, well developed through-going master face cleats at a fine (*c.* 4 mm) spacing, poorly developed butt cleats, few conchoidal irregular fractures, scant trace of gypsum(?) mineralization locally on cleat faces, partially broken.
996.1	996.3	**Shale**, dark to medium grey, carbonaceous at top and base, carbonaceous clay and coal inclusions throughout, fissile.
996.3	997.3	**Coal canister desorption sample.**
997.4	997.5	**Coal**, bright, banded dull, moderately well cleated in bright bands, moderately well developed through-going master face cleats, poorly developed irregular butt cleats, locally conchoidally fractured, increasingly dull and bony toward base, partially broken.
997.5	997.9	**Shale**, dark grey to black, clay, locally carbonaceous increasingly so toward top grading to bony dull coal, subfissile to poorly fissile, rooted.
997.9	999.0	**Claystone**, dark grey, grading from shaly at base to subfissile thence to nodular and massive upward, carbonaceous with root traces at top.
<u>Core 6</u>		
1045.0	1052.6	**Shale**, medium to medium dark grey, clay, locally silty, finely laminated, hard, few scattered calcareous siderite nodules in a zone 1051.0 to 1052.0, broken in bottom 1.5 ft.
1052.6	1055.4	**Shale**, dark grey, clay, locally slightly silty, slightly carbonaceous overall and increasingly so toward base, finely laminated, local siderite cemented bands.
1055.4	1058.0	**Shale**, dark to very dark grey, clay, carbonaceous, increasingly carbonaceous toward base, typically carbonaceous matter is disseminated throughout but sparse coaly inclusions near base, contains lenses and irregular thin interbeds of very fine (VF_L) muddy, slightly calcareous **Sandstone** at sporadic points between 1056.5 and 1057.0.
1058.0	1059.0	**Shale canister desorption sample.**
1059.0	1062.1	**Shale**, black, carbonaceous with finely disseminated humic matter, locally

		irregular blebs and small nodules of crystalline pyrite, fissile.
1062.1	1062.3	**Shale**, black, silty clay, sandy, very carbonaceous grading to dull bony coal at base, fissile, broken to locally rubble.
 1062.3 1062.5 1063.5	 1062.5 1063.5 1063.6	**Dekoven Coal (from 1062.3 to 1063.6)** Bright, blocky, moderately to locally poorly cleated, sparse cleats spanning adjacent bands, very sparse through-going master cleats, cut by conjugate set of tectonic fractures, fractures and master cleats are partially mineralized with a surface film of calcite, solid to locally broken. **Coal canister desorption sample.** **Coal**, dull, bony, and; **Shale**, black, slightly silty clay, carbonaceous, locally pyritic, hard, rubble.
1063.6	1065.0	core loss
<u>Core 7</u>		
1079.0	1099.0	**Sandstone**, light grey, grading from medium (M_L) to very coarse (VC_L), moderately well to moderately sorted, in stacked fining upward bed sets, interval fines upward overall, crossbedded, locally ripple bedded, locally planar bedded, can be interpreted as a succession of stacked channel bars, filling a fluvial or fluvio-deltaic channel, locally contains clay, carbonaceous clay and coal clasts, good porosity and permeability.
<u>Core 8</u>		
1099.0	1101.0	**Sandstone**, light grey, grading from medium (M_L) to very coarse (VC_L), moderately well to moderately sorted, locally coarse-tail lag, in stacked fining upward bed sets, interval fines upward overall, crossbedded, locally ripple bedded, can be interpreted as a succession of stacked channel bars, filling a fluvial or fluvio-deltaic channel, locally contains clay, carbonaceous clay and coal clasts, sharp erosional base, good porosity and permeability
1101.0	1107.0	**Shale**, medium grey, slightly silty clay, laminated, subfissile to locally fissile, widely scattered discrete laminae of fine siltstone interbedded.
1107.0	1107.1	**Sandstone**, black, very carbonaceous, muddy, grades to sandy carbonaceous mudstone, hard, tight.
 1107.1 1107.4 1108.5	 1107.4 1108.5 1108.9	**Davis Coal (from 1107.1 to 1114.9)** Bright, banded to locally dull, moderately cleated, broken and rubble. **Coal canister desorption sample.** Coal, bright, banded dull, moderately well cleated in bright bands, some cleats span across adjacent bands, through-going master face cleats present at *c.* 0.15 ft spacing, partially broken.
1108.9 1109.75 1110.7 1110.8 1111.0 1111.25 1112.3 1113.0 1113.5	1109.75 1110.7 1110.8 1111.0 1111.25 1112.3 1113.0 1113.5 1113.6	Claystone, carbonaceous, irregularly bedded, cut by numerous short clay veins (*see footnote 1 above*). Coal, bright, banded dull, poorly to moderately cleated with majority of cleats confined to bright bands only, few cleats span adjacent dull bands, solid, locally pyritic. Shale, black, carbonaceous, interlaminated with coal and bone laminae and partings. Coal, dull, with both bone and few bright laminae. Coal, bright, banded dull, blocky, moderately to moderately well cleated with majority of cleats spanning multiple bands, few through-going master face cleats at *c.* 0.1 spacing, bony coal parting at 1111.2 ft. **Coal canister desorption sample.** Coal, bright, banded dull, moderately to locally poorly cleated primarily in bright bands, few cleats span adjacent dull bands, sparse through-going master cleats show calcite mineralization. Coal, dull, bony, highly pyritic, common claystone interlaminations and partings. Coal, bright, banded dull, moderately cleated in bright bands, few cleats span

		adjacent dull bands, few short discontinuous master cleats commonly sealed with calcite mineralization.
1113.6	1114.6	**Coal canister desorption sample.**
1114.6	1114.9	Coal, bright, banded dull, moderately cleated, few cleats spanning adjacent bands, sparse master cleats with common calcite mineralization.
1114.9	1115.0	Claystone, light grey, massive, carbonaceous, rooted.
1115.0	1115.9	Sandstone, dark grey, fine (F_{L-U}), poorly sorted, muddy, very muddy near top, carbonaceous, locally slightly calcareous with patchy calcite cement in lower one-half, rooted, bioturbated, tight, gradational basal contact.
1115.9	1119.0	Limestone, medium to medium dark grey, lime mudstone, sandy, clayey, locally marly, heavily burrowed to bioturbated, nodular to irregularly bedded, tight.

Appendix 1b – Core Description: Howard Energy C-1 Wasem Well,
Section 24, T7S, R10E, White County, Illinois

Core 1: 370.0 – 390.1 ft.

370.0 – 384.2 Shale, medium gray (N4.5), clay, scattered siderite nodules which conform to bedding and may be platy in overall form, locally siderite cemented claystone zones, dispersed macerated plant debris in many beds, slightly pyritic locally, slightly calcareous locally, thinly bedded to thickly laminated, irregularly bedded in part, fissile to subfissile, hard.

384.2 – 382.4 Shale, medium dark gray (N3.5), clay, fossiliferous with brachiopod-gastropod fauna, common plant debris, thin bedded, hard.

382.4 – 386.1 Shale, dark gray (N3), clay, dispersed macerated plant debris, locally carbonaceous near base, thin bedded, hard.

386.1 – 386.5 Shale, dark gray to dark brownish gray (N3 – 5YR2/1), carbonaceous, very carbonaceous near base grading to bony coal, fossiliferous in part, locally pyritic, , thinly laminated, fissile, hard.

386.5 – 388.9 **Danville Coal**, banded bright to banded dull, locally dull at top, moderately well cleated, good face cleat development, fair butt cleat development, patchy calcite cement filling cleats locally but not pervasively, locally pyritic near base, canister desorption samples taken 386.7–387.7 and 387.7–388.7.

388.9 – 389.3 Claystone, dark gray to medium light gray (N3 – N6), common macerated plant debris, root traces, mottled texture, firm to hard, softens when wet, underclay.

389.3 – 390.1 Claystone, medium gray (N5), silty, locally very fine sandy, very poorly sorted, locally micaceous, root traces, possibly burrowed in part, mottled texture, hard.

Core 2: 431.0 – 444.0 ft.

431.0 – 433.1 Shale, medium gray (N5), silty, locally very fine sandy, poorly sorted, locally grades to clayey siltstone, slightly micaceous, irregularly bedded, thinly bedded, hard.

433.1 – 435.0 Claystone, medium dark gray to dark brownish gray (N4 – 5YR3/0.5), locally calcareous, increasingly calcareous toward base, scattered carbonaceous debris, scattered fragmentary fossil debris near base, poorly bedded, knotty, firm to locally hard, breaks into many irregular chips.

435.0 – 435.4 Limestone, clayey packstone, carbonaceous, argillaceous, brachiopod fauna, tight.

435.4 – 436.0 Siltstone, dark gray (N2.5 – N3) grading to dark greenish gray (5GY3/0.5), fine to coarse silt, clayey, calcareous, locally sideritic, abundant plant debris, poorly bedded to locally massive, bioturbated(?), tight.

436.0 – 437.8 Sandstone, very fine to locally fine near top coarsening up from silty sandy dark gray (N3) shale, poorly sorted, fine skewed, muddy, micaceous, slightly carbonaceous locally, calcite cemented, burrowed, irregularly bedded, thinly bedded, tight.

437.8 – 439.1 Shale, dark gray (N3), silty, locally slightly sandy, poorly sorted, calcareous, increasingly carbonaceous toward base, calcareous microfauna (forams?) and scattered broken fossil debris, irregularly bedded, thin bedded, locally convolute bedding, hard.

439.1 – 439.6 Shale, very dark gray to black (N2 – N1), very carbonaceous, possible phosphatic blebs, thinly laminated, fissile, hard.

439.6 – 440.5 Shale, dark gray (N3), silty, calcareous, increasingly abundant thin shell fauna downward, thickly laminated to thin bedded, gradational basal contact, hard.

440.5 – 444.0 Shale, dark gray (N3), silty, calcareous, fossiliferous, thickly laminated, irregularly laminated, hard.

Core 3: 444.0 – 464.2 ft.

444.0 – 447.8 Shale, dark gray (N3) silty, calcareous, fossiliferous, irregularly bedded, thickly laminated, hard.

447.8 – 455.0 **Herrin Coal**, banded bright to locally banded dull, moderately cleated, cleat height greatly variable from band to band, variable amount of calcite lining and partial fill in cleats but particularly filling the high through-going master cleats, thick clay shale parting at 448.8–448.9, "Blue Band" claystone at 451.8–452.0, local irregular zones of clayey (high ash) coal widely scattered throughout the seam, locally pyritic in discrete laminae as well as dispersed crystalline pyrite, canister desorption samples taken 449.0–450.0; 450.0–451.0; 452.8–453.8.

455.0 – 459.9 Sandstone, fine locally coarsening upward overall from very fine to medium, poorly sorted, silty, locally muddy, carbonaceous in top 0.2 ft., root traces in top 1.6 ft., locally pyritic, burrowed, some disrupted bedding, fair porosity and permeability.

459.9 – 462.2 Sandstone, fine to very fine, poorly sorted, muddy, spotty siderite cement, micaceous, indistinctly ripple laminated, thinly bedded, small-scale cut-and-fill structures, locally shows drapes of organic-rich mudstone, locally burrowed, poor porosity and permeability.

462.2 – 464.2 Siltstone, fine silt, clayey, very fine sandy, poorly sorted, thinly bedded to thickly laminated, burrowed in part, pillow structures, small-scale cut-and-fill structures, increasingly shaly near base, tight.

Core 4: 519.0 – 538.9 ft.

519.0 – 527.6 Shale, medium gray to light brownish gray (N5 – 5YR5/0.5), clay, dispersed plant debris scattered throughout, slightly calcareous overall, locally calcareous, few siderite nodules in lower half and increasingly abundant in lower 2.0 ft, locally siderite cemented, thinly bedded to thickly laminated, subfissile to locally fissile, rare burrows, hard to locally firm.

527.6 – 529.9 Shale, dark gray (N3 – N3.5), clay, locally slightly silty, fossiliferous with crinoid-brachiopod-pelecypod fauna, shell lags locally, with lime mudstone nodules in basal 0.5 ft, calcareous with both fossil debris and cement, locally burrowed, subfissile to fissile, hard.

529.9 – 530.4 Limestone, medium dark gray to medium gray (N 4.5 – N5.5), fossiliferous lime mudstone, argillaceous, thickly bedded, tight.

530.4 – 530.6 Shale, dark gray (N3), clay, fossiliferous with brachiopod-pelecypod fauna, calcareous, thinly bedded to thickly laminated, subfissile to fissile, hard.

530.6 – 532.2 Shale, grayish black to black, carbonaceous, rich in finely macerated plant debris, increasingly carbonaceous in lower 1 ft. grading to bony coal at base, fine silty laminae locally, fissile to subfissile, firm to hard.

532.2 – 537.3 **Springfield Coal**, banded bright, moderately well to locally well cleated, some calcite mineralization along through-going primary face cleats, scattered thin (1–10 mm) partings throughout, locally pyritic, calcareous cleat fillings rather pervasive, solid, thick parting of carbonaceous pyritic black shale at 530.0 to 536.3, dull bands locally in basal 1.3 ft, canister desorption samples taken 532.1–533.1; 533.1–534.1; 535.0–536.0.

537.3 – 538.9 Claystone, medium gray (N4.5), rooted in top 1 ft, slightly silty near base, slips locally, subfissile, firm to hard.

Core 5: 595.0 – 615.0 ft.

595.0 – 598.3 Shale, medium gray to medium dark gray (N5 – N3.5), clay, locally slightly silty, calcareous streaks and discontinuous thin (<5 mm) interbeds and lenses of limestone locally, sparsely fossiliferous with thin-shelled brachiopod fauna, few scattered siderite nodules, subfissile to fissile, hard.

598.3 – 599.6 Shale, dark grayish black to black (N2 – N1), carbonaceous, calcareous with streaks and lenses of limestone, irregularly laminated, subfissile to locally fissile, hard.

599.6 – 600.6 Siltstone, medium gray (N5), fine silt, clayey, sandy grading locally to very fine sandstone, poorly sorted, carbonaceous, contains some large fragmentary plant remains, locally sideritic, hard.

600.6 – 602.9 Shale, black (N1), carbonaceous with abundant finely macerated plant debris, locally slightly calcareous near top, hard, canister desorption sample taken 601.0–602.0 ft.

602.0 – 604.9 **Houchin Creek Coal**, banded bright, moderately well to well cleated, dull poorly cleated bands locally, solid in part, broken in part, calcite linings and seals in through-going fractures and face cleats, sharp planar top, canister desorption sample taken 603.6–604.6 ft.

604.9 – 605.1 Claystone, dark gray (N4), silty, carbonaceous, subfissile, rooted, grades to siltstone as described below, firm to hard.

605.1 – 607.1 Siltstone, greenish gray (5GY5.5/1), clayey, very fine to fine sandy, rooted, mottled texture, hard, fair porosity and permeability despite poor sorting.

607.1 – 615.0 Sandstone, fine to very fine, poorly sorted, fine skewed, top 1.8 ft is deeply rooted and possibly burrowed with mottled texture, remainder is finely laminated and cross-laminated with very low amplitude ripple beds and small-scale cut-and-fill structures, subtle sense of incomplete tidal bundles, *Planolites* and *Palaeophycos* burrows among other indeterminate forms, increasingly burrowed below 610 ft., many burrows siderite cemented, fair porosity and permeability despite poor sorting.

Core 6: 640.0 – 660.0 ft.

640.0 – 642.3 Shale, dark gray (N3 – N3.5), clay, slightly silty, calcareous locally, common nodules of siderite and calcareous siderite, thinly laminated, irregularly laminated, subfissile to fissile, breaks into chips, hard.

642.3 – 645.8 Shale, medium dark gray (N4 – N4.5), clay, locally slightly silty, common siderite nodules scattered throughout, burrowed locally, subfissile, hard.

645.8 – 647.5 **Survant Coal**, banded bright, locally banded dull, moderately well cleated, scant calcite linings on cleat faces, rubble in part, bony coal in top 0.1 ft., sharp basal contact, rubble in part, canister desorption sample taken 658.8–647.0 ft.

647.5 – 648.4 Claystone, medium dark gray (N4), carbonaceous with scattered large plant fragments, slightly silty locally, gradational base, subfissile, breaks into chips, firm to hard but softening when wet.

648.4 – 649.1 Coal, banded dull to locally banded bright, moderately well cleated, locally well cleated in bright bands, locally pyritic, grades to carbonaceous shale at top and base, broken.

649.1 – 649.2 Claystone, medium dark gray (N4), rooted, subfissile, firm to hard.

649.2 – 650.4 Sandstone, very fine to locally fine, poorly sorted, muddy, locally grades to clayey coarse siltstone, laminated in part, subtle suggestion of incomplete tidal bundles, burrowed, *Palaeophycos*, poor porosity and permeability.

650.4 – 651.3 Sandstone, fine to medium fining upward, poorly to moderately sorted, silty, locally muddy, burrowed, some convolute bedding, poor to fair porosity and permeability.

651.3 – 652.0 Sandstone, very fine to fine, poorly sorted, muddy, laminated, deformed bedding at top, locally burrowed, poor porosity and permeability.

652.0 – 653.3 Sandstone, medium, moderately sorted, locally silty, carbonaceous clasts and flecks, micaceous laminated near top, crossbedded in lower 0.8 ft., fair porosity and permeability.

653.3 – 654.0 Sandstone, very fine, muddy, finely laminated, small-scale cut-and-fill structures, tight.

654.0 – 656.6 Shale, light medium gray to light medium olive gray (N6 – 5YR6/0.5), poorly sorted, silty with abundant admixed silt and siltstone streaks, locally sideritic with cement and nodules, sparsely burrowed, subfissile, hard.

656.6 – 658.0 Sandstone, fine to very fine, poorly sorted, muddy, finely laminated, locally disrupted by heavy burrowing and soft sediment deformation, subtle suggestion of tidal bundles, bidirectional ripple bedding near base, poor porosity and permeability.

658.0 – 660.0 Sandstone, fine to medium, poorly to moderately sorted, muddy, carbonaceous flecks, locally sideritic, bioturbated in top 0.4 ft., burrowed, contorted bedding and slumps, fair porosity and permeability.

Core 7: 685.0 – 705.0 ft.

685.0 – 694.8 Shale, dark gray (N3 – N4) clay, locally silty, locally pyritic, fissile, hard. This unit contains scattered thick interbeds or large (>> core diameter) nodules of dolomitic siderite which locally preserve burrows and fossil fragments. In some cases, these may have originally been limestone beds in some cases, with the dolomite and siderite replacing the calcite, or they are very early carbonate cemented horizons in the shale. In other cases, the nodules are diffuse-edged nodular cemented zones within the shale.

694.8 – 697.7 Shale, dark grayish black to black (N2 – N1), very carbonaceous, rich in finely macerated plant debris and possibly some sapropelic organic matter, fissile, platy, canister desorption sample taken 696.5–697.5 ft.

697.7 – 697.9 Coal, banded bright, moderately cleated, broken.

697.9 – 700.0 Sandstone, fine, poorly sorted, muddy, carbonaceous in top 0.3 ft., scattered carbonaceous flecks and root traces, mottled texture with rooting and possible burrowing, massive, poor porosity and permeability.

700.0 – 705.0 Sandstone, medium, moderately sorted, silty in upper 1.8 ft. and slightly silty below, ripple bedded, locally suggestions of flaser bedding, small-scale cut-and-fill structures, mottled (burrow-mottled?) near base, fair porosity and permeability.

Core 8: 807.0 – 827.0 ft.

807.0 – 807.2 Shale, dark gray to grayish black (N2 – N1.5), carbonaceous, fissile, hard.

807.2 – 808.6 **Davis Coal** (from 807.2 to 820.5, excluding the parting between 808.6 and 815.9). The upper part is banded bright to locally dull, moderately cleated, calcite mineralization of cleats locally, 0.2-ft. pyritic claystone at 807.4 ft., canister desorption sample taken 807.6–808.6 ft.

808.6 – 809.5 Claystone, medium dark gray (N4), slightly silty locally, heavily rooted, carbonaceous root traces well preserved, numerous slips, massive to subfissile, firm to hard but softens when wet.

809.5 – 815.9 Shale, dark gray to black (N3 – N1.5), locally slightly silty in upper half, carbonaceous, increasingly carbonaceous in basal 0.6 ft., locally pyritic, slightly calcareous in lower one-third, widely scattered siderite cemented zones and diffuse-edged siderite nodules, calcite mineralized fracture or vein at 811.9 ft., fissile, breaks into chips locally, platy near base.

815.9 – 820.5 Coal, banded bright with few scattered dull benches, bony coal to carbonaceous shale split at 818.0–818.3 ft., well cleated with numerous well developed through-going master face cleats, butt cleat less well developed but present in evidence commonly, minor patchy calcite mineralization of face cleats only locally pervasive, largely solid to locally broken, canister desorption samples taken 816.8–817.8, 818.3–819.4.

820.5 – 823.3 Sandstone, very fine to fine, poorly sorted, muddy, micaceous, carbonaceous to very carbonaceous in top 1.6 ft., rooted, calcite nodules and calcified rhizoliths, patchy calcite cement, bioturbated in part, mottled texture, poor porosity and permeability.

823.3 – 825.2 Sandstone, fine, moderately sorted, silty, locally muddy, soft sediment deformation features locally, burrowed and possibly rooted, originally laminated but partially disrupted to resemble the unit above, poor porosity and permeability.

825.2 – 827.0 Sandstone, fine, moderately sorted, silty, locally clayey, locally calcareous, laminated and low-amplitude ripple bedded, locally burrowed, poor to fair porosity and permeability.

Core 9: 870.0 – 887.3 ft.

870.0 – 870.3 Claystone, medium gray to olive gray (N5 – 5Y5/0.5), locally silty, slips, massive, firm to hard.

870.3 – 870.8 Siltstone, light medium olive gray (5Y6/0.5), fine silt, clayey, very fine to fine sandy, very poorly sorted, mottled texture, calcareous nodules, tight.

870.8 – 872.3 Mudstone, grades from silty claystone to clayey siltstone, poorly sorted, locally very fine to fine sandy, locally calcareous with cement and diffuse-edged nodules, mottled texture, subfissile near base, hard.

872.3 – 872.8 Limestone, light brownish gray (10YR7.5/0.5), fossiliferous lime mudstone and wackestone with worn rounded fossil fragments up to small pebble size, massive, tight.

872.8 – 873.4 Siltstone, coarse silt, slightly very fine sandy, clayey, poorly sorted, calcareous with common worn fossil fragments and calcite cement, burrowed, poor porosity and permeability to tight.

873.4 – 875.7 Limestone, light brownish gray (10YR7.5/0.5), lime mudstone to fossiliferous wackestone, worn rounded fossil fragments near top and bottom but sparse through middle, gradational basal contact, tight.

875.7 – 877.7 Shale, dark grayish black to black (N2.5 to N1) , carbonaceous, very carbonaceous at top and base, finely laminated, fissile, platy, hard.

877.7 – 877.9	Limestone, medium dark gray (N4), sparsely fossiliferous lime mudstone, tight.
877.9 – 878.0	Shale, dark gray (N3), calcareous, fossiliferous, subfissile, hard.
878.0 – 886.1	Shale, medium gray to medium dark gray (N5 – N4), clay, scattered plant debris, locally burrowed, , subfissile to fissile, increasingly platy near base, hard.
886.1 – 887.2	Shale, dark gray (N4) grading to dark grayish black (N2.5) at base, plant fragments, increasingly carbonaceous toward base, scattered silty laminae, fissile, hard.
887.2 – 887.3	**Mt. Rorah Coal (**from 887.2 to 900.3, excluding partings between 888.3 and 998.8). This part is bony at top grading to banded bright, blocky with well developed cleats, partially broken (base of core).

Core 10: 887.3 – 905.2 ft.

887.3 – 888.3	Coal, bright, moderately well cleated, common pyrite fill in cleat fractures, canister desorption sample taken 887.3–888.3 ft.
888.3 – 894.0	Claystone, medium gray (N5) grading to medium dark gray (N4) at top, locally silty, massive, mottled texture, locally rooted near top, firm to hard but softens when wet.
894.0 – 896.2	Siltstone, fine silt coarsening upward to coarse silt, slightly very fine sandy near top, thin laminations of very fine sandstone from 894.0–895.5, evidence of grain dissolution possibly of small fossil grains, very evenly laminated, graded and intercalated base, poor porosity and permeability.
896.2 – 897.5	Shale, medium gray (N5) grading to dark gray (N3.5) toward base, clay, abundant slips, subfissile, hard.
897.5 – 898.8	Shale, dark grayish black to black (N2 – N1), carbonaceous, locally pyritic with up to 2.5 mm bands and nodules, grades to bony coal at base, fissile, platy.
898.9 – 900.3	Coal, banded dull to locally banded bright, moderately cleated, pyritic, 8 mm pyritic claystone band near base, grades to carbonaceous claystone at base, canister desorption sample taken at 899.2–900.2 ft.
900.3 – 900.6	Claystone, dark gray (N3), carbonaceous with coaly inclusions, rooted, firm to hard but softens when wet.
900.6 – 905.2	Sandstone, very fine to locally fine, muddy, increasingly clayey at top, locally calcareous with included fossil fragments, rooted and burrowed, mottled texture, poor porosity and permeability.

Core 11: 1010.0 – 1029.5 ft.

1010.0 – 1028.9	Claystone, medium dark gray (N4), poorly sorted, varying throughout in silt content from slightly silty to silty, locally micaceous, locally mottled texture 1020.3–1020.6 and 1024.0–1026.2, few slips and dewatering features, subfissile from 1020.6 to 1022.0 and 1022.8 to 1024.0, hard.
1028.9 – 1029.5	Limestone, dark grayish brown (10YR2.5/1), recrystalline lime mudstone, dense, shaly at base, tight.

Appendix 2a: Royal Drilling Hon #9 Well, Proximate/Btu/S Analyses

Coal or shale Sample	Moisture (wt %)	Ash (wt%) as-received	Ash (wt%) Dry	Parr Mineral Matter (wt%, dry)	Volatile Matter (wt%) as-received	Volatile Matter (wt%) dry	Fixed Carbon (wt%) as-received	Fixed Carbon (wt%) dry	Heating value (Btu/lb) as-received	Heating value (Btu/lb) dry	Sulfur (wt%) as-received	Sulfur (wt%) dry	Coal rank*	Moisture&ash of sample splits used in isotherm tests: Equilibrium moisture (wt %)	Moisture&ash of sample splits used in isotherm tests: As-received ash (wt%)
Danville1	7.31	10.27	11.08	14.71	35.48	38.28	46.94	50.64	11815	12747	4.63	5.00	hvBb	9.92	9.80
Danville2	6.95	24.32	26.14	29.89	31.16	33.49	37.57	40.38	9647	10368	2.81	3.02	hvBb	10.10	23.62
Herrin 1	7.10	14.34	15.44	19.67	34.25	36.87	44.30	47.69	11068	11914	5.07	5.46	hvBb	9.44	14.00
Herrin 2	8.66	6.56	7.18	9.11	34.38	37.64	50.40	55.18	12221	13380	2.24	2.45	hvBb	10.03	6.41
Herrin 3	7.76	10.97	11.89	14.54	33.91	36.76	47.36	51.34	11592	12567	2.84	3.08	hvBb	9.51	10.91
Springfield 1	6.06	10.58	11.26	13.82	35.28	37.56	48.08	51.18	12080	12859	2.83	3.01	hvBb	8.50	10.55
Springfield 2	6.65	7.43	7.96	9.88	37.24	39.89	48.68	52.15	12384	13266	2.18	2.34	hvBb	9.77	7.10
Springfield 3	6.72	10.57	11.33	13.15	34.75	37.25	47.96	51.42	12017	12883	1.54	1.65	hvBb	7.77	10.99
Houchin Creek	4.91	9.57	10.06	14.61	40.02	42.09	45.50	47.85	12087	12711	6.46	6.79	hvBb	12.73	8.54
Survant 1	5.67	9.17	9.72	13.58	37.88	40.16	47.28	50.12	12050	12774	5.28	5.60	hvBb	8.78	8.92
Survant 2	5.35	9.54	10.08	13.16	38.70	40.89	46.41	49.03	12477	13182	3.91	4.13	hvAb	9.96	8.90
Survant 3	5.22	9.18	9.69	11.90	38.64	40.77	46.96	49.55	12544	13235	2.48	2.62	hvBb	7.78	8.78
Dekoven	4.51	25.24	26.43	30.19	33.91	35.51	36.34	38.06	10187	10668	2.85	2.98	hvAb	8.11	23.87
Davis 1	4.47	17.34	18.15	26.18	35.42	37.08	42.77	44.77	10977	11491	11.43	11.96	hvBb	10.60	16.66
Davis 2	5.05	10.09	10.63	14.29	39.40	41.50	45.46	47.88	12277	12930	4.86	5.12	hvBb	7.66	9.44
Davis 3	4.73	11.45	12.02	16.95	37.58	39.45	46.24	48.54	11877	12467	6.88	7.22	hvBb	7.67	10.64
Turner Mine Sh	2.25	66.47	68.00	74.79	19.79	20.25	11.49	11.75	4302	4401	2.40	2.46	hvAb	5.05	66.05
Excello Sh	2.70	71.93	73.93	81.46	15.20	15.62	10.17	10.45	3360	3453	2.86	2.94	hvAb	5.60	70.00
MeccaQuary Sh	3.48	81.50	84.44	93.85	13.81	14.31	1.21	1.25	1137	1178	4.67	4.84	N/A	6.32	78.89

*Rank was based on Parr formulas (ASTM D388)(a).

Appendix 2b: Craig Howard, Wasem #C-1 Well, Proximate/Btu/S Analyses

Coal or shale Sample	Moisture (wt %)	Ash (wt%) as-received	Ash (wt%) dry	Parr Mineral Matter (wt%, dry)	Volatile Matter (wt%) as-received	Volatile Matter (wt%) dry	Fixed Carbon (wt%) as-received	Fixed Carbon (wt%) dry	Heating value (Btu/lb) as-received	Heating value (Btu/lb) Dry	Sulfur (wt%) as-received	Sulfur (wt%) dry	Coal rank*	Moisture&ash of sample splits used in isotherm tests: Equilibrium moisture (wt %)	Moisture&ash of sample splits used in isotherm tests: As-received ash (wt%)
Danville1	9.04	11.90	12.19	15.12	35.16	38.65	44.71	49.15	11531	12677	3.23	3.55	hvBb	8.31	11.33
Danville2	8.49	12.16	13.29	17.90	34.72	37.94	44.63	48.77	11472	12536	5.90	6.45	hvBb	8.25	11.90
Herrin 1	8.80	6.27	6.88	9.14	37.00	40.57	47.93	52.55	12366	13559	2.84	3.11	hvBb	8.36	5.60
Herrin 2	9.30	6.81	7.51	10.05	34.42	37.95	49.47	54.54	12047	13282	3.19	3.52	hvBb	8.05	7.78
Herrin 3	8.99	11.10	12.20	16.61	33.93	37.28	45.98	50.52	11401	12527	5.69	6.25	hvBb	8.79	10.43
Springfield 1	7.12	15.24	16.41	19.73	34.70	37.36	42.94	46.23	11203	12062	3.39	3.65	hvBb	6.45	14.87
Springfield 2	8.34	7.67	8.37	10.38	37.46	40.87	46.53	50.76	12394	13522	2.23	2.43	hvBb	7.27	7.27
Springfield 3	6.88	10.17	10.92	14.24	36.88	39.60	46.07	49.47	11887	12765	4.13	4.44	hvBb	6.66	10.83
Houchin Creek	7.90	6.93	7.52	9.65	37.41	40.62	47.76	51.86	12358	13418	2.56	2.78	hvBb	6.88	6.88
Survant	6.81	11.38	12.21	16.42	38.27	41.07	43.54	46.72	11704	12559	5.47	5.87	hvBb	6.83	10.87
Davis 1	5.71	11.13	11.70	16.33	38.71	41.05	44.55	47.25	11947	12670	6.33	6.71	hvBb	6.32	11.74
Davis 2	8.32	5.97	6.51	8.58	37.07	40.43	48.64	53.05	12554	13693	2.58	2.81	hvBb	6.68	6.19
Davis 3	7.49	8.99	9.72	11.66	35.90	38.81	47.62	51.48	12305	13301	1.96	2.12	hvBb	6.44	8.73
Mt Rorah 1	6.73	14.05	15.06	19.40	34.33	36.81	44.89	48.13	11520	12351	5.32	5.70	hvBb	6.66	14.23
Mt Rorah 2	6.50	13.45	14.39	19.83	35.02	37.45	45.03	48.16	11593	12399	7.29	7.80	hvBb	6.28	13.32
Excello Sh	4.65	66.68	69.93	77.05	16.77	17.59	11.90	12.48	3975	4169	2.64	2.77	N/A	4.61	66.79
MeccaQuary Sh	3.67	77.64	80.60	88.90	13.13	13.63	5.56	5.77	1958	2033	3.25	3.37	N/A	3.80	76.05

*Rank was based on Parr formulas (ASTM D388)(a).

Appendix 2c: Peabody Ameren#1-24 Well, Proximate/Btu/S Analyses

Coal or shale sample	Moisture (wt %)	Ash (wt%)		Parr Mineral Matter	Volatile Matter (wt%)		Fixed Carbon (wt%)		Heating value (Btu/lb)		Sulfur (wt%)		Coal rank*	Moisture&ash of sample splits used in isotherm tests	
		as-received	dry	(wt%, dry)	as-received	dry	as-received	dry	As-received	Dry	as-received	dry		Equilibrium moisture (wt %)	As-received ash (wt%)
Danville1	8.13	13.99	15.23	18.54	32.74	35.64	45.14	49.13	11464	12479	3.49	3.80	hvBb	7.69	13.69
Danville2	8.69	13.21	14.47	17.55	34.21	34.74	43.89	48.07	11961	13099	3.19	3.49	hvAb	8.06	13.58
Jamestown 1	7.50	18.75	20.27	24.54	32.91	35.58	40.84	44.15	10913	11798	4.45	4.81	hvAb	6.69	18.84
Jamestown 2	6.54	28.26	30.24	35.02	27.87	29.82	37.33	39.94	9489	10153	4.02	4.30	hvAb	6.07	24.69
Herrin 1	8.26	19.84	21.63	24.61	29.71	32.39	42.19	45.99	10402	11339	2.08	2.27	hvBb	7.49	20.16
Herrin 2	8.70	6.09	6.67	8.60	35.26	38.62	49.95	54.71	12386	13566	2.31	2.53	hvBb	7.91	6.27
Herrin 3	8.51	11.17	12.21	16.15	33.24	36.33	47.08	51.46	11796	12893	4.93	5.39	hvBb	8.05	11.25
Briar Hill	7.51	13.97	15.10	18.51	34.37	37.16	44.15	47.73	12013	12988	3.70	4.00	hvAb	6.84	13.80
Springfield	8.76	41.68	45.68	51.59	24.46	26.81	25.10	27.51	7220	7913	3.75	4.11	hvAb	9.11	40.58
Houchin Creek	4.84	29.38	30.87	42.27	32.73	34.39	33.05	34.73	9090	9552	15.45	16.24	hvAb	5.63	28.07
Survant	7.63	9.00	9.74	10.94	35.05	37.95	48.32	52.31	12419	13445	0.70	0.76	hvBb	9.07	8.69
Upper Dekoven	6.36	19.24	20.55	23.56	34.63	36.98	39.77	42.47	11100	11854	2.33	2.49	hvAb	5.62	19.11
Lower Dekoven	3.96	50.51	52.59	59.58	22.91	23.85	22.62	23.55	5826	6066	4.86	5.06	hvBb	3.85	49.98
Seelyville 1	6.21	13.29	14.17	17.94	35.82	38.19	44.68	47.64	11883	11276	4.50	4.80	hvAb	5.74	12.90
Seelyville 2	5.70	15.63	16.57	21.20	34.91	37.02	43.76	46.41	11276	11958	5.67	6.01	hvAb	5.50	15.94
Seelyville 3	6.27	10.53	11.23	15.43	36.56	39.01	46.64	49.76	12203	13019	5.63	6.01	hvAb	6.43	10.01
Anna Sh	4.78	76.51	80.35	88.14	11.11	11.67	7.60	7.98	1997	2097	2.35	2.47	N/A	N/A	N/A
Shale X	4.6	83.24	87.25	96.64	9.91	10.39	2.25	2.36	896	939	4.19	4.39	N/A	N/A	N/A
Excello Sh	4.15	65.62	68.46	75.15	17.04	17.78	13.19	13.76	4173	4354	2.11	2.2	N/A	N/A	N/A
Shale Y	3.75	66.53	69.12	76.41	16.18	16.81	13.54	14.07	3962	4166	3.08	3.2	N/A	N/A	N/A

*Rank was based on Parr formulas (ASTM D388)(a)

Appendix 3: Langmuir Isotherms and methane saturation of coals from three ISGS test wells.

(Analyses by TerraTek, Salt Lake City, UT)

Appendix 3a Jim Cantrell, Hon #9, White County, Illinois

	As-Received		Dry		DAF		Temperature	Sat'n
Sample	P_L	V_L	P_L	V_L	P_L	V_L	(deg. F)	(%)
Danville 1	865.5	460.8	865.5	571.6	865.5	574	69	60.9
Danville 2	740.9	314.5	740.9	349.8	740.9	474.4	69	67.9
Herrin 1	779.8	392.8	779.8	433.7	779.8	513	70	56.0
Herrin 2	786.4	437.7	786.4	486.5	786.4	523.8	70	57.5
Herrin 3	781.8	411.7	781.8	454.9	781.8	517.3	70	53.8
Turner Mine Shale	871.7	178.4	871.7	187.9	871.7	617.4	71	52.0
Springfield 1	764.1	425.6	764.1	465.2	764.1	465.2	70	44.8
Springfield 2	795.6	422.3	795.6	468	795.6	508	70	52.2
Springfield 3	739.6	422.9	739.6	458.6	739.6	510	70	46.9
Excello Shale	887.3	135.2	887.3	143.2	887.3	553.9	72	71.2
Houchin Creek	583.2	296.1	583.2	339.3	583.2	376.1	72	56.4
Survant 1	526.8	327.2	526.8	358.6	526.8	397.5	73	53.6
Survant 2	621.2	339.2	621.2	376.8	621.2	418.1	73	54.1
Survant 3	594	320.2	594	347.2	594	383.7	73	54.1
MQ Shale	634.7	27.7	634.7	29.6	634.7	187.4	74	184.6
Dekoven	507	273.8	507	298	507	402.6	74	50.3
Davis 1	486.7	312.7	486.7	349.8	486.7	329.8	75	60.2
Davis 2	496.7	401.9	496.7	435.3	496.7	484.8	75	47.2
Davis 3	518.6	323.3	518.6	350.1	518.6	395.7	75	46.5

Appendix 3b Howard Energy, #C-1 Wasem, White Co, IL

Sample	As-Received		Dry		DAF		Temperature	Sat'n
	P_L	V_L	P_L	V_L	P_L	V_L	(deg. F)	(%)
Danville 1	480.4	384.7	480.4	419.5	480.4	478.7	63	91.3
Danville 2	494.5	351.9	494.5	383.5	494.5	440.6	63	92.8
Herrin 1	478.1	415.2	478.1	453	478.1	482.5	64	73.3
Herrin 2	473.9	375.7	473.9	408.5	473.9	446.3	64	82.5
Herrin 3	470.5	356.5	470.5	390.9	470.5	441.3	64	86.4
Springfield 1	532.8	326	532.8	348.5	532.8	414.4	65	66.8
Springfield 2	530.2	386.1	530.2	416.4	530.2	450.3	65	60.1
Springfield 3	585.2	350.8	585.2	375.9	585.2	425.2	65	68.8
Houchin Creek	491.9	392.3	491.9	425.2	491.9	459.4	66	50.6
Survant	535	379.5	535	407.4	535	461.2	66	60.4
Davis 1	544.3	395.4	544.3	422.1	544.3	482.6	70	39.5
Davis 2	543.1	421.1	543.1	451.2	543.1	483.3	70	44.6
Davis 3	531.7	416.7	531.7	445.3	531.7	491.2	70	42.2
Mt. Rorah 1	529.2	301.8	529.2	323.4	529.2	381.6	71	25.5
Mt. Rorah 2	510.4	320.8	510.4	342.3	510.4	399	71	24.4
Excello Shale	532	146	532	153.1	532	513.9	66	76.2
MQ Shale	533.1	75.8	533.1	78.8	533.1	376.1	68	88.1

Appendix 3c Peabody, #1-24 Ameren Jasper Co., IL

Coal	Depth	As-Received		Dry		DMMF		Temperature	Sat'n
	FT	P_L	V_L	P_L	V_L	P_L	V_L	(deg. F)	(%)
Danville 1	1188	610.8	368.1	610.8	398.8	610.8	468.2	78	46.5
Danville 2	1189	579.5	349.7	579.5	380.3	579.5	446.2	78	49.6
Jamestown 1	1216	587.5	341.1	587.5	365.9	587.5	456.5	78	56.5
Jamestown 2	1217	570.2	284.4	570.2	302.8	570.2	441.1	78	62.5
Herrin 2	1227	492.8	377.4	492.8	409.8	492.8	439.7	78	49.5
Herrin 1	1230	513.6	321.9	513.6	348	513.6	444.9	78	53.8
Herrin 3	1231	538.9	360.9	538.9	392.5	538.9	447.3	78	53.0
Briar Hill	1259	561.6	326.5	561.6	350.5	561.6	411.4	79	47.7
Springfield	1269	551.1	231.8	551.1	255	551.1	460.8	79	64.4
Houchin Creek	1349	634.9	238.4	634.9	252.6	634.9	359.6	81	60.8
Survant	1424	540.3	407.9	540.3	448.6	540.3	496	82	48.4
Upper Dekoven	1486	563.2	328.2	563.2	347.8	563.2	436.1	83	51.1
Lower Dekoven	1491	606.3	203.6	606.3	211.8	606.3	441	83	49.7
Seeleyville 1	1497	542.8	389	542.8	412.6	542.8	478.1	83	51.7
Seeleyville 2	1498	498.1	329.6	498.1	348.7	498.1	419.5	83	58.6
Seeleyville 3	1500	509.6	382.7	509.6	409	509.6	458	84	62.1

Appendix 4: Summaries of gas content and other data on individual coal and shale samples from three ISGS test wells

Well:	Hon #9
Operator:	Royal Drilling Co
Location:	White County
Field:	0
Formation:	Pennsylvanian, Herrin Coal
Comments:	Coal seam is 803 ft deep and 5.3 ft thick

Basic Information

Sample ID	Canister Number	Driller's Depth (feet)	As-Received Sample Weight (g)	DAF Sample Weight (g)	DMMF Sample Weight (g)	Measured Desorption (scm^3)	Sorption Time (hr) for 63.2% of Measured Desorption
Hon-Herrin 1	D3	803.5	1779	1362	1292	2918.1	888.4

Sorption Time (hr) for 63.2% of Total Gas
2260.1

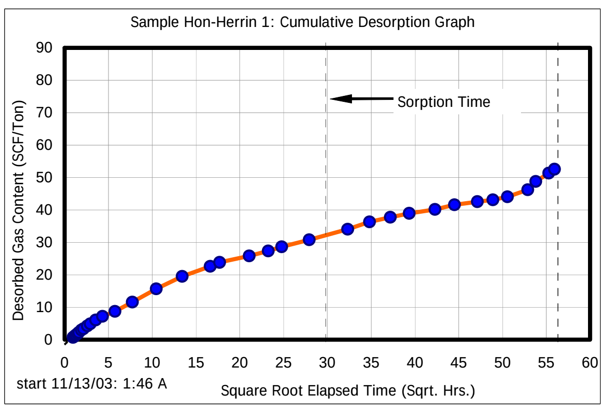
Lost Gas Volume

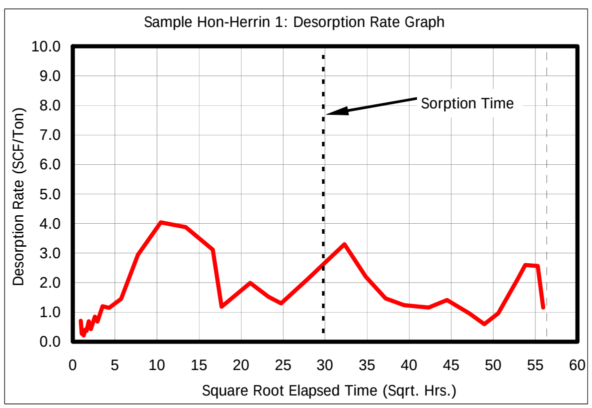
USBM			Smith and Williams	
(%)	(As-Received) (scf/ton)	(DMMF) (scf/ton)	(%)	(As-Received) (scf/ton)
2.8	1.5	2.1	1.7	0.9

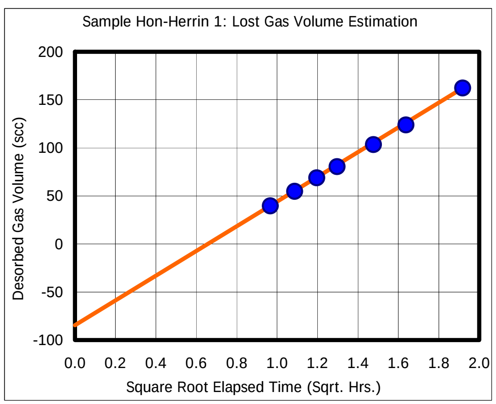
Total Gas Volume

USBM			Smith and Williams		
(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)	(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)
64.4	84.1	88.6	63.8	83.3	87.8

Other Components					Residual Gas Volume		
Sulfur (wt%)	Moisture (wt%)	Ash (wt%)	Moisture Plus Ash (wt%)	Sulfur, Moisture and Ash (wt%)	[As-Received] (scf/ton)	[DAF] (scf/ton)	[DMMF] (scf/ton)
5.07	9.44	14.00	23.44	27.35	10.32	13.48	14.20







Well:	Hon #9
Operator:	Royal Drilling Co
Location:	White County
Field:	0
Formation:	Pennsylvanian, Herrin Coal
Comments:	Coal seam is 803 ft deep and 5.3 ft thick

Basic Information

Sample ID	Canister Number	Driller's Depth (feet)	As-Received Sample Weight (g)	DAF Sample Weight (g)	DMMF Sample Weight (g)	Measured Desorption (scm^3)	Sorption Time (hr) for 63.2% of Measured Desorption
Hon-Herrin 2	D4	805	1645	1375	1346	3164.8	607.5

Sorption Time (hr) for 63.2% of Total Gas
2456.3

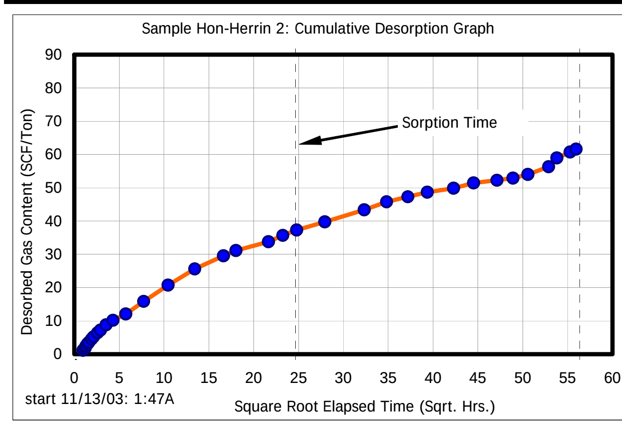
Lost Gas Volume

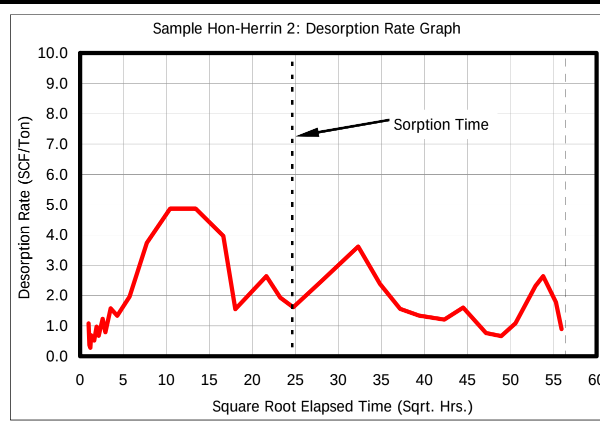
USBM			Smith and Williams	
(%)	(As-Received) (scf/ton)	(DMMF) (scf/ton)	(%)	(As-Received) (scf/ton)
4.1	2.7	3.3	2.1	1.3

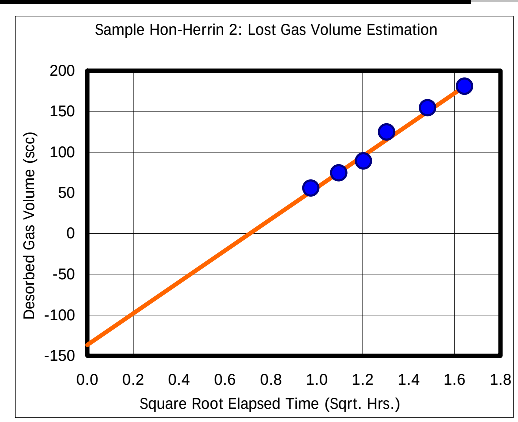
Total Gas Volume

USBM			Smith and Williams		
(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)	(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)
75.7	90.6	92.5	74.4	89.0	90.9

Other Components					Residual Gas Volume		
Sulfur (wt%)	Moisture (wt%)	Ash (wt%)	Moisture Plus Ash (wt%)	Sulfur, Moisture and Ash (wt%)	[As-Received] (scf/ton)	[DAF] (scf/ton)	[DMMF] (scf/ton)
2.24	10.03	6.41	16.44	18.18	11.41	13.65	13.95







Well:	Hon #9
Operator:	Royal Drilling Co
Location:	White County
Field:	0
Formation:	Pennsylvanian, Herrin Coal
Comments:	Coal seam is 803 ft deep and 5.3 ft thick

Basic Information

Sample ID	Canister Number	Driller's Depth (feet)	As-Received Sample Weight (g)	DAF Sample Weight (g)	DMMF Sample Weight (g)	Measured Desorption (scm^3)	Sorption Time (hr) for 63.2% of Measured Desorption
Hon-Herrin 3	D5	807	1895	1508	1462	3167.9	758.1

Sorption Time (hr) for 63.2% of Total Gas
2476.7

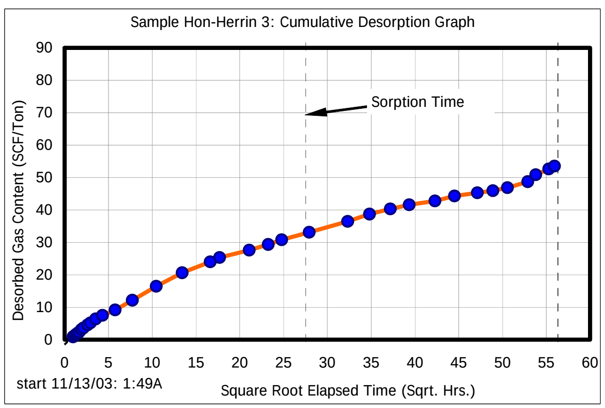
Lost Gas Volume

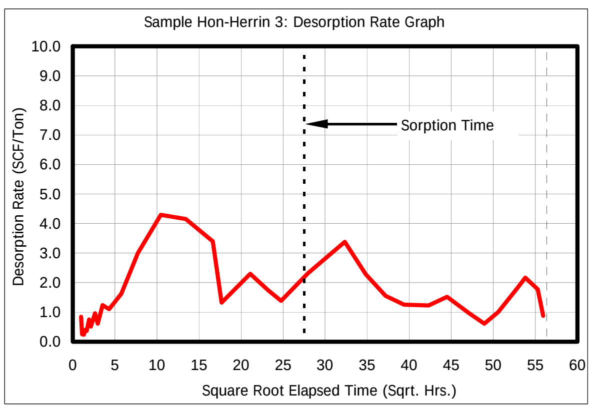
USBM			Smith and Williams	
(%)	(As-Received) (scf/ton)	(DMMF) (scf/ton)	(%)	(As-Received) (scf/ton)
2.8	1.5	2.0	1.9	1.0

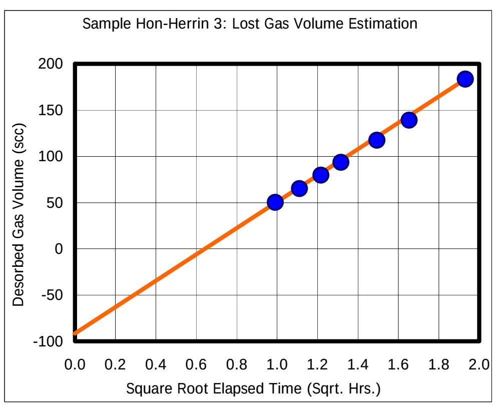
Total Gas Volume

USBM			Smith and Williams		
(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)	(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)
66.3	83.4	86.0	65.8	82.7	85.3

Other Components					Residual Gas Volume		
Sulfur (wt%)	Moisture (wt%)	Ash (wt%)	Moisture Plus Ash (wt%)	Sulfur, Moisture and Ash (wt%)	[As-Received] (scf/ton)	[DAF] (scf/ton)	[DMMF] (scf/ton)
2.84	9.51	10.91	20.42	22.85	11.24	14.12	14.57







Well:	Hon #9
Operator:	Royal Drilling Co
Location:	White County
Field:	0
Formation:	Pennsylvanian, Turner Mine Shale
Comments:	Shale is 873 ft deep and 7.3 ft thick

Basic Information

Sample ID	Canister Number	Driller's Depth (feet)	As-Received Sample Weight (g)	DAF Sample Weight (g)	DMMF Sample Weight (g)	Measured Desorption (scm^3)	Sorption Time (hr) for 63.2% of Measured Desorption
Hon-Turner Mine Shale	E1	874	1958	566	437	1098.7	1204.1

Sorption Time (hr) for 63.2% of Total Gas
2223.0

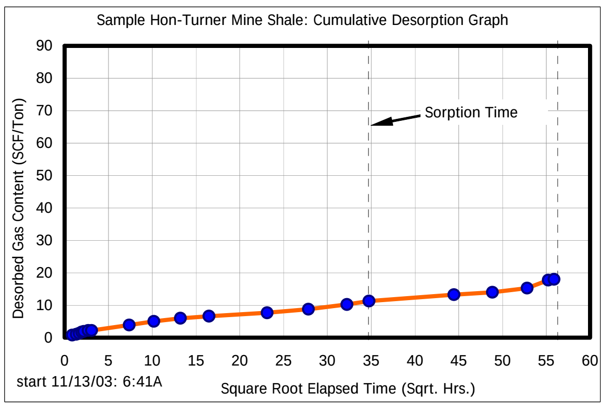
Lost Gas Volume

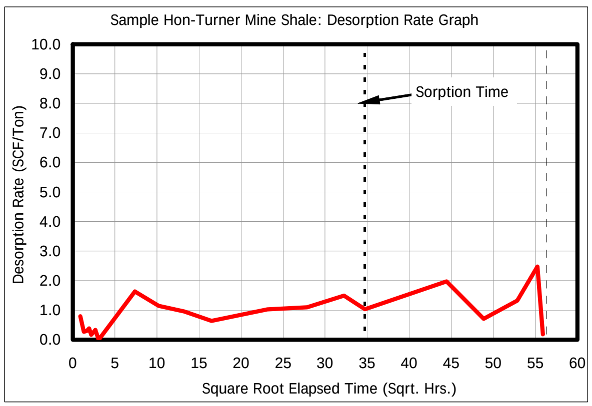
USBM			Smith and Williams	
(%)	(As-Received) (scf/ton)	(DMMF) (scf/ton)	(%)	(As-Received) (scf/ton)
0.4	0.1	0.3	1.4	0.2

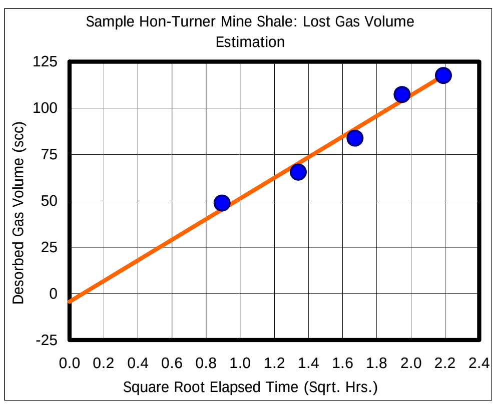
Total Gas Volume

USBM			Smith and Williams		
(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)	(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)
21.7	75.0	97.2	21.8	75.6	98.0

Other Components					Residual Gas Volume		
Sulfur (wt%)	Moisture (wt%)	Ash (wt%)	Moisture Plus Ash (wt%)	Sulfur, Moisture and Ash (wt%)	[As-Received] (scf/ton)	[DAF] (scf/ton)	[DMMF] (scf/ton)
2.40	5.05	66.05	71.10	77.70	3.62	12.53	16.24







Well:	Hon #9
Operator:	Royal Drilling Co
Location:	White County
Field:	0
Formation:	Pennsylvanian, Springfield Coal
Comments:	Coal seam is 880 ft deep and 4.4 ft thick

Basic Information

Sample ID	Canister Number	Driller's Depth (feet)	As-Received Sample Weight (g)	DAF Sample Weight (g)	DMMF Sample Weight (g)	Measured Desorption (scm^3)	Sorption Time (hr) for 63.2% of Measured Desorption
Hon-Springfield 1	E2	880.8	1835	1485	1441	2540.0	881.8

Sorption Time (hr) for 63.2% of Total Gas
2680.8

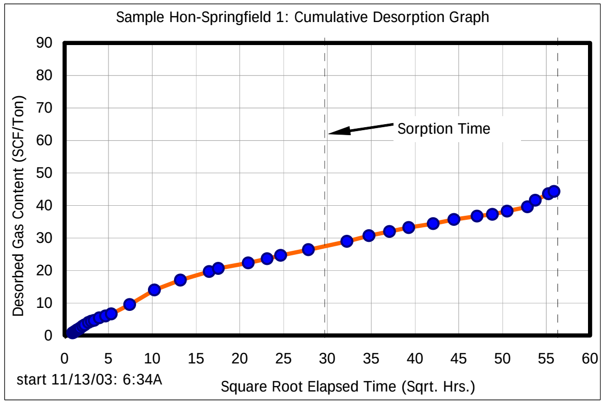
Lost Gas Volume

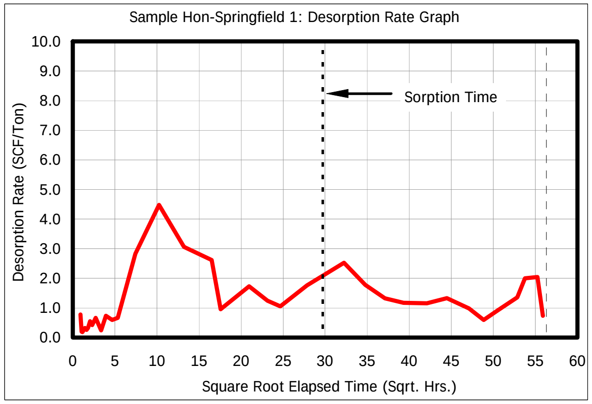
USBM			Smith and Williams	
(%)	(As-Received) (scf/ton)	(DMMF) (scf/ton)	(%)	(As-Received) (scf/ton)
1.9	0.8	1.1	1.6	0.7

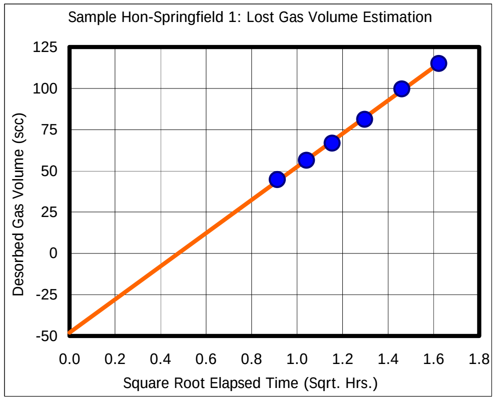
Total Gas Volume

USBM			Smith and Williams		
(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)	(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)
61.6	76.0	78.4	61.4	75.9	78.2

Other Components					Residual Gas Volume		
Sulfur (wt%)	Moisture (wt%)	Ash (wt%)	Moisture Plus Ash (wt%)	Sulfur, Moisture and Ash (wt%)	[As-Received] (scf/ton)	[DAF] (scf/ton)	[DMMF] (scf/ton)
2.83	8.50	10.55	19.05	21.45	16.38	20.23	20.85







Well:	Hon #9
Operator:	Royal Drilling Co
Location:	White County
Field:	0
Formation:	Pennsylvanian, Springfield Coal
Comments:	Coal seam is 880 ft deep and 4.4 ft thick

Basic Information

Sample ID	Canister Number	Driller's Depth (feet)	As-Received Sample Weight (g)	DAF Sample Weight (g)	DMMF Sample Weight (g)	Measured Desorption (scm^3)	Sorption Time (hr) for 63.2% of Measured Desorption
Hon-Springfield 2	E3	882.7	1734	1441	1411	3036.4	656.0

Sorption Time (hr) for 63.2% of Total Gas
1561.5

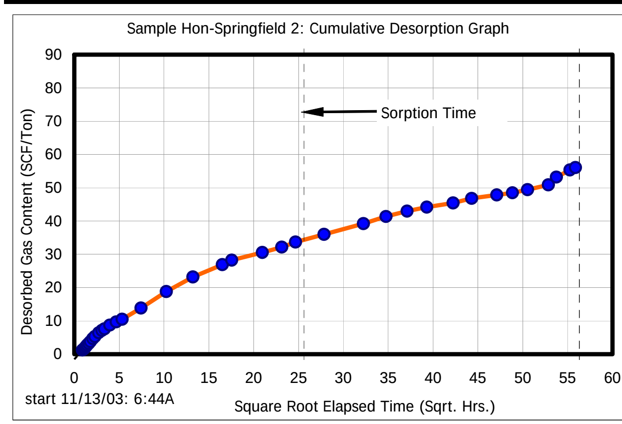
Lost Gas Volume

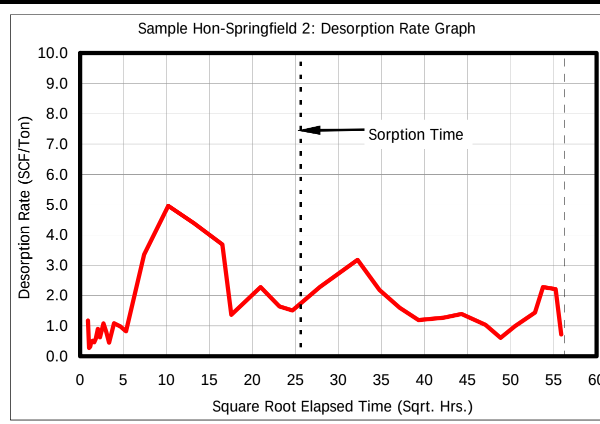
USBM			Smith and Williams	
(%)	(As-Received) (scf/ton)	(DMMF) (scf/ton)	(%)	(As-Received) (scf/ton)
2.7	1.6	1.9	2.0	1.1

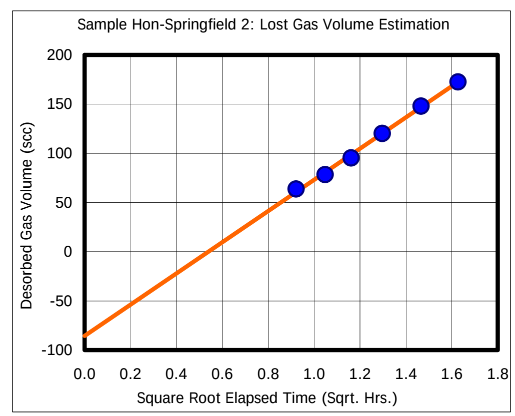
Total Gas Volume

USBM			Smith and Williams		
(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)	(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)
70.0	84.3	86.1	69.6	83.7	85.5

Other Components					Residual Gas Volume		
Sulfur (wt%)	Moisture (wt%)	Ash (wt%)	Moisture Plus Ash (wt%)	Sulfur, Moisture and Ash (wt%)	[As-Received] (scf/ton)	[DAF] (scf/ton)	[DMMF] (scf/ton)
2.18	9.77	7.10	16.87	18.64	12.36	14.87	15.19







Well:	Hon #9
Operator:	Royal Drilling Co
Location:	White County
Field:	0
Formation:	Pennsylvanian, Springfield Coal
Comments:	Coal seam is 880 ft deep and 4.4 ft thick

Basic Information

Sample ID	Canister Number	Driller's Depth (feet)	As-Received Sample Weight (g)	DAF Sample Weight (g)	DMMF Sample Weight (g)	Measured Desorption (scm^3)	Sorption Time (hr) for 63.2% of Measured Desorption
Hon-Springfield 3	E4	883.7	1494	1214	1188	2431.9	706.3

Sorption Time (hr) for 63.2% of Total Gas
1845.7

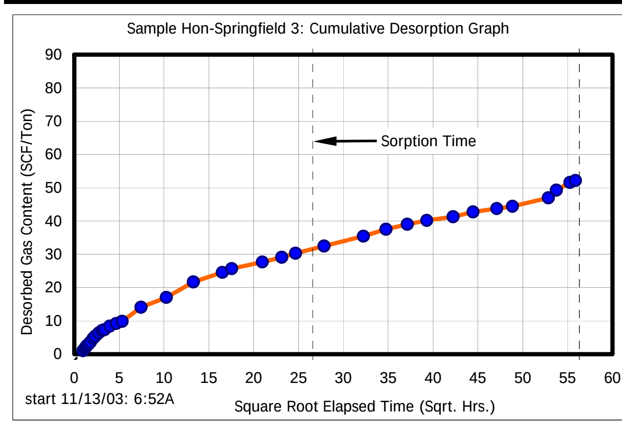
Lost Gas Volume

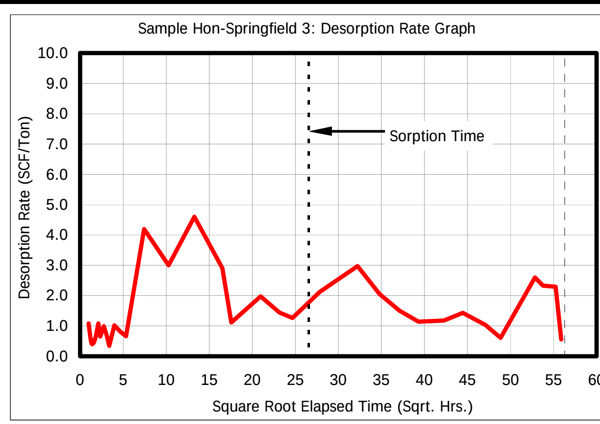
USBM			Smith and Williams	
(%)	(As-Received) (scf/ton)	(DMMF) (scf/ton)	(%)	(As-Received) (scf/ton)
3.7	2.0	2.5	2.2	1.2

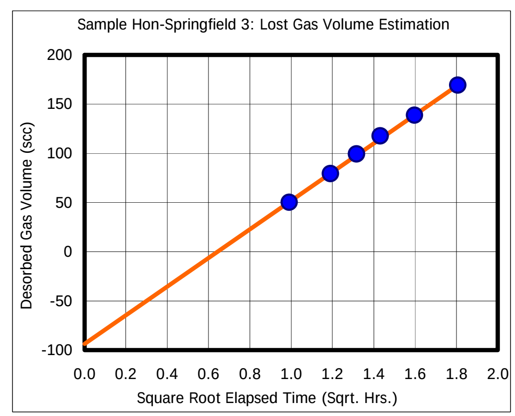
Total Gas Volume

USBM			Smith and Williams		
(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)	(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)
66.1	81.4	83.2	65.3	80.4	82.1

Other Components					Residual Gas Volume		
Sulfur (wt%)	Moisture (wt%)	Ash (wt%)	Moisture Plus Ash (wt%)	Sulfur, Moisture and Ash (wt%)	[As-Received] (scf/ton)	[DAF] (scf/ton)	[DMMF] (scf/ton)
1.54	7.77	10.99	18.76	20.49	11.98	14.75	15.07







Well:	Hon #9
Operator:	Royal Drilling Co
Location:	White County
Field:	0
Formation:	Pennsylvanian, Excello Shale
Comments:	Shale is 960 ft deep and 7.1 ft thick

Basic Information

Sample ID	Canister Number	Driller's Depth (feet)	As-Received Sample Weight (g)	DAF Sample Weight (g)	DMMF Sample Weight (g)	Measured Desorption (scm^3)	Sorption Time (hr) for 63.2% of Measured Desorption
Hon-Excello Shale	E5	967.4	2464	601	424	1555.1	678.2

Sorption Time (hr) for 63.2% of Total Gas
904.3

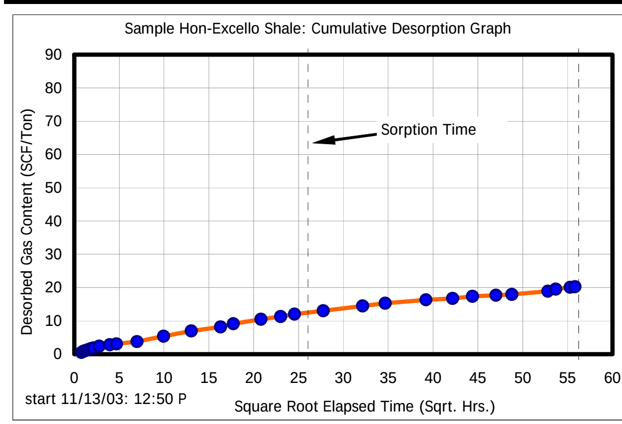
Lost Gas Volume

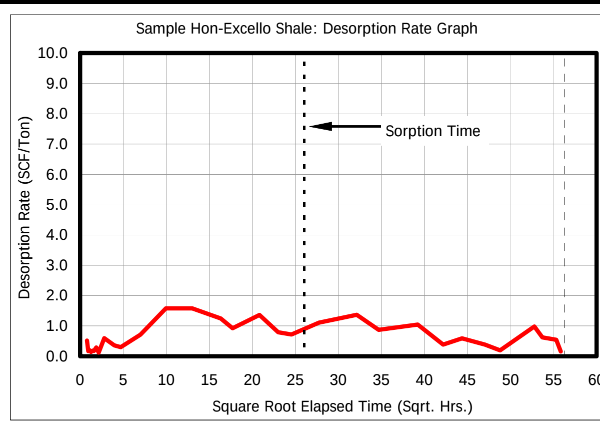
USBM			Smith and Williams	
(%)	(As-Received) (scf/ton)	(DMMF) (scf/ton)	(%)	(As-Received) (scf/ton)
2.1	0.4	2.5	1.0	0.2

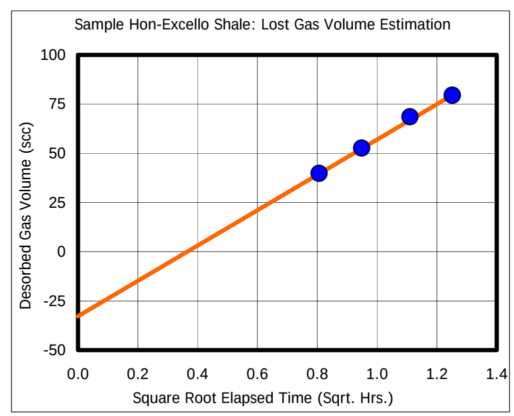
Total Gas Volume

USBM			Smith and Williams		
(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)	(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)
21.8	89.2	126.4	21.6	88.4	125.2

Other Components					Residual Gas Volume		
Sulfur (wt%)	Moisture (wt%)	Ash (wt%)	Moisture Plus Ash (wt%)	Sulfur, Moisture and Ash (wt%)	[As-Received] (scf/ton)	[DAF] (scf/ton)	[DMMF] (scf/ton)
2.86	5.60	70.00	75.60	82.77	1.13	4.63	6.56







Well:	Hon #9
Operator:	Royal Drilling Co
Location:	White County
Field:	0
Formation:	Pennsylvanian, Houchin Creek Coal
Comments:	Coal is 967 ft deep and 2.6 ft thick

Basic Information

Sample ID	Canister Number	Driller's Depth (feet)	As-Received Sample Weight (g)	DAF Sample Weight (g)	DMMF Sample Weight (g)	Measured Desorption (scm^3)	Sorption Time (hr) for 63.2% of Measured Desorption
Hon-Houchin Creek	C2	968.7	1884	1483	1403	2558.7	961.1

Sorption Time (hr) for 63.2% of Total Gas
2978.4

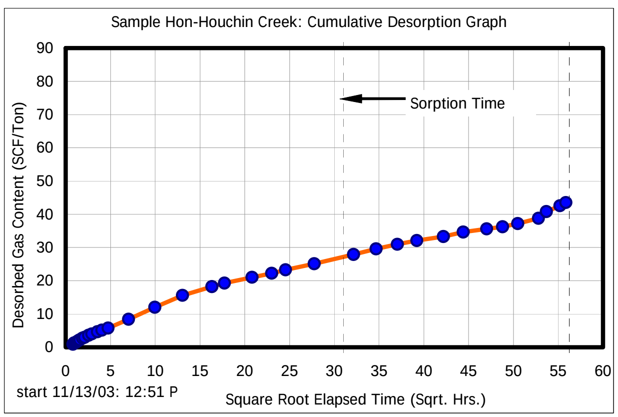
Lost Gas Volume

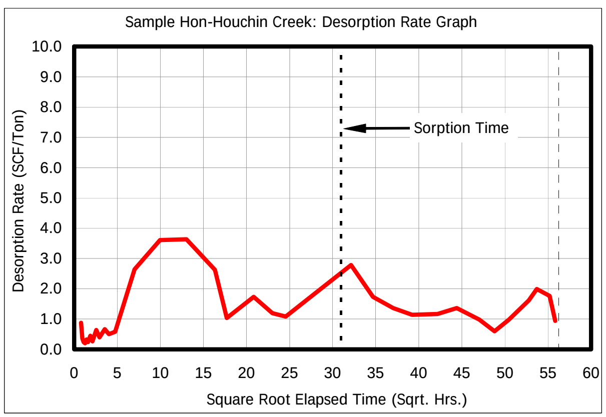
USBM			Smith and Williams	
(%)	(As-Received) (scf/ton)	(DMMF) (scf/ton)	(%)	(As-Received) (scf/ton)
1.0	0.5	0.6	1.1	0.5

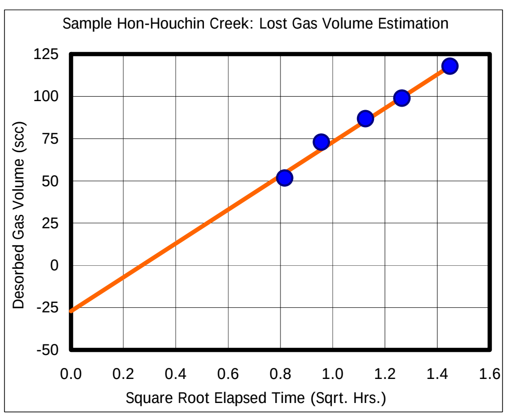
Total Gas Volume

USBM			Smith and Williams		
(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)	(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)
66.2	84.1	88.8	66.2	84.1	88.9

Other Components					Residual Gas Volume		
Sulfur (wt%)	Moisture (wt%)	Ash (wt%)	Moisture Plus Ash (wt%)	Sulfur, Moisture and Ash (wt%)	[As-Received] (scf/ton)	[DAF] (scf/ton)	[DMMF] (scf/ton)
6.46	12.73	8.54	21.27	25.51	22.21	28.21	29.81







Well:	Hon #9
Operator:	Royal Drilling Co
Location:	White County
Field:	0
Formation:	Pennsylvanian, Survant Coal
Comments:	Coal seam is 993 ft deep and 3.7 ft thick

Basic Information

Sample ID	Canister Number	Driller's Depth (feet)	As-Received Sample Weight (g)	DAF Sample Weight (g)	DMMF Sample Weight (g)	Measured Desorption (scm^3)	Sorption Time (hr) for 63.2% of Measured Desorption
Hon-Survant 1	C3	993.9	1789	1472	1408	3263.6	739.7

Sorption Time (hr) for 63.2% of Total Gas
1894.0

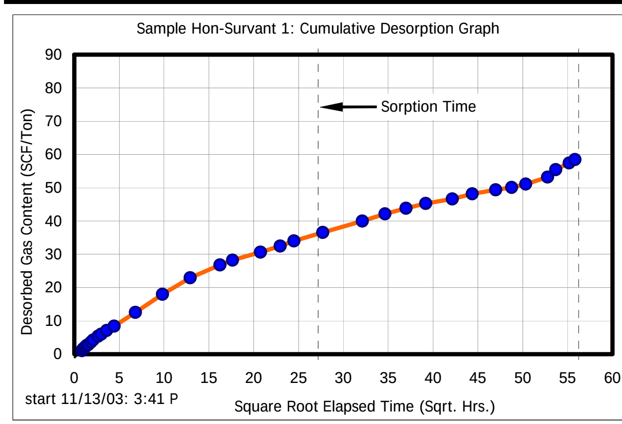
Lost Gas Volume

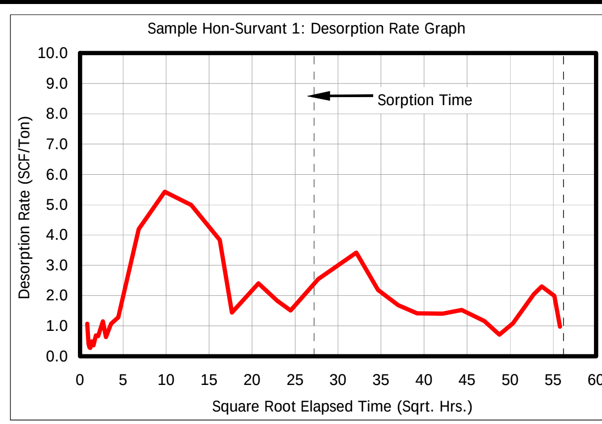
USBM			Smith and Williams	
(%)	(As-Received) (scf/ton)	(DMMF) (scf/ton)	(%)	(As-Received) (scf/ton)
1.9	1.1	1.4	1.5	0.9

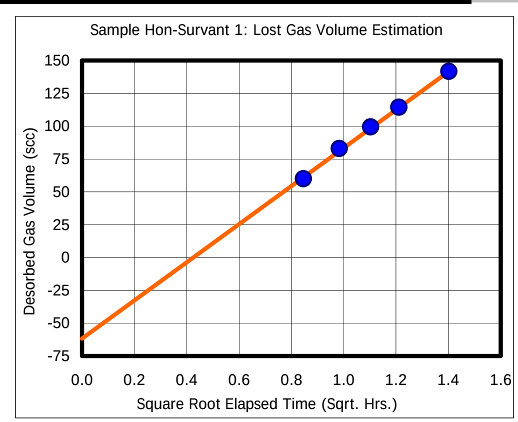
Total Gas Volume

USBM			Smith and Williams		
(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)	(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)
75.3	91.5	95.8	75.2	91.3	95.5

Other Components					Residual Gas Volume		
Sulfur (wt%)	Moisture (wt%)	Ash (wt%)	Moisture Plus Ash (wt%)	Sulfur, Moisture and Ash (wt%)	[As-Received] (scf/ton)	[DAF] (scf/ton)	[DMMF] (scf/ton)
5.28	8.78	8.92	17.70	21.32	15.79	19.19	20.07







Well:	Hon #9
Operator:	Royal Drilling Co
Location:	White County
Field:	0
Formation:	Pennsylvanian, Survant Coal
Comments:	Coal seam is 993 ft deep and 3.7 ft thick

Basic Information

Sample ID	Canister Number	Driller's Depth (feet)	As-Received Sample Weight (g)	DAF Sample Weight (g)	DMMF Sample Weight (g)	Measured Desorption (scm^3)	Sorption Time (hr) for 63.2% of Measured Desorption
Hon-Survant 2	C4	994.9	1640	1331	1284	3038.4	792.0

Sorption Time (hr) for 63.2% of Total Gas
1532.8

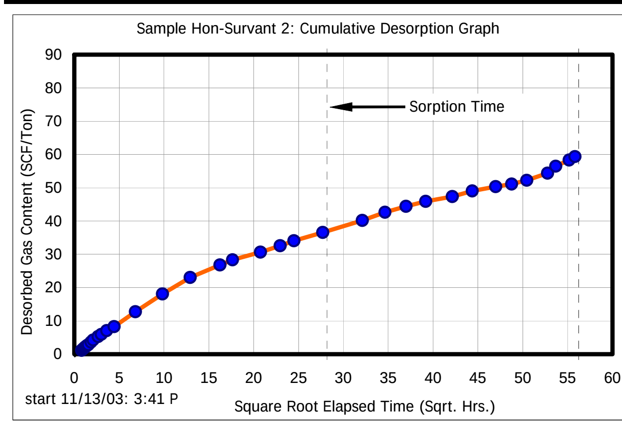
Lost Gas Volume

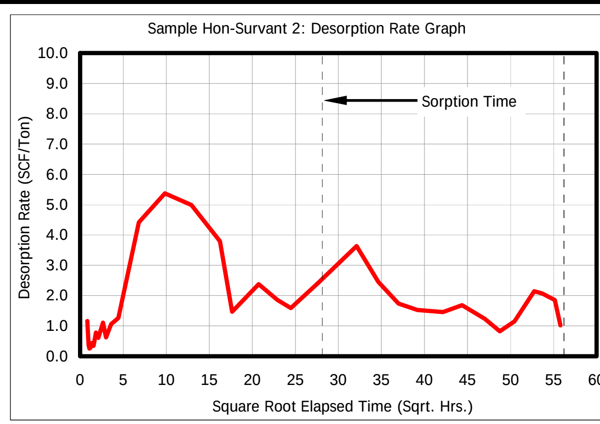
USBM			Smith and Williams	
(%)	(As-Received) (scf/ton)	(DMMF) (scf/ton)	(%)	(As-Received) (scf/ton)
1.3	0.8	1.0	1.5	0.9

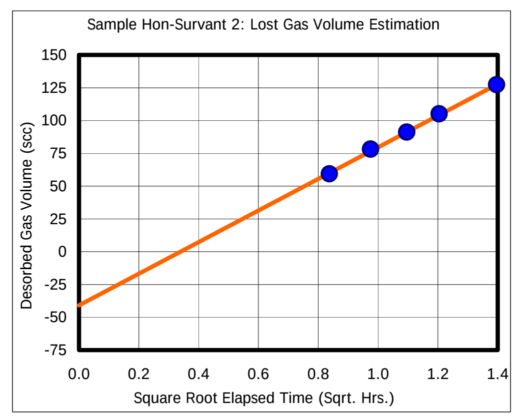
Total Gas Volume

USBM			Smith and Williams		
(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)	(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)
72.6	89.4	92.7	72.7	89.5	92.8

Other Components					Residual Gas Volume		
Sulfur (wt%)	Moisture (wt%)	Ash (wt%)	Moisture Plus Ash (wt%)	Sulfur, Moisture and Ash (wt%)	[As-Received] (scf/ton)	[DAF] (scf/ton)	[DMMF] (scf/ton)
3.91	9.96	8.90	18.86	21.72	12.40	15.28	15.84







Well:	Hon #9
Operator:	Royal Drilling Co
Location:	White County
Field:	0
Formation:	Pennsylvanian, Survant Coal
Comments:	Coal seam is 993 ft deep and 3.7 ft thick

Basic Information

Sample ID	Canister Number	Driller's Depth (feet)	As-Received Sample Weight (g)	DAF Sample Weight (g)	DMMF Sample Weight (g)	Measured Desorption (scm^3)	Sorption Time (hr) for 63.2% of Measured Desorption
Hon-Survant 3	C5	996.4	1717	1431	1396	3240.3	727.4

Sorption Time (hr) for 63.2% of Total Gas
1271.2

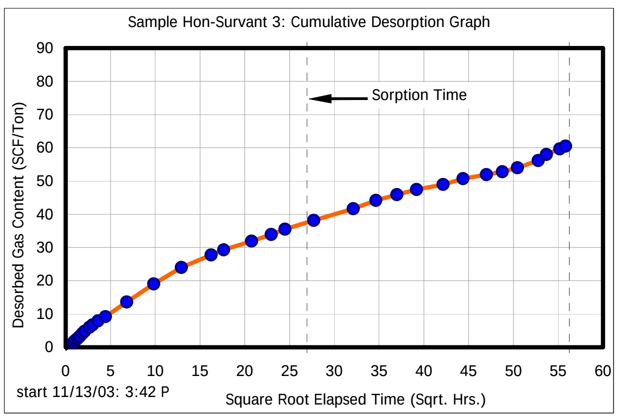
Lost Gas Volume

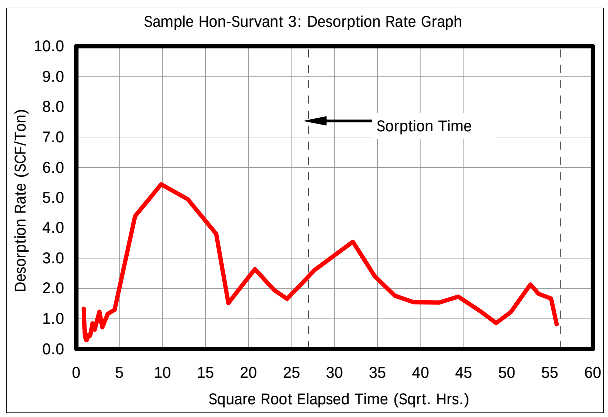
USBM			Smith and Williams	
(%)	(As-Received) (scf/ton)	(DMMF) (scf/ton)	(%)	(As-Received) (scf/ton)
1.4	0.9	1.1	1.7	1.0

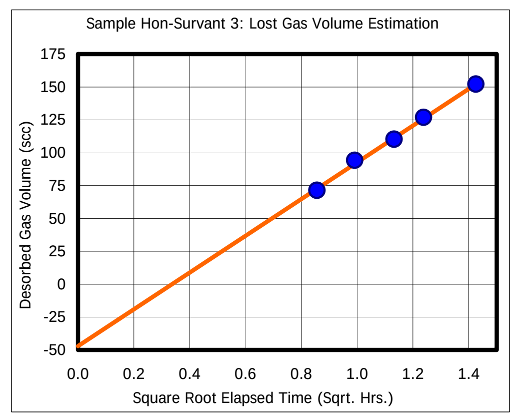
Total Gas Volume

USBM			Smith and Williams		
(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)	(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)
71.0	85.1	87.3	71.1	85.3	87.5

Other Components					Residual Gas Volume		
Sulfur (wt%)	Moisture (wt%)	Ash (wt%)	Moisture Plus Ash (wt%)	Sulfur, Moisture and Ash (wt%)	[As-Received] (scf/ton)	[DAF] (scf/ton)	[DMMF] (scf/ton)
2.48	7.87	8.78	16.65	18.72	9.62	11.54	11.84







Well:	Hon #9
Operator:	Royal Drilling Co
Location:	White County
Field:	0
Formation:	Pennsylvanian, Mecca Quary Shale
Comments:	Shale is 1058 ft deep and 4.3 ft thick

Basic Information

Sample ID	Canister Number	Driller's Depth (feet)	As-Received Sample Weight (g)	DAF Sample Weight (g)	DMMF Sample Weight (g)	Measured Desorption (scm^3)	Sorption Time (hr) for 63.2% of Measured Desorption
n-Mecca Quary Sha	A1	1058	3294	487	195	400.8	620.7

Lost Gas Volume

USBM			Smith and Williams	
(%)	(As-Received) (scf/ton)	(DMMF) (scf/ton)	(%)	(As-Received) (scf/ton)
0.0	0.0	0.0	1.1	0.0

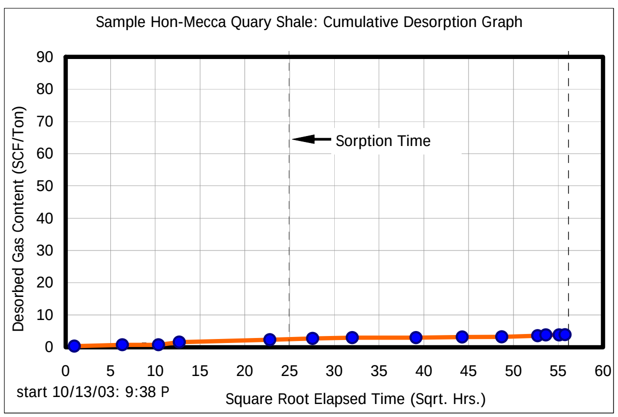
Sorption Time (hr) for 63.2% of Total Gas

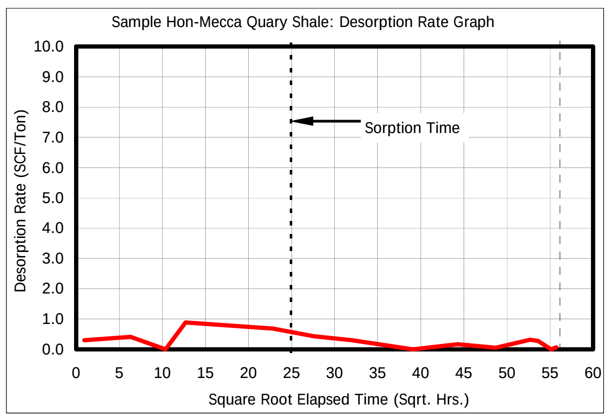
cannot be **determined** or use the max desorption time of 3108 hr

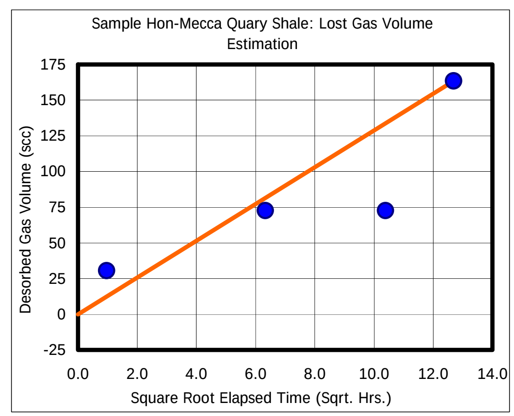
Total Gas Volume

USBM			Smith and Williams		
(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)	(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)
8.6	57.9	145.0	8.6	58.2	145.7

Other Components					Residual Gas Volume		
Sulfur (wt%)	Moisture (wt%)	Ash (wt%)	Moisture Plus Ash (wt%)	Sulfur, Moisture and Ash (wt%)	[As-Received] (scf/ton)	[DAF] (scf/ton)	[DMMF] (scf/ton)
4.67	6.32	78.89	85.21	94.09	4.67	31.58	79.01







Well:	Wasem C-1
Operator:	Howard Energy
Location:	White County
Field:	0
Formation:	Pennsylvanian, Springfield Coal
Comments:	Coal seam is 532 ft deep and 5.1 ft thick

Basic Information

Sample ID	Canister Number	Driller's Depth (feet)	As-Received Sample Weight (g)	DAF Sample Weight (g)	DMMF Sample Weight (g)	Measured Desorption (scm^3)	Sorption Time (hr) for 63.2% of Measured Desorption
Wasem#C1-Springfield 2	D2	533.1	1897	1626	1592	3590.1	350.9

Sorption Time (hr) for 63.2% of Total Gas
682

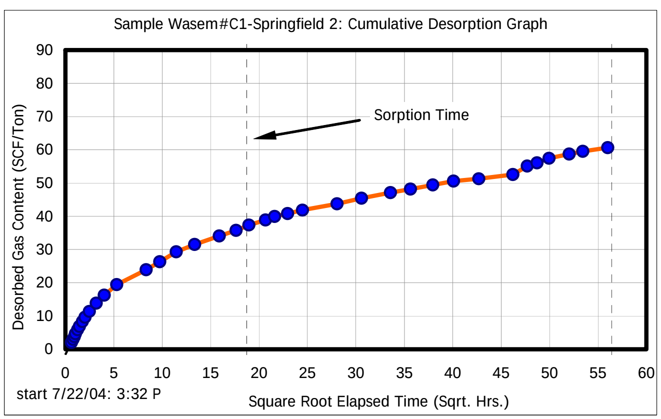
Lost Gas Volume

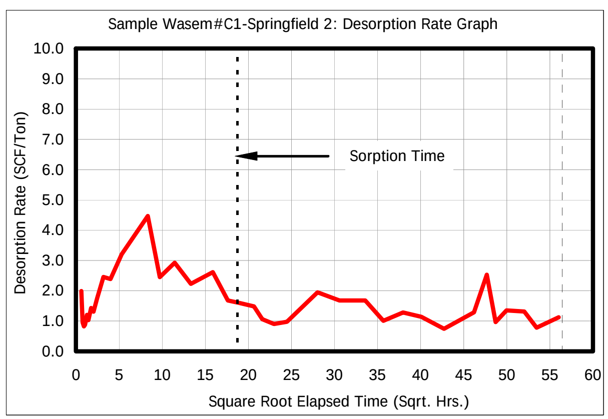
USBM			Smith and Williams	
(%)	(As-Received) (scf/ton)	(DMMF) (scf/ton)	(%)	(As-Received) (scf/ton)
2.7	1.7	2.0	2.5	1.5

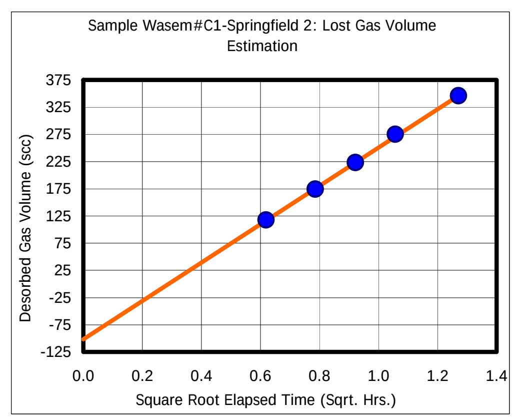
Total Gas Volume

USBM			Smith and Williams		
(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)	(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)
67.5	78.7	80.4	67.3	78.5	80.2

Other Components					Residual Gas Volume		
Sulfur (wt%)	Moisture (wt%)	Ash (wt%)	Moisture Plus Ash (wt%)	Sulfur, Moisture and Ash (wt%)	[As-Received] (scf/ton)	[DAF] (scf/ton)	[DMMF] (scf/ton)
2.23	7.27	6.98	14.25	16.03	5.12	5.97	6.10







Well:	Wasem C-1
Operator:	Howard Energy
Location:	White County
Field:	0
Formation:	Pennsylvanian, Springfield Coal
Comments:	Coal seam is 532 ft deep and 5.1 ft thick

Basic Information

Sample ID	Canister Number	Driller's Depth (feet)	As-Received Sample Weight (g)	DAF Sample Weight (g)	DMMF Sample Weight (g)	Measured Desorption (scm^3)	Sorption Time (hr) for 63.2% of Measured Desorption
Wasem#C1-Springfield 3	D3	535	1831	1511	1453	3364.8	566.8

Sorption Time (hr) for 63.2% of Total Gas
988

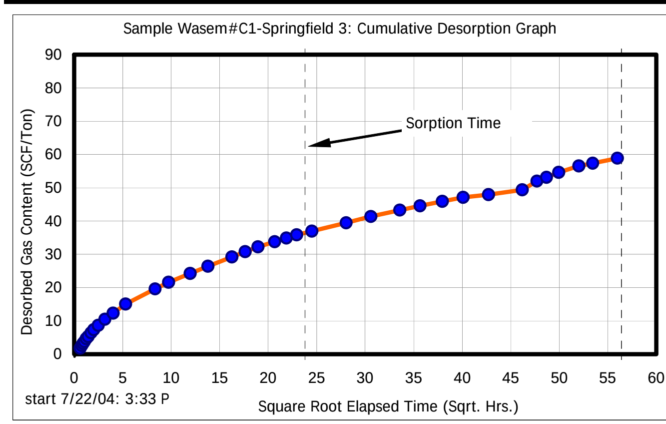
Lost Gas Volume

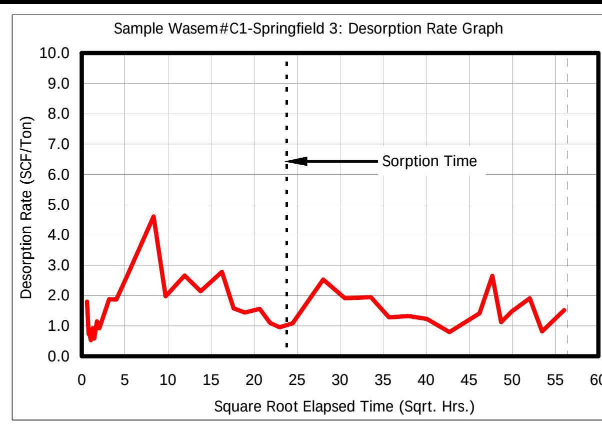
USBM			Smith and Williams	
(%)	(As-Received) (scf/ton)	(DMMF) (scf/ton)	(%)	(As-Received) (scf/ton)
1.8	1.1	1.3	2.0	1.2

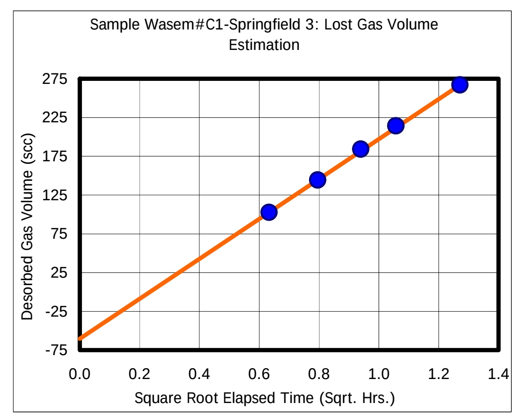
Total Gas Volume

USBM			Smith and Williams		
(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)	(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)
66.3	80.3	83.5	66.4	80.5	83.7

Other Components					Residual Gas Volume		
Sulfur (wt%)	Moisture (wt%)	Ash (wt%)	Moisture Plus Ash (wt%)	Sulfur, Moisture and Ash (wt%)	[As-Received] (scf/ton)	[DAF] (scf/ton)	[DMMF] (scf/ton)
4.13	6.66	10.83	17.49	20.63	6.34	7.68	7.99







Well:	Wasem C-1
Operator:	Howard Energy
Location:	White County
Field:	0
Formation:	Pennsylvanian, Excello Shale
Comments:	Shale is 601 ft deep and 2.3 ft thick

Basic Information

Sample ID	Canister Number	Driller's Depth (feet)	As-Received Sample Weight (g)	DAF Sample Weight (g)	DMMF Sample Weight (g)	Measured Desorption (scm^3)	Sorption Time (hr) for 63.2% of Measured Desorption
Wasem#C1 - Excello Shale	F12	601	2558	727	553	2114.8	471.1

Sorption Time (hr) for 63.2% of Total Gas
616

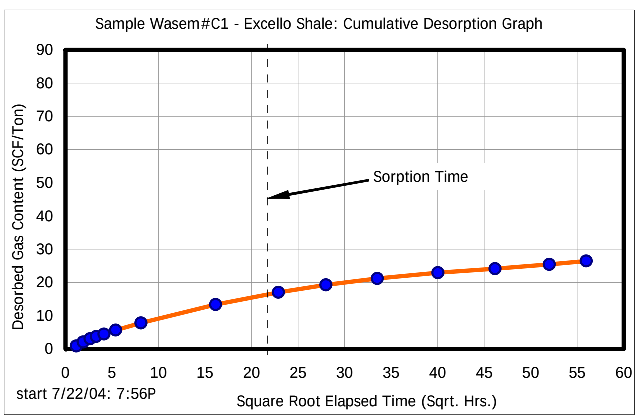
Lost Gas Volume

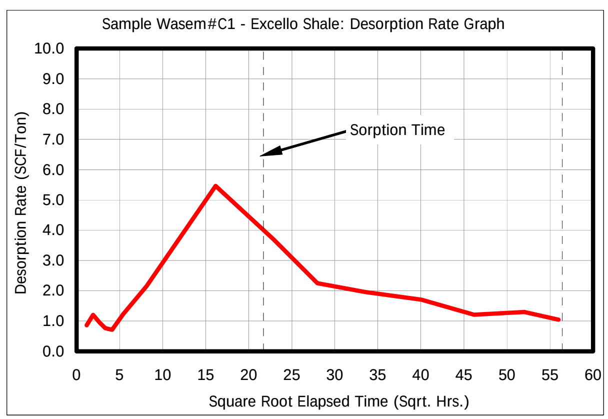
USBM			Smith and Williams	
(%)	(As-Received) (scf/ton)	(DMMF) (scf/ton)	(%)	(As-Received) (scf/ton)
2.3	0.6	2.9	2.8	0.8

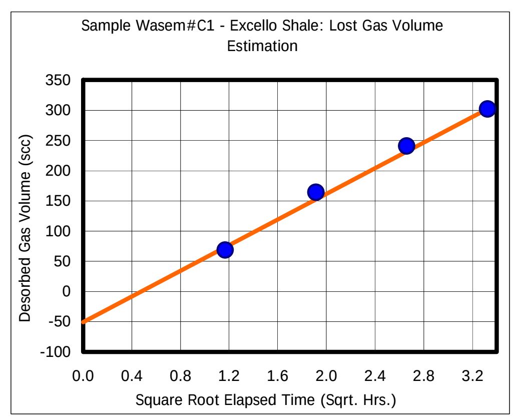
Total Gas Volume

USBM			Smith and Williams		
(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)	(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)
28.2	99.1	130.3	28.3	99.6	130.9

Other Components					Residual Gas Volume		
Sulfur (wt%)	Moisture (wt%)	Ash (wt%)	Moisture Plus Ash (wt%)	Sulfur, Moisture and Ash (wt%)	[As-Received] (scf/ton)	[DAF] (scf/ton)	[DMMF] (scf/ton)
2.64	4.61	66.97	71.58	78.39	1.05	3.69	4.86







Well:	Wasem C-1
Operator:	Howard Energy
Location:	White County
Field:	0
Formation:	Pennsylvanian, Houchin Creek Coal
Comments:	Coal seam is 602 ft deep and 2.9 ft thick

Basic Information

Sample ID	Canister Number	Driller's Depth (feet)	As-Received Sample Weight (g)	DAF Sample Weight (g)	DMMF Sample Weight (g)	Measured Desorption (scm^3)	Sorption Time (hr) for 63.2% of Measured Desorption
Wasem#C1-Houchin Creek	D4	603.6	1598	1364	1333	2477.0	796.5

Sorption Time (hr) for 63.2% of Total Gas
2274

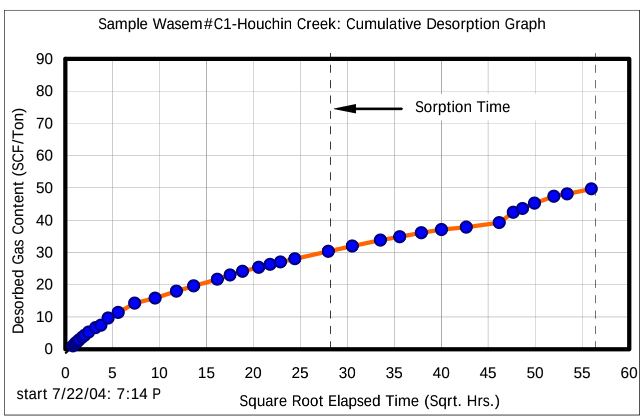
Lost Gas Volume

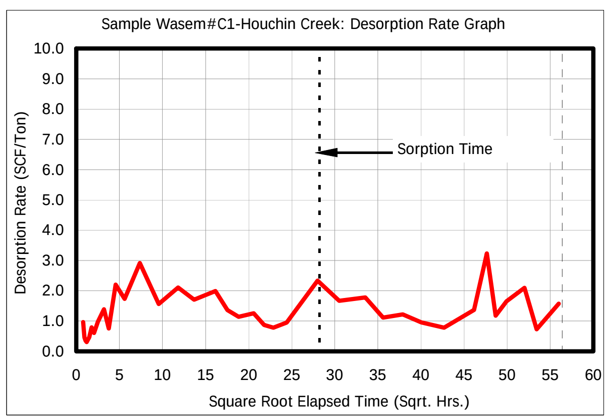
USBM			Smith and Williams	
(%)	(As-Received) (scf/ton)	(DMMF) (scf/ton)	(%)	(As-Received) (scf/ton)
2.6	1.3	1.6	2.1	1.1

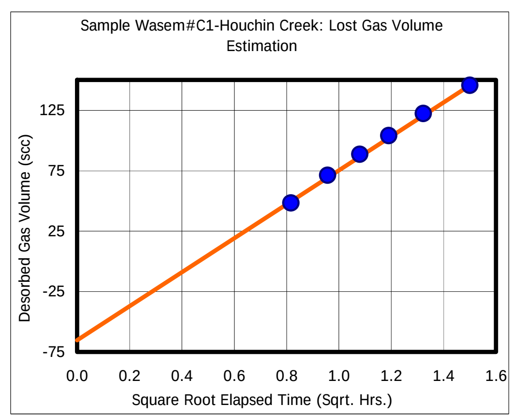
Total Gas Volume

USBM			Smith and Williams		
(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)	(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)
67.2	78.7	80.5	66.9	78.4	80.2

Other Components					Residual Gas Volume		
Sulfur (wt%)	Moisture (wt%)	Ash (wt%)	Moisture Plus Ash (wt%)	Sulfur, Moisture and Ash (wt%)	[As-Received] (scf/ton)	[DAF] (scf/ton)	[DMMF] (scf/ton)
2.56	7.73	6.88	14.61	16.57	16.18	18.95	19.39







Well:	Wasem C-1
Operator:	Howard Energy
Location:	White County
Field:	0
Formation:	Pennsylvanian, Survant Coal
Comments:	Coal seam is 647 ft deep and 1.7 ft thick

Basic Information

Sample ID	Canister Number	Driller's Depth (feet)	As-Received Sample Weight (g)	DAF Sample Weight (g)	DMMF Sample Weight (g)	Measured Desorption (scm^3)	Sorption Time (hr) for 63.2% of Measured Desorption
Wasem#C1-Survant	D5	644	1761	1449	1381	3496.7	440.6

Sorption Time (hr) for 63.2% of Total Gas
1031

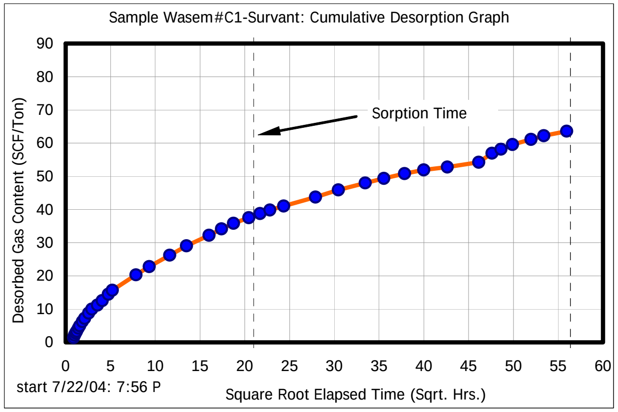
Lost Gas Volume

USBM			Smith and Williams	
(%)	(As-Received) (scf/ton)	(DMMF) (scf/ton)	(%)	(As-Received) (scf/ton)
4.8	3.2	4.1	2.2	1.5

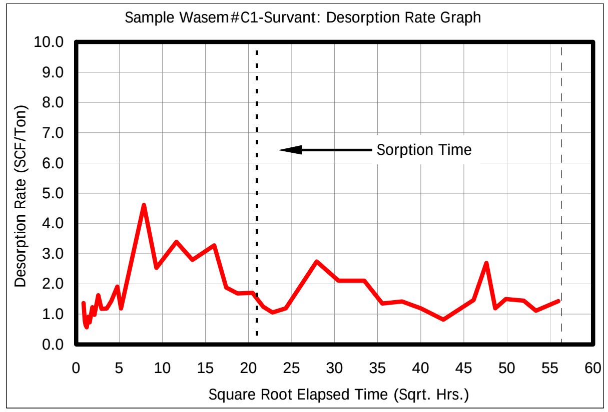
Total Gas Volume

USBM			Smith and Williams		
(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)	(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)
74.4	90.4	94.9	72.6	88.3	92.6

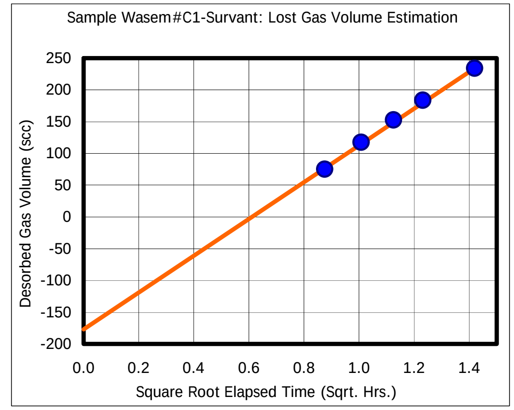
Other Components					Residual Gas Volume		
Sulfur (wt%)	Moisture (wt%)	Ash (wt%)	Moisture Plus Ash (wt%)	Sulfur, Moisture and Ash (wt%)	[As-Received] (scf/ton)	[DAF] (scf/ton)	[DMMF] (scf/ton)
5.47	6.83	10.87	17.70	21.58	7.55	9.17	9.63



Sample Wasem#C1-Survant: Cumulative Desorption Graph



Sample Wasem#C1-Survant: Desorption Rate Graph



Sample Wasem#C1-Survant: Lost Gas Volume Estimation

Well:	Wasem C-1
Operator:	Howard Energy
Location:	White County
Field:	0
Formation:	Pennsylvanian, Mecca Quary Shale
Comments:	Shale is 695 ft deep and 2.9 ft thick

Basic Information

Sample ID	Canister Number	Driller's Depth (feet)	As-Received Sample Weight (g)	DAF Sample Weight (g)	DMMF Sample Weight (g)	Measured Desorption (scm^3)	Sorption Time (hr) for 63.2% of Measured Desorption	Sorption Time (hr) for 63.2% of Total Gas
Wasem#C1 - MeccaQuary Shale	F13	696.5	2920	588	358	1079.7	823.0	1003

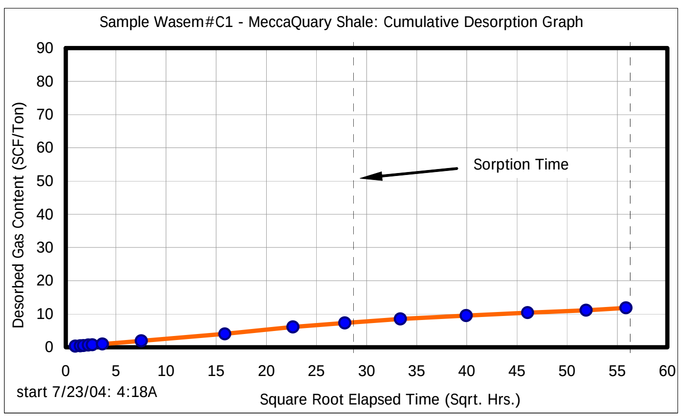
Lost Gas Volume

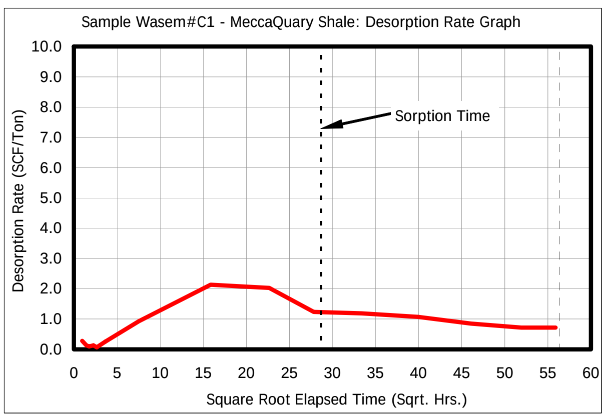
USBM			Smith and Williams	
(%)	(As-Received) (scf/ton)	(DMMF) (scf/ton)	(%)	(As-Received) (scf/ton)
0.0	0.0	0.0	0.8	0.1

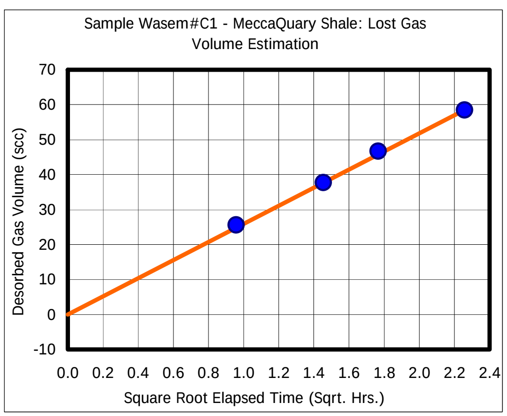
Total Gas Volume

USBM			Smith and Williams		
(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)	(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)
12.8	63.5	104.2	12.9	64.0	105.0

Other Components					Residual Gas Volume		
Sulfur (wt%)	Moisture (wt%)	Ash (wt%)	Moisture Plus Ash (wt%)	Sulfur, Moisture and Ash (wt%)	[As-Received] (scf/ton)	[DAF] (scf/ton)	[DMMF] (scf/ton)
3.25	3.80	76.05	79.85	87.72	0.95	4.71	7.74







Well:	Wasem C-1
Operator:	Howard Energy
Location:	White County
Field:	0
Formation:	Pennsylvanian, Davis Coal
Comments:	Coal seam is 807 ft deep and 6 ft thick(thicness excludes the parting between 808.6 and 815.9 ft)

Basic Information

Sample ID	Canister Number	Driller's Depth (feet)	As-Received Sample Weight (g)	DAF Sample Weight (g)	DMMF Sample Weight (g)	Measured Desorption (scm^3)	Sorption Time (hr) for 63.2% of Measured Desorption
Wasem#C1-Davis 1	E1	808	1844	1516	1434	2676.2	714.9

Sorption Time (hr) for 63.2% of Total Gas
1970

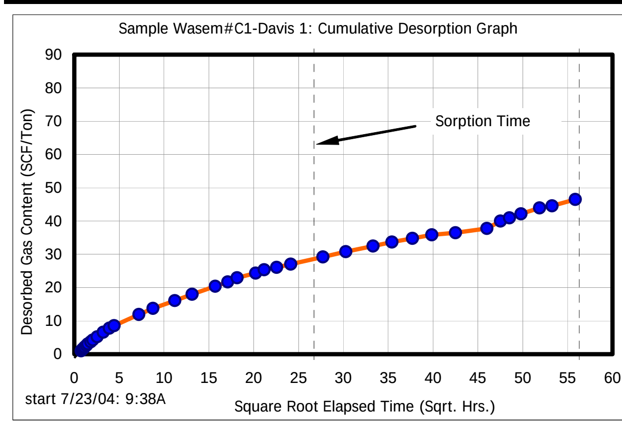
Lost Gas Volume

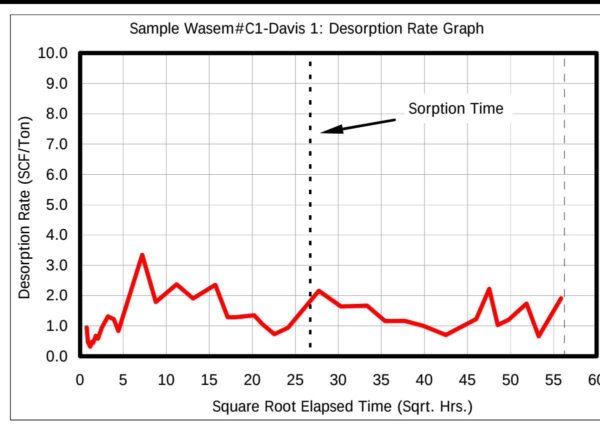
USBM			Smith and Williams	
(%)	(As-Received) (scf/ton)	(DMMF) (scf/ton)	(%)	(As-Received) (scf/ton)
2.5	1.2	1.5	1.7	0.8

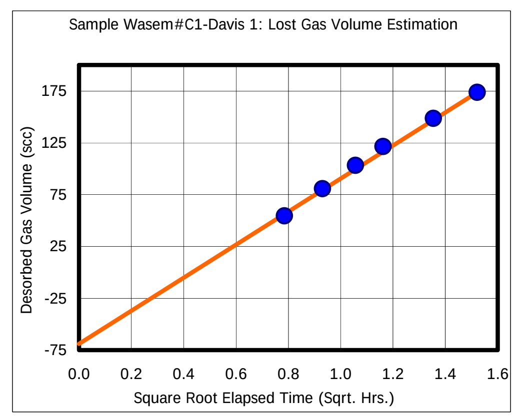
Total Gas Volume

USBM			Smith and Williams		
(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)	(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)
58.8	71.5	75.5	58.4	71.0	75.0

Other Components					Residual Gas Volume		
Sulfur (wt%)	Moisture (wt%)	Ash (wt%)	Moisture Plus Ash (wt%)	Sulfur, Moisture and Ash (wt%)	[As-Received] (scf/ton)	[DAF] (scf/ton)	[DMMF] (scf/ton)
6.33	6.32	11.47	17.79	22.19	11.06	13.45	14.21







Well:	Wasem C-1
Operator:	Howard Energy
Location:	White County
Field:	0
Formation:	Pennsylvanian, Davis Coal
Comments:	Coal seam is 807 ft deep and 6 ft thick(thicness excludes the parting between 808.6 and 815.9 ft)

Basic Information

Sample ID	Canister Number	Driller's Depth (feet)	As-Received Sample Weight (g)	DAF Sample Weight (g)	DMMF Sample Weight (g)	Measured Desorption (scm^3)	Sorption Time (hr) for 63.2% of Measured Desorption
Wasem#C1-Davis 2	E2	816.8	1777	1548	1514	3421.6	561.4

Sorption Time (hr) for 63.2% of Total Gas
1168

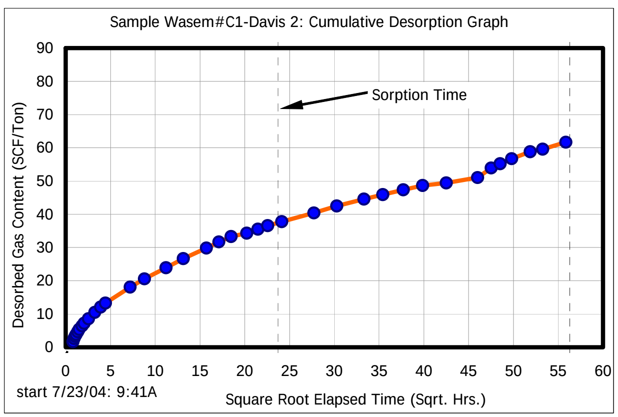
Lost Gas Volume

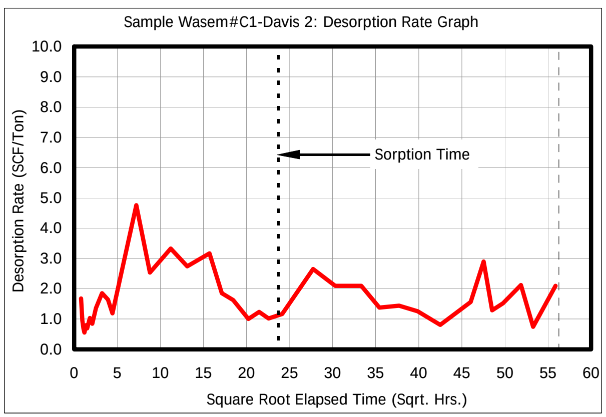
USBM			Smith and Williams	
(%)	(As-Received) (scf/ton)	(DMMF) (scf/ton)	(%)	(As-Received) (scf/ton)
3.7	2.3	2.7	2.2	1.4

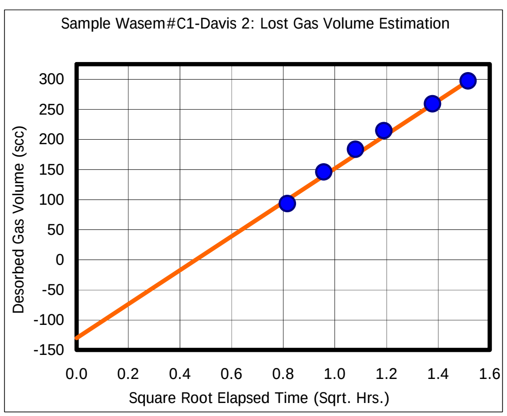
Total Gas Volume

USBM			Smith and Williams		
(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)	(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)
71.4	81.9	83.7	70.4	80.8	82.6

Other Components					Residual Gas Volume		
Sulfur (wt%)	Moisture (wt%)	Ash (wt%)	Moisture Plus Ash (wt%)	Sulfur, Moisture and Ash (wt%)	[As-Received] (scf/ton)	[DAF] (scf/ton)	[DMMF] (scf/ton)
2.58	6.68	6.19	12.87	14.78	7.34	8.42	8.61







Well:	Wasem C-1
Operator:	Howard Energy
Location:	White County
Field:	0
Formation:	Pennsylvanian, Davis Coal
Comments:	Coal seam is 807 ft deep and 6 ft thick(thicness excludes the parting between 808.6 and 815.9 ft)

Basic Information

Sample ID	Canister Number	Driller's Depth (feet)	As-Received Sample Weight (g)	DAF Sample Weight (g)	DMMF Sample Weight (g)	Measured Desorption (scm^3)	Sorption Time (hr) for 63.2% of Measured Desorption
Wasem#C1-Davis 3	E3	818.3	1702	1444	1414	3136.8	618.6

Sorption Time (hr) for 63.2% of Total Gas
1189

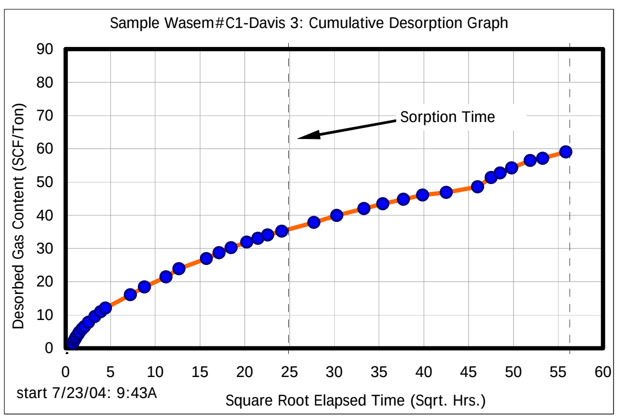
Lost Gas Volume

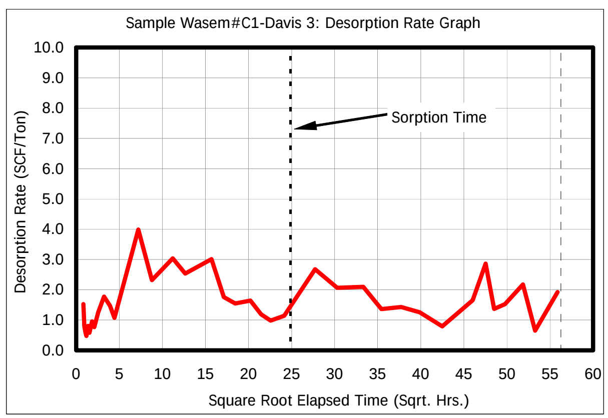
USBM			Smith and Williams	
(%)	(As-Received) (scf/ton)	(DMMF) (scf/ton)	(%)	(As-Received) (scf/ton)
3.8	2.3	2.8	2.1	1.3

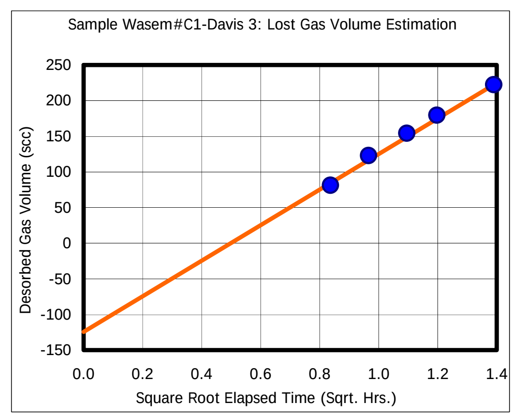
Total Gas Volume

USBM			Smith and Williams		
(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)	(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)
67.7	79.8	81.5	66.6	78.5	80.2

Other Components					Residual Gas Volume		
Sulfur (wt%)	Moisture (wt%)	Ash (wt%)	Moisture Plus Ash (wt%)	Sulfur, Moisture and Ash (wt%)	[As-Received] (scf/ton)	[DAF] (scf/ton)	[DMMF] (scf/ton)
1.96	6.44	8.73	15.17	16.95	6.32	7.45	7.61







Well:	Wasem C-1
Operator:	Howard Energy
Location:	White County
Field:	0
Formation:	Pennsylvanian, Mt Rorah Coal
Comments:	Coal seam is 887 ft deep and 2.5 ft thick

Basic Information

Sample ID	Canister Number	Driller's Depth (feet)	As-Received Sample Weight (g)	DAF Sample Weight (g)	DMMF Sample Weight (g)	Measured Desorption (scm^3)	Sorption Time (hr) for 63.2% of Measured Desorption
Wasem#C1-Mt Rorah 1	E4	887.3	1943	1537	1458	1451.2	1050.6

Sorption Time (hr) for 63.2% of Total Gas
2261

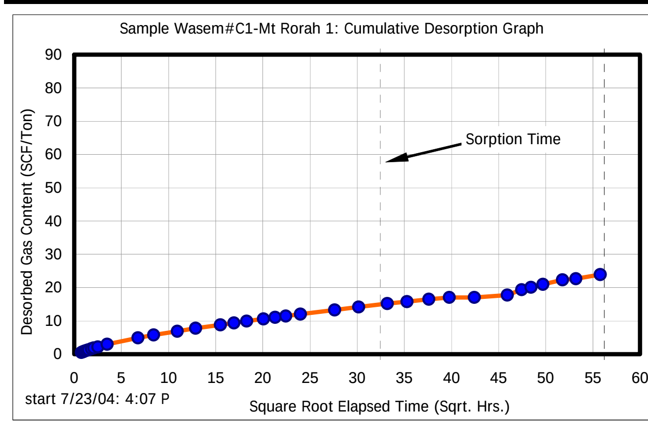
Lost Gas Volume

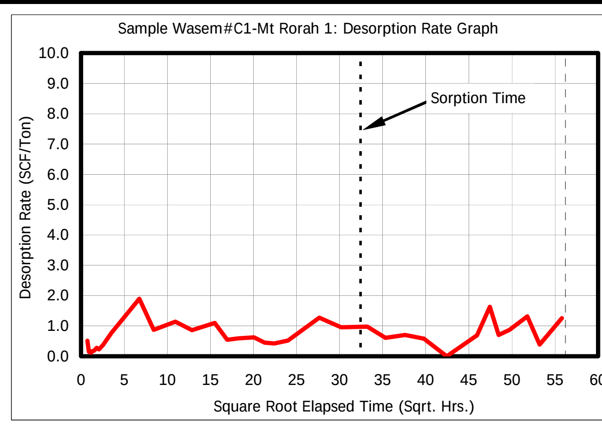
USBM			Smith and Williams	
(%)	(As-Received) (scf/ton)	(DMMF) (scf/ton)	(%)	(As-Received) (scf/ton)
1.1	0.3	0.3	0.9	0.2

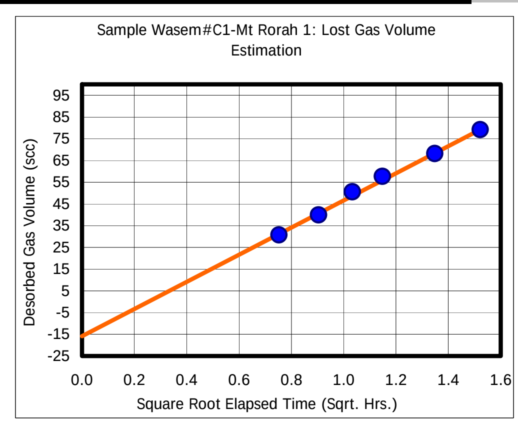
Total Gas Volume

USBM			Smith and Williams		
(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)	(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)
30.8	38.9	41.0	30.8	38.9	41.0

Other Components					Residual Gas Volume		
Sulfur (wt%)	Moisture (wt%)	Ash (wt%)	Moisture Plus Ash (wt%)	Sulfur, Moisture and Ash (wt%)	[As-Received] (scf/ton)	[DAF] (scf/ton)	[DMMF] (scf/ton)
5.32	6.66	14.23	20.89	24.95	6.61	8.36	8.81







Well:	Wasem C-1
Operator:	Howard Energy
Location:	White County
Field:	0
Formation:	Pennsylvanian, Mt Rorah Coal
Comments:	Coal seam is 887 ft deep and 2.5 ft thick

Basic Information

Sample ID	Canister Number	Driller's Depth (feet)	As-Received Sample Weight (g)	DAF Sample Weight (g)	DMMF Sample Weight (g)	Measured Desorption (scm^3)	Sorption Time (hr) for 63.2% of Measured Desorption
Wasem#C1-Mt Rorah 2	E5	899.2	2090	1680	1574	1617.2	894.2

Sorption Time (hr) for 63.2% of Total Gas
2136

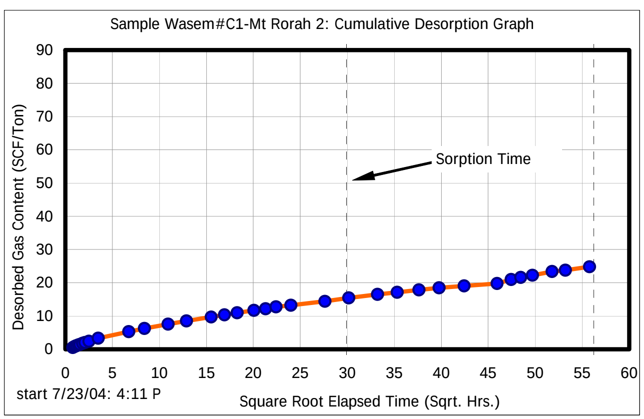
Lost Gas Volume

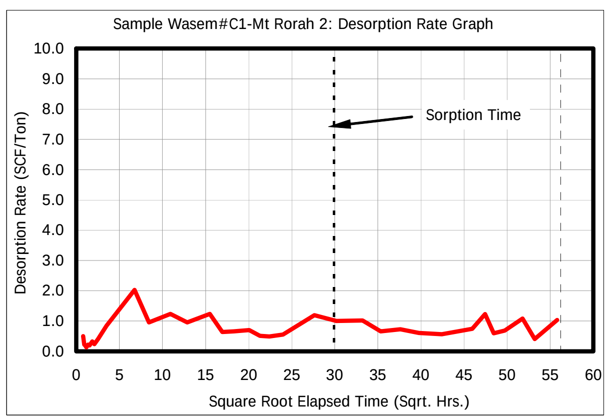
USBM			Smith and Williams	
(%)	(As-Received) (scf/ton)	(DMMF) (scf/ton)	(%)	(As-Received) (scf/ton)
1.9	0.5	0.6	1.3	0.3

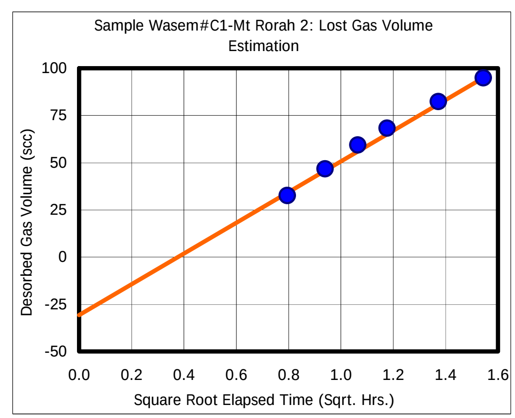
Total Gas Volume

USBM			Smith and Williams		
(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)	(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)
31.6	39.2	41.9	31.4	39.1	41.7

Other Components					Residual Gas Volume		
Sulfur (wt%)	Moisture (wt%)	Ash (wt%)	Moisture Plus Ash (wt%)	Sulfur, Moisture and Ash (wt%)	[As-Received] (scf/ton)	[DAF] (scf/ton)	[DMMF] (scf/ton)
7.29	6.28	13.32	19.60	24.68	6.29	7.82	8.35







Well:	Ameren #1-24
Operator:	Peabody Natural Gas LLC
Location:	Jasper County/IL; NWc NW NW NW, Sec24-6N-8E
Field:	Newton Power Plant
Formation:	Pennsylvanian, Danville Coal
Comments:	Coal seam is 1188 ft deep and 3.2 ft thick

Basic Information

Sample ID	Canister Number	Driller's Depth (feet)	As-Received Sample Weight (g)	DAF Sample Weight (g)	DMMF Sample Weight (g)	Measured Desorption (scm^3)	Sorption Time (hr) for 63.2% of Measured Desorption
Ameren#1-24 Danville 1	F1	1188	1771	1392	1339	3228.0	769.2

Sorption Time (hr) for 63.2% of Total Gas
1867

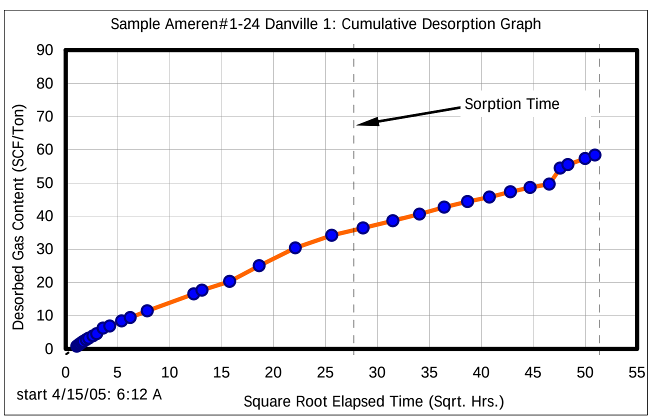
Lost Gas Volume

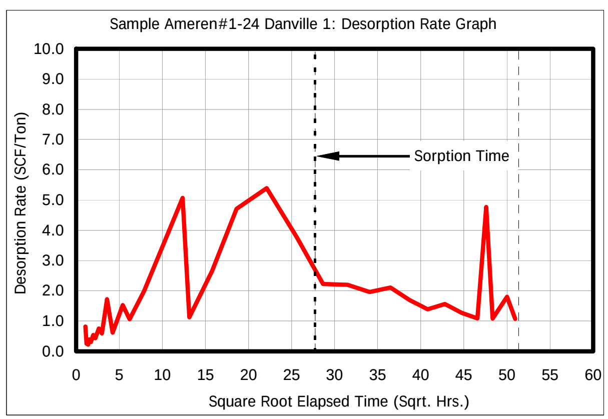
USBM			Smith and Williams	
(%)	(As-Received) (scf/ton)	(DMMF) (scf/ton)	(%)	(As-Received) (scf/ton)
2.9	1.7	2.3	1.4	0.8

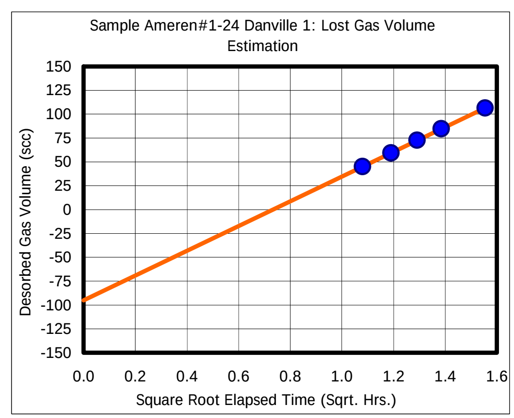
Total Gas Volume

USBM			Smith and Williams		
(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)	(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)
75.3	95.8	99.6	74.4	94.6	98.4

Other Components					Residual Gas Volume		
Sulfur (wt%)	Moisture (wt%)	Ash (wt%)	Moisture Plus Ash (wt%)	Sulfur, Moisture and Ash (wt%)	[As-Received] (scf/ton)	[DAF] (scf/ton)	[DMMF] (scf/ton)
3.49	7.69	13.69	21.38	24.39	15.20	19.33	20.10







Well:	Ameren #1-24
Operator:	Peabody Natural Gas LLC
Location:	Jasper County/IL; NWc NW NW NW, Sec24-6N-8E
Field:	Newton Power Plant
Formation:	Pennsylvanian, Danville Coal
Comments:	Coal seam is 1188 ft deep and 3.2 ft thick

Basic Information

Sample ID	Canister Number	Driller's Depth (feet)	As-Received Sample Weight (g)	DAF Sample Weight (g)	DMMF Sample Weight (g)	Measured Desorption (scm^3)	Sorption Time (hr) for 63.2% of Measured Desorption
Ameren#1-24 Danville 2	F2	1188	1815	1422	1371	3377.0	800.6

Sorption Time (hr) for 63.2% of Total Gas
2189

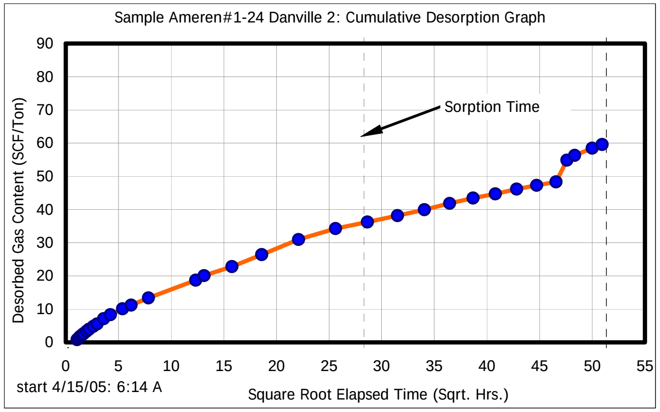
Lost Gas Volume

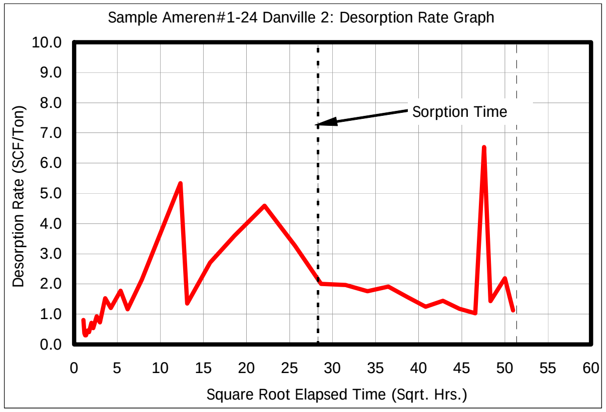
USBM			Smith and Williams	
(%)	(As-Received) (scf/ton)	(DMMF) (scf/ton)	(%)	(As-Received) (scf/ton)
4.0	2.5	3.3	1.9	1.1

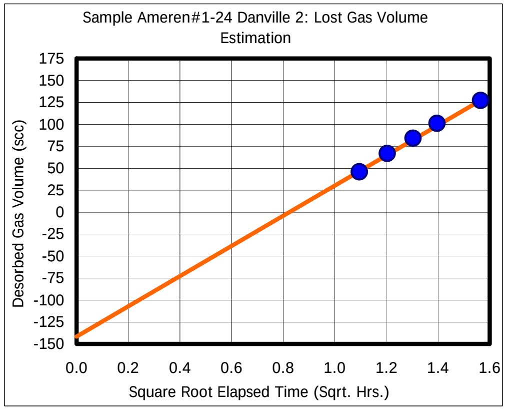
Total Gas Volume

USBM			Smith and Williams		
(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)	(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)
78.7	100.4	104.2	77.3	98.7	102.4

Other Components					Residual Gas Volume		
Sulfur (wt%)	Moisture (wt%)	Ash (wt%)	Moisture Plus Ash (wt%)	Sulfur, Moisture and Ash (wt%)	[As-Received] (scf/ton)	[DAF] (scf/ton)	[DMMF] (scf/ton)
3.19	8.06	13.58	21.64	24.48	16.60	21.18	21.98







Well:	Ameren #1-24
Operator:	Peabody Natural Gas LLC
Location:	Jasper County/IL; NWc NW NW NW, Sec24-6N-8E
Field:	Newton Power Plant
Formation:	Pennsylvanian, Jamestown Coal
Comments:	Coal seam is 1215 ft deep and 2.9 ft thick

Basic Information

Sample ID	Canister Number	Driller's Depth (feet)	As-Received Sample Weight (g)	DAF Sample Weight (g)	DMMF Sample Weight (g)	Measured Desorption (scm^3)	Sorption Time (hr) for 63.2% of Measured Desorption
Ameren#1-24 Jamestown 1	F3	1215.7	2069	1548	1467	4466.5	545.8

Sorption Time (hr) for 63.2% of Total Gas
1450

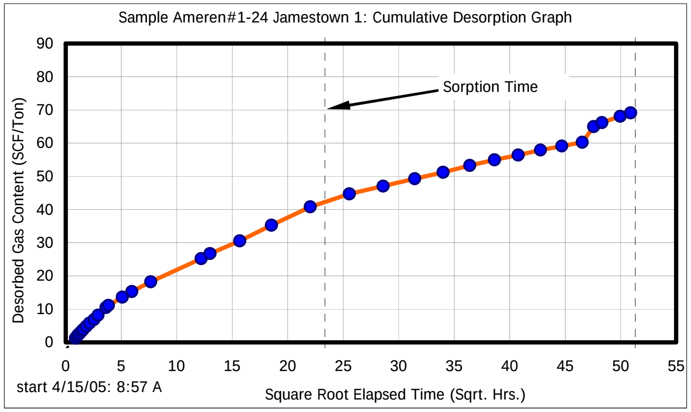
Lost Gas Volume

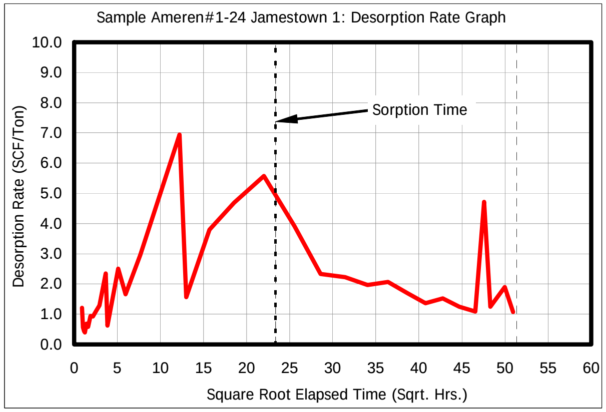
USBM			Smith and Williams	
(%)	(As-Received) (scf/ton)	(DMMF) (scf/ton)	(%)	(As-Received) (scf/ton)
3.0	2.1	3.0	1.9	1.4

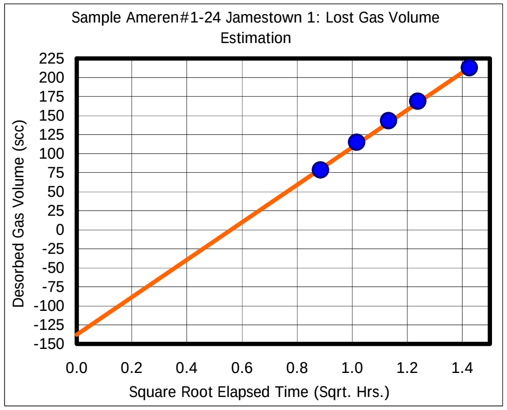
Total Gas Volume

USBM			Smith and Williams		
(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)	(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)
86.3	115.3	121.7	85.5	114.3	120.6

Other Components					Residual Gas Volume		
Sulfur (wt%)	Moisture (wt%)	Ash (wt%)	Moisture Plus Ash (wt%)	Sulfur, Moisture and Ash (wt%)	[As-Received] (scf/ton)	[DAF] (scf/ton)	[DMMF] (scf/ton)
4.45	6.69	18.48	25.17	29.10	15.00	20.05	21.16







Well:	Ameren #1-24
Operator:	Peabody Natural Gas LLC
Location:	Jasper County/IL; NWc NW NW NW, Sec24-6N-8E
Field:	Newton Power Plant
Formation:	Pennsylvanian, Jamestown Coal
Comments:	Coal seam is 1215 ft deep and 2.9 ft thick

Basic Information

Sample ID	Canister Number	Driller's Depth (feet)	As-Received Sample Weight (g)	DAF Sample Weight (g)	DMMF Sample Weight (g)	Measured Desorption (scm^3)	Sorption Time (hr) for 63.2% of Measured Desorption
Ameren#1-24 Jamestown 2	F4	1216.8	2171	1400	1301	4559.9	407.1

Lost Gas Volume

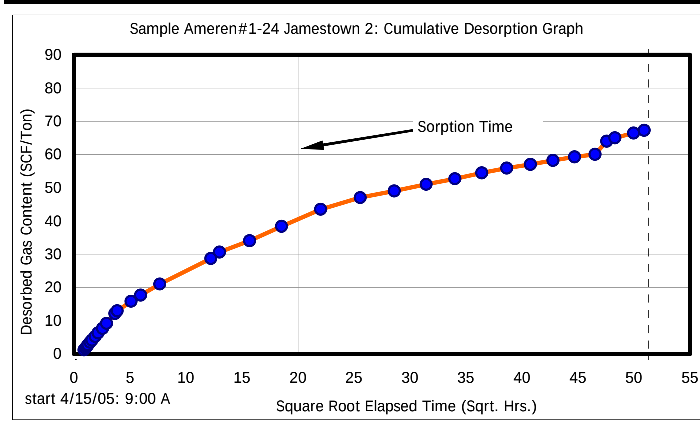
USBM			Smith and Williams	
(%)	(As-Received) (scf/ton)	(DMMF) (scf/ton)	(%)	(As-Received) (scf/ton)
3.9	2.7	4.5	2.3	1.6

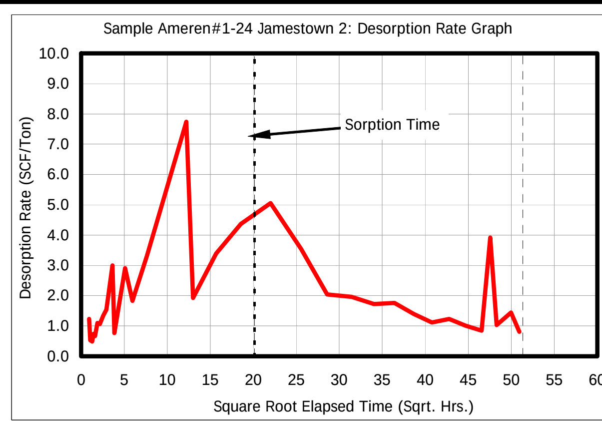
Sorption Time (hr) for 63.2% of Total Gas
917

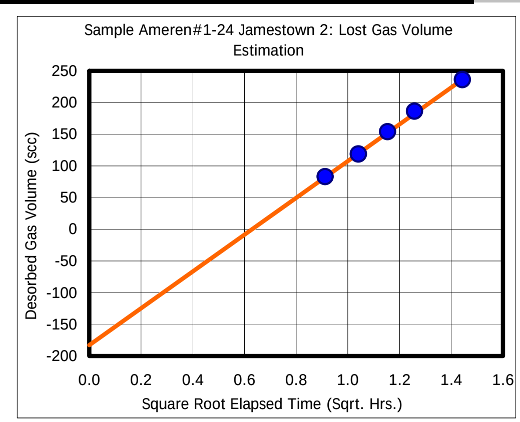
Total Gas Volume

USBM			Smith and Williams		
(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)	(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)
79.4	123.1	132.5	78.3	121.4	130.7

Other Components					Residual Gas Volume		
Sulfur (wt%)	Moisture (wt%)	Ash (wt%)	Moisture Plus Ash (wt%)	Sulfur, Moisture and Ash (wt%)	[As-Received] (scf/ton)	[DAF] (scf/ton)	[DMMF] (scf/ton)
4.02	6.07	29.46	35.53	40.10	9.40	14.58	15.69







Well:	Ameren #1-24
Operator:	Peabody Natural Gas LLC
Location:	Jasper County/IL; NWc NW NW NW, Sec24-6N-8E
Field:	Newton Power Plant
Formation:	Pennsylvanian, Anna Shale
Comments:	Shale is 1225 ft deep

Basic Information

Sample ID	Canister Number	Driller's Depth (feet)	As-Received Sample Weight (g)	DAF Sample Weight (g)	DMMF Sample Weight (g)	Measured Desorption (scm^3)	Sorption Time (hr) for 63.2% of Measured Desorption
Ameren#1-24 Anna Shale	E3	1225.9	3152	590	356	1086.1	638.9

Sorption Time (hr) for 63.2% of Total Gas
2034

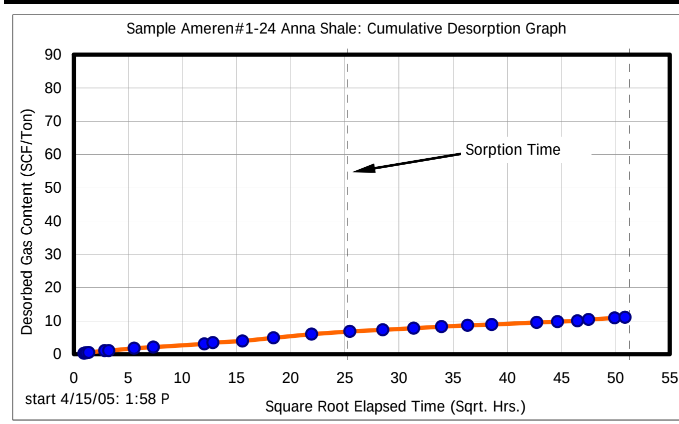
Lost Gas Volume

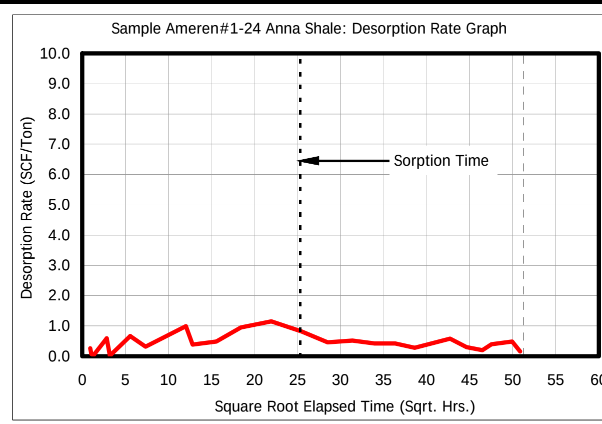
USBM			Smith and Williams	
(%)	(As-Received) (scf/ton)	(DMMF) (scf/ton)	(%)	(As-Received) (scf/ton)
2.6	0.3	2.6	1.0	0.1

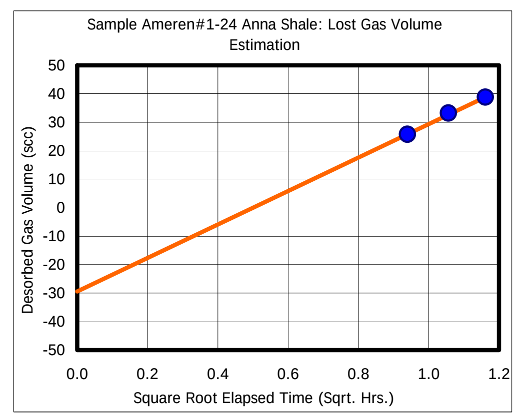
Total Gas Volume

USBM			Smith and Williams		
(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)	(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)
15.6	83.6	138.4	15.5	82.6	136.8

Other Components					Residual Gas Volume		
Sulfur (wt%)	Moisture (wt%)	Ash (wt%)	Moisture Plus Ash (wt%)	Sulfur, Moisture and Ash (wt%)	[As-Received] (scf/ton)	[DAF] (scf/ton)	[DMMF] (scf/ton)
2.35	4.78	76.51	81.29	88.70	4.30	22.98	38.06







Well:	Ameren #1-24
Operator:	Peabody Natural Gas LLC
Location:	Jasper County/IL; NWc NW NW NW, Sec24-6N-8E
Field:	Newton Power Plant
Formation:	Pennsylvanian, Herrin Coal
Comments:	Coal seam is 1226 ft deep and 6.1 ft thick

Basic Information

Sample ID	Canister Number	Driller's Depth (feet)	As-Received Sample Weight (g)	DAF Sample Weight (g)	DMMF Sample Weight (g)	Measured Desorption (scm^3)	Sorption Time (hr) for 63.2% of Measured Desorption
Ameren#1-24 Herrin 1	F5	1229.7	1970	1425	1371	4382.5	470.6

Sorption Time (hr) for 63.2% of Total Gas
1074

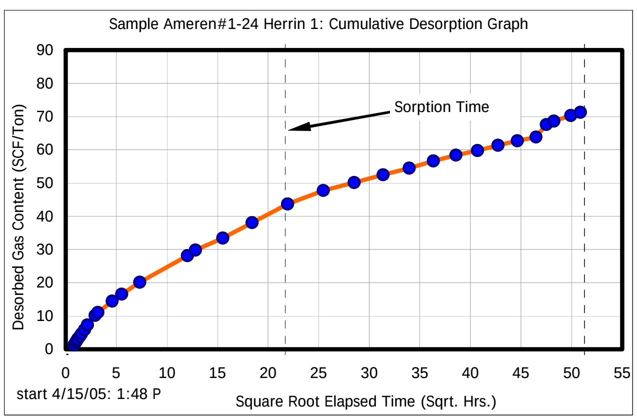
Lost Gas Volume

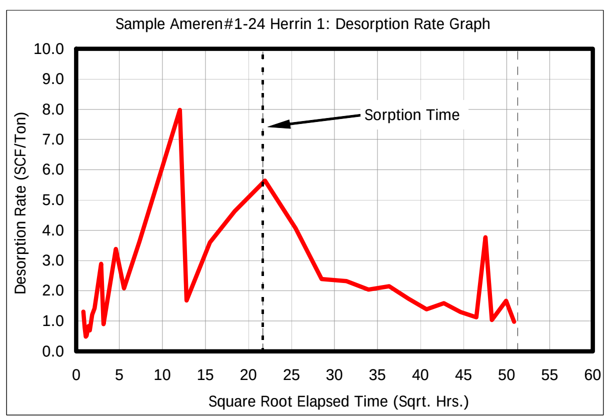
USBM			Smith and Williams	
(%)	(As-Received) (scf/ton)	(DMMF) (scf/ton)	(%)	(As-Received) (scf/ton)
3.5	2.6	3.7	2.0	1.5

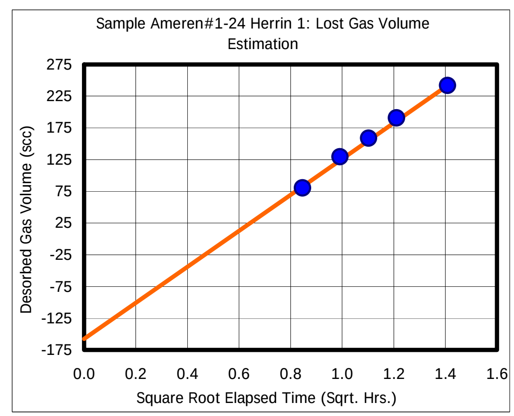
Total Gas Volume

USBM			Smith and Williams		
(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)	(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)
84.7	117.1	121.7	83.6	115.6	120.2

Other Components					Residual Gas Volume		
Sulfur (wt%)	Moisture (wt%)	Ash (wt%)	Moisture Plus Ash (wt%)	Sulfur, Moisture and Ash (wt%)	[As-Received] (scf/ton)	[DAF] (scf/ton)	[DMMF] (scf/ton)
2.08	7.49	20.16	27.65	30.41	10.90	15.07	15.66







Well:	Ameren #1-24
Operator:	Peabody Natural Gas LLC
Location:	Jasper County/IL; NWc NW NW NW, Sec24-6N-8E
Field:	Newton Power Plant
Formation:	Pennsylvanian, Herrin Coal
Comments:	Coal seam is 1226 ft deep and 6.1 ft thick

Basic Information

Sample ID	Canister Number	Driller's Depth (feet)	As-Received Sample Weight (g)	DAF Sample Weight (g)	DMMF Sample Weight (g)	Measured Desorption (scm^3)	Sorption Time (hr) for 63.2% of Measured Desorption
Ameren#1-24 Herrin 2	E1	1227.3	1666	1430	1400	3768.4	477.5

Sorption Time (hr) for 63.2% of Total Gas
1467

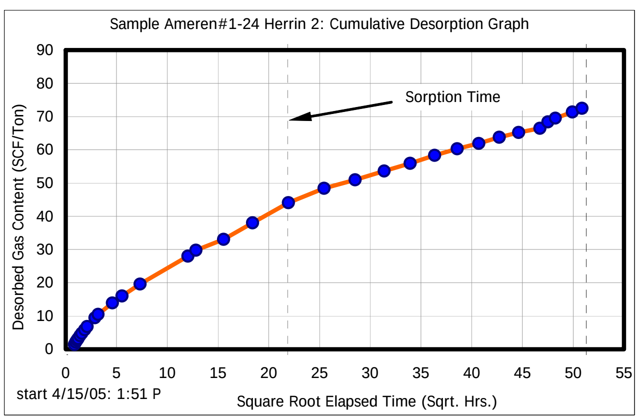
Lost Gas Volume

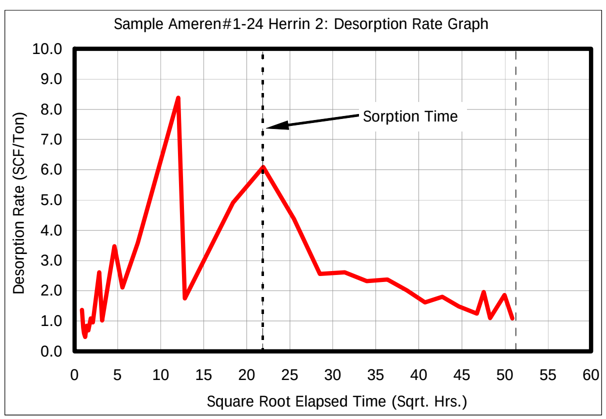
USBM			Smith and Williams	
(%)	(As-Received) (scf/ton)	(DMMF) (scf/ton)	(%)	(As-Received) (scf/ton)
3.7	2.8	3.3	2.0	1.5

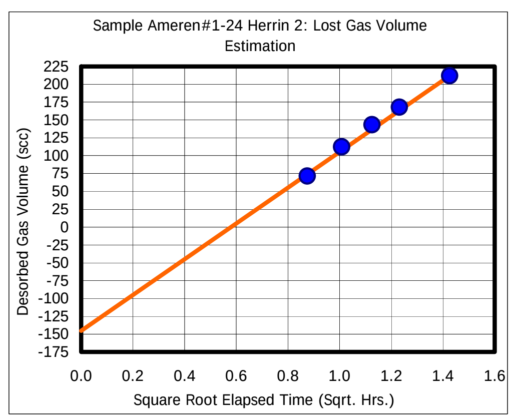
Total Gas Volume

USBM			Smith and Williams		
(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)	(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)
95.0	110.6	113.0	93.7	109.1	111.4

Other Components					Residual Gas Volume		
Sulfur (wt%)	Moisture (wt%)	Ash (wt%)	Moisture Plus Ash (wt%)	Sulfur, Moisture and Ash (wt%)	[As-Received] (scf/ton)	[DAF] (scf/ton)	[DMMF] (scf/ton)
2.31	7.91	6.27	14.18	15.95	19.70	22.96	23.44







Well:	Ameren #1-24
Operator:	Peabody Natural Gas LLC
Location:	Jasper County/IL; NWc NW NW NW, Sec24-6N-8E
Field:	Newton Power Plant
Formation:	Pennsylvanian, Herrin Coal
Comments:	Coal seam is 1226 ft deep and 6.1 ft thick

Basic Information

Sample ID	Canister Number	Driller's Depth (feet)	As-Received Sample Weight (g)	DAF Sample Weight (g)	DMMF Sample Weight (g)	Measured Desorption (scm^3)	Sorption Time (hr) for 63.2% of Measured Desorption
Ameren#1-24 Herrin 3	E2	1230.9	2012	1624	1551	4028.0	544.7

Sorption Time (hr) for 63.2% of Total Gas
1267

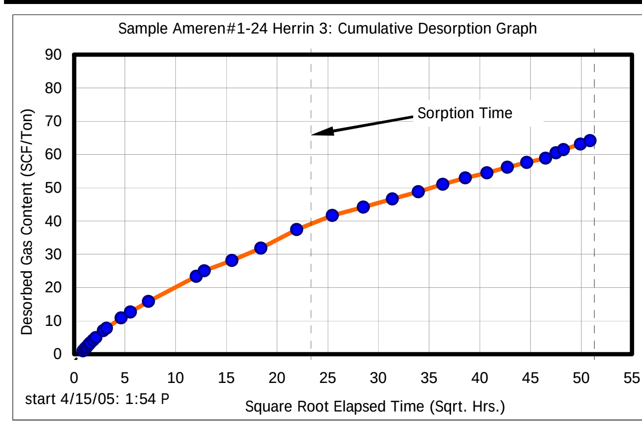
Lost Gas Volume

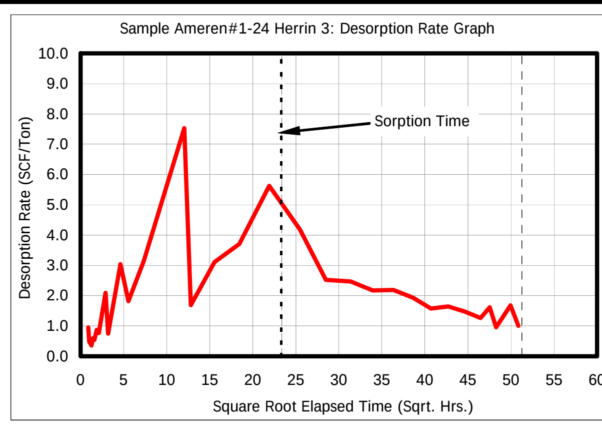
USBM			Smith and Williams	
(%)	(As-Received) (scf/ton)	(DMMF) (scf/ton)	(%)	(As-Received) (scf/ton)
3.2	2.1	2.8	1.9	1.3

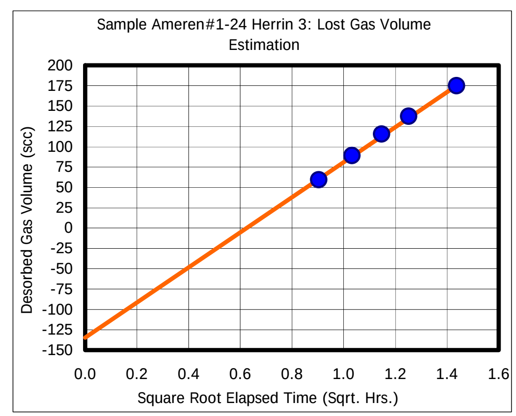
Total Gas Volume

USBM			Smith and Williams		
(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)	(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)
79.6	98.6	103.2	78.7	97.5	102.1

Other Components					Residual Gas Volume		
Sulfur (wt%)	Moisture (wt%)	Ash (wt%)	Moisture Plus Ash (wt%)	Sulfur, Moisture and Ash (wt%)	[As-Received] (scf/ton)	[DAF] (scf/ton)	[DMMF] (scf/ton)
4.93	8.05	11.25	19.30	22.91	13.30	16.48	17.25







Well:	Ameren #1-24
Operator:	Peabody Natural Gas LLC
Location:	Jasper County/IL; NWc NW NW NW, Sec24-6N-8E
Field:	Newton Power Plant
Formation:	Pennsylvanian, Briar Hill Coal
Comments:	Coal seam is 1257 ft deep and 3 ft thick

Basic Information

Sample ID	Canister Number	Driller's Depth (feet)	As-Received Sample Weight (g)	DAF Sample Weight (g)	DMMF Sample Weight (g)	Measured Desorption (scm^3)	Sorption Time (hr) for 63.2% of Measured Desorption
Ameren#1-24 Briar Hill	E4	1258.7	2037	1616	1552	3018.5	614.0

Sorption Time (hr) for 63.2% of Total Gas
2482

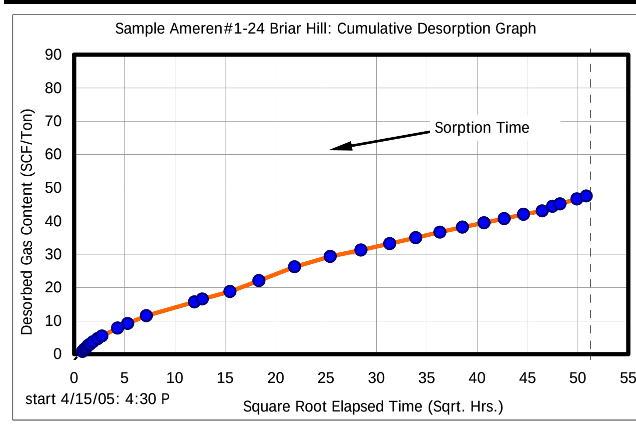
Lost Gas Volume

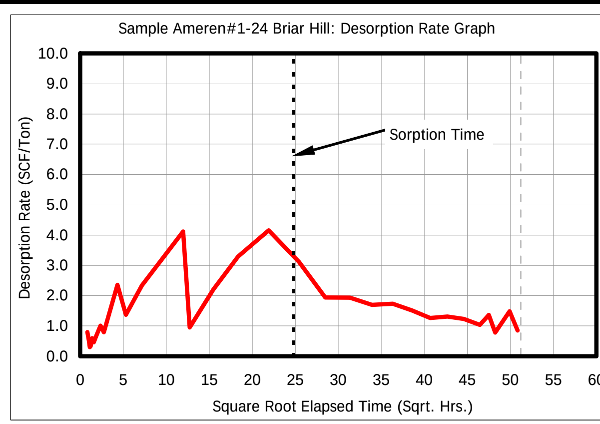
USBM			Smith and Williams	
(%)	(As-Received) (scf/ton)	(DMMF) (scf/ton)	(%)	(As-Received) (scf/ton)
3.7	1.8	2.4	1.5	0.7

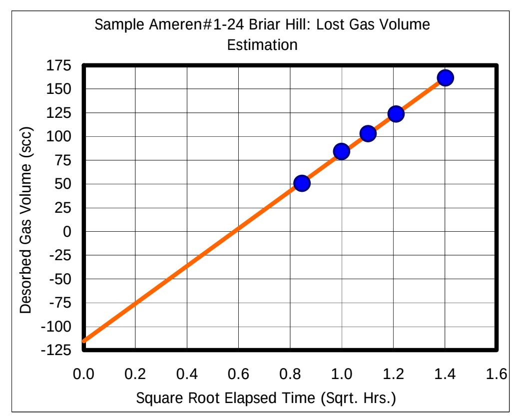
Total Gas Volume

USBM			Smith and Williams		
(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)	(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)
73.7	92.9	96.7	72.6	91.5	95.3

Other Components					Residual Gas Volume		
Sulfur (wt%)	Moisture (wt%)	Ash (wt%)	Moisture Plus Ash (wt%)	Sulfur, Moisture and Ash (wt%)	[As-Received] (scf/ton)	[DAF] (scf/ton)	[DMMF] (scf/ton)
3.70	6.84	13.80	20.64	23.78	24.40	30.75	32.01







Well:	Ameren #1-24
Operator:	Peabody Natural Gas LLC
Location:	Jasper County/IL; NWc NW NW NW, Sec24-6N-8E
Field:	Newton Power Plant
Formation:	Pennsylvanian, Shale X
Comments:	Shale is 1261 ft deep

Basic Information

Sample ID	Canister Number	Driller's Depth (feet)	As-Received Sample Weight (g)	DAF Sample Weight (g)	DMMF Sample Weight (g)	Measured Desorption (scm^3)	Sorption Time (hr) for 63.2% of Measured Desorption
Ameren#1-24 Shale X	E5	1261.8	3520	428	113	484.3	458.2

Sorption Time (hr) for 63.2% of Total Gas
460

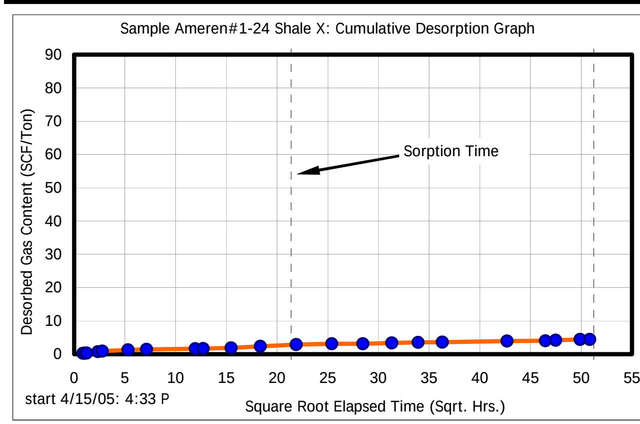
Lost Gas Volume

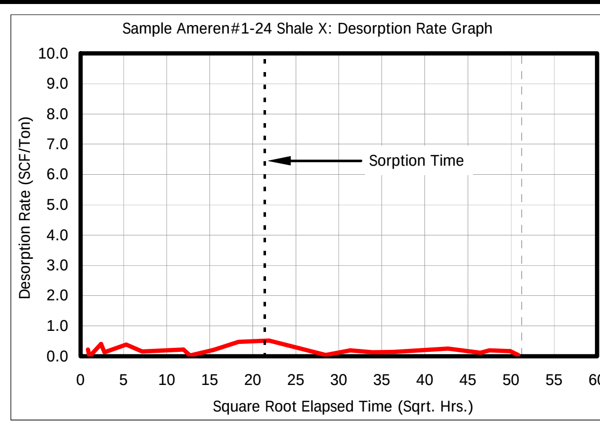
USBM			Smith and Williams	
(%)	(As-Received) (scf/ton)	(DMMF) (scf/ton)	(%)	(As-Received) (scf/ton)
0.0	0.0	0.0	2.6	0.1

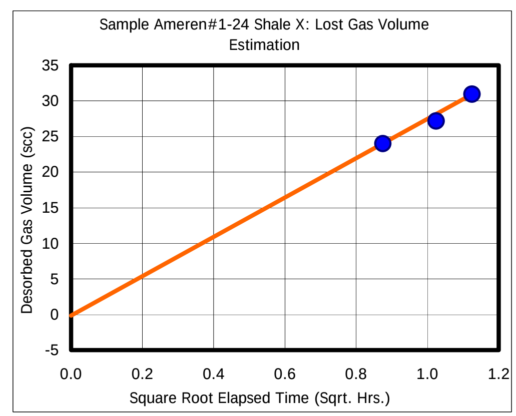
Total Gas Volume

USBM			Smith and Williams		
(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)	(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)
4.4	36.3	138.0	4.5	37.2	141.6

Other Components					Residual Gas Volume		
Sulfur (wt%)	Moisture (wt%)	Ash (wt%)	Moisture Plus Ash (wt%)	Sulfur, Moisture and Ash (wt%)	[As-Received] (scf/ton)	[DAF] (scf/ton)	[DMMF] (scf/ton)
4.19	4.60	83.24	87.84	96.80	0.00	0.00	0.00







Well:	Ameren #1-24
Operator:	Peabody Natural Gas LLC
Location:	Jasper County/IL; NWc NW NW NW, Sec24-6N-8E
Field:	Newton Power Plant
Formation:	Pennsylvanian, Springfield Coal
Comments:	Coal seam is 1268 ft deep and 2.0 ft thick

Basic Information

Sample ID	Canister Number	Driller's Depth (feet)	As-Received Sample Weight (g)	DAF Sample Weight (g)	DMMF Sample Weight (g)	Measured Desorption (scm^3)	Sorption Time (hr) for 63.2% of Measured Desorption
Ameren#1-24 Springfield	D1	1269.4	2062	1037	928	3481.7	191.0

Sorption Time (hr) for 63.2% of Total Gas
652

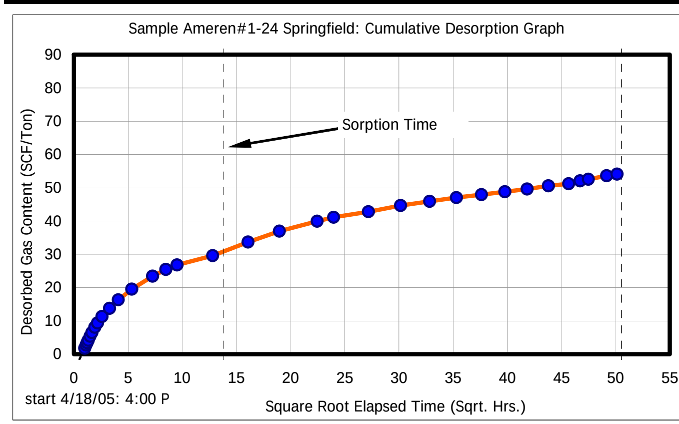
Lost Gas Volume

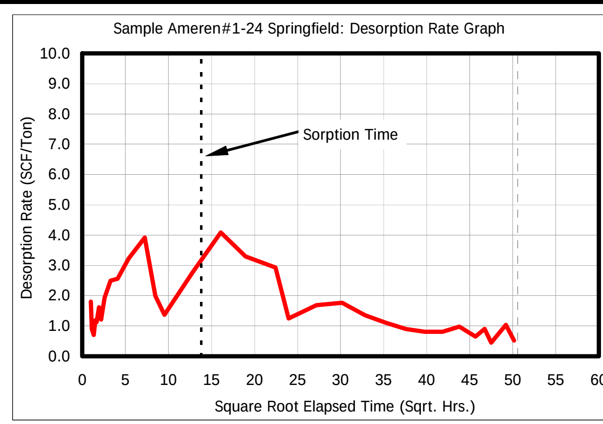
USBM			Smith and Williams	
(%)	(As-Received) (scf/ton)	(DMMF) (scf/ton)	(%)	(As-Received) (scf/ton)
8.9	5.3	11.8	4.7	2.7

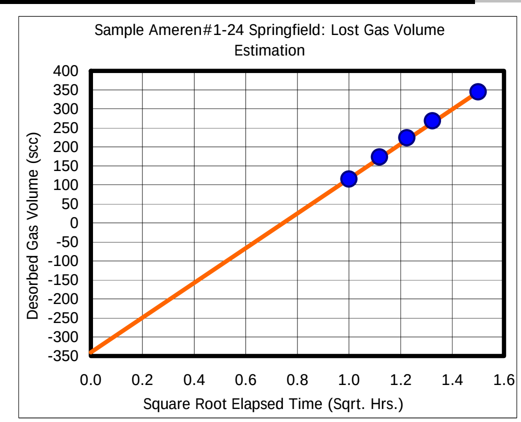
Total Gas Volume

USBM			Smith and Williams		
(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)	(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)
66.4	132.0	147.5	63.8	126.7	141.7

Other Components					Residual Gas Volume		
Sulfur (wt%)	Moisture (wt%)	Ash (wt%)	Moisture Plus Ash (wt%)	Sulfur, Moisture and Ash (wt%)	[As-Received] (scf/ton)	[DAF] (scf/ton)	[DMMF] (scf/ton)
3.75	9.11	40.58	49.69	55.00	7.00	13.91	15.56







Well:	Ameren #1-24
Operator:	Peabody Natural Gas LLC
Location:	Jasper County/IL; NWc NW NW NW, Sec24-6N-8E
Field:	Newton Power Plant
Formation:	Pennsylvanian, Excello Shale
Comments:	Shale is 1345 ft deep and 6.0 ft thick

Basic Information

Sample ID	Canister Number	Driller's Depth (feet)	As-Received Sample Weight (g)	DAF Sample Weight (g)	DMMF Sample Weight (g)	Measured Desorption (scm^3)	Sorption Time (hr) for 63.2% of Measured Desorption
Ameren#1-24 Excello Shale	D3	1347.3	2960	895	705	1695.1	844.9

Sorption Time (hr) for 63.2% of Total Gas
2109

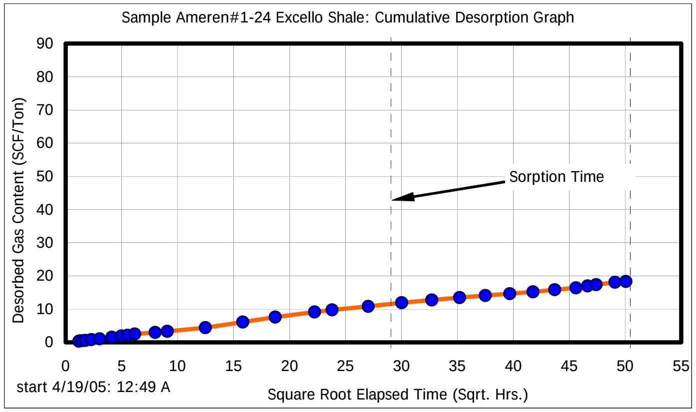
Lost Gas Volume

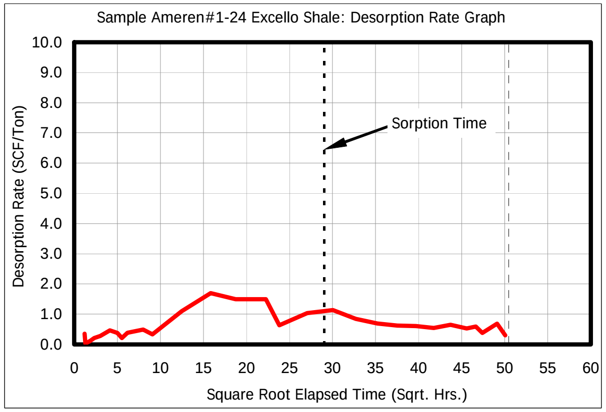
USBM			Smith and Williams	
(%)	(As-Received) (scf/ton)	(DMMF) (scf/ton)	(%)	(As-Received) (scf/ton)
0.3	0.1	0.3	1.2	0.2

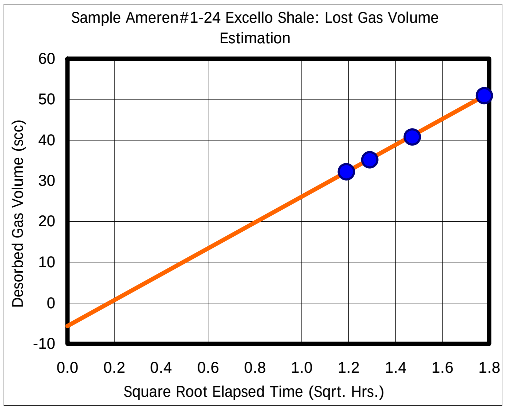
Total Gas Volume

USBM			Smith and Williams		
(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)	(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)
26.2	86.7	110.0	26.4	87.2	110.7

Other Components					Residual Gas Volume		
Sulfur (wt%)	Moisture (wt%)	Ash (wt%)	Moisture Plus Ash (wt%)	Sulfur, Moisture and Ash (wt%)	[As-Received] (scf/ton)	[DAF] (scf/ton)	[DMMF] (scf/ton)
2.11	4.15	65.62	69.77	76.18	7.80	25.80	32.75







Well:	Ameren #1-24
Operator:	Peabody Natural Gas LLC
Location:	Jasper County/IL; NWc NW NW NW, Sec24-6N-8E
Field:	Newton Power Plant
Formation:	Pennsylvanian, Houchin Creek Coal
Comments:	Coal seam is 1348 ft deep and 2.0 ft thick

Basic Information

Sample ID	Canister Number	Driller's Depth (feet)	As-Received Sample Weight (g)	DAF Sample Weight (g)	DMMF Sample Weight (g)	Measured Desorption (scm^3)	Sorption Time (hr) for 63.2% of Measured Desorption
Ameren#1-24 Houchin Creek	D2	1349	2278	1510	1266	2965.9	512.6

Sorption Time (hr) for 63.2% of Total Gas
1850

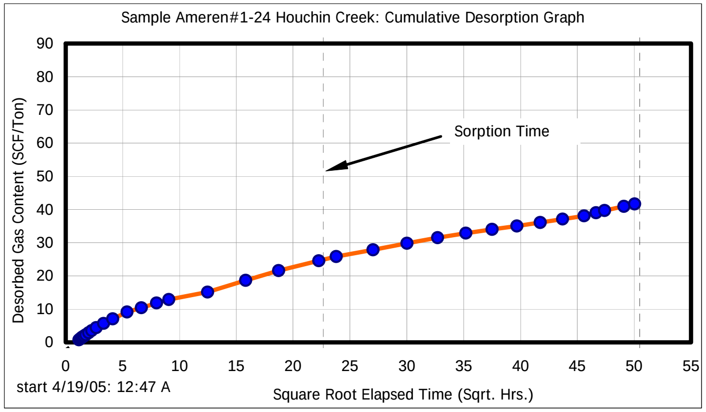
Lost Gas Volume

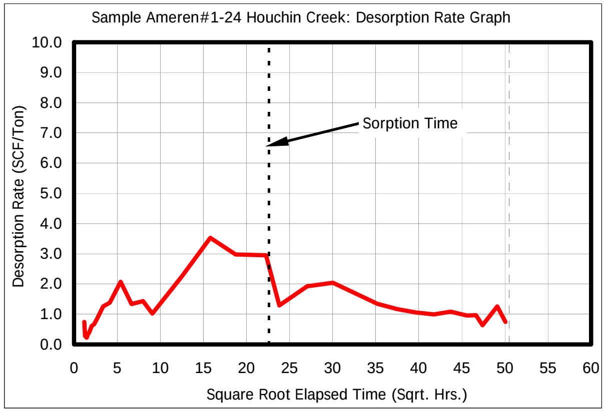
USBM			Smith and Williams	
(%)	(As-Received) (scf/ton)	(DMMF) (scf/ton)	(%)	(As-Received) (scf/ton)
5.0	2.2	3.9	2.6	1.1

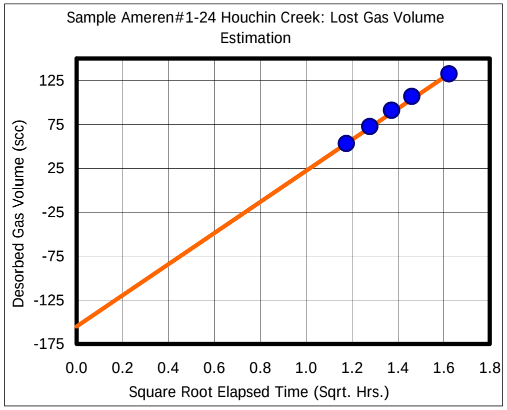
Total Gas Volume

USBM			Smith and Williams		
(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)	(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)
58.2	87.8	104.7	57.1	86.1	102.8

Other Components					Residual Gas Volume		
Sulfur (wt%)	Moisture (wt%)	Ash (wt%)	Moisture Plus Ash (wt%)	Sulfur, Moisture and Ash (wt%)	[As-Received] (scf/ton)	[DAF] (scf/ton)	[DMMF] (scf/ton)
15.45	5.63	28.07	33.70	44.44	14.30	21.57	25.74







Well:	Ameren #1-24
Operator:	Peabody Natural Gas LLC
Location:	Jasper County/IL; NWc NW NW NW, Sec24-6N-8E
Field:	Newton Power Plant
Formation:	Pennsylvanian, Survant Coal
Comments:	Coal is 1423 ft deep and 2.0 ft thick

Basic Information

Sample ID	Canister Number	Driller's Depth (feet)	As-Received Sample Weight (g)	DAF Sample Weight (g)	DMMF Sample Weight (g)	Measured Desorption (scm^3)	Sorption Time (hr) for 63.2% of Measured Desorption
Ameren#1-24 Survant	D4	1423.6	1714	1409	1391	4555.7	452.9

Sorption Time (hr) for 63.2% of Total Gas
1031

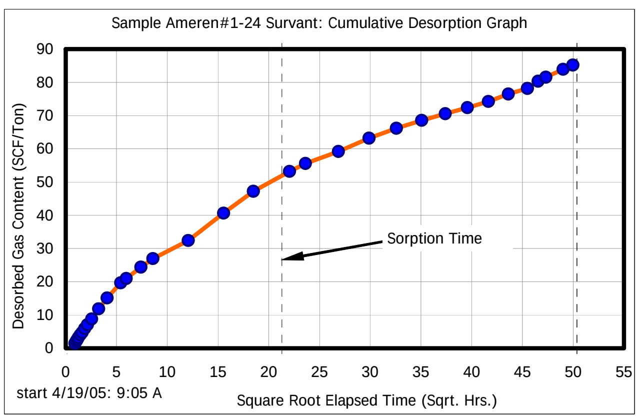
Lost Gas Volume

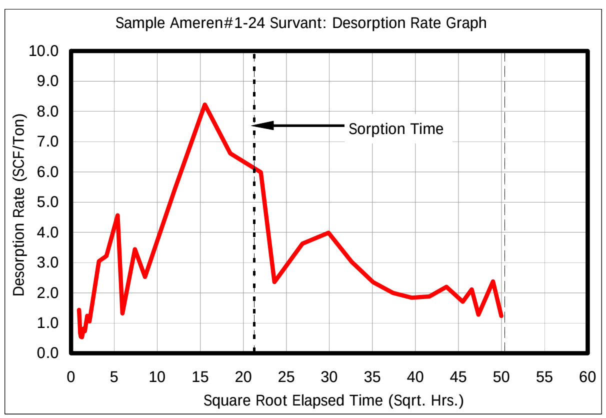
USBM			Smith and Williams	
(%)	(As-Received) (scf/ton)	(DMMF) (scf/ton)	(%)	(As-Received) (scf/ton)
3.3	2.9	3.6	2.1	1.8

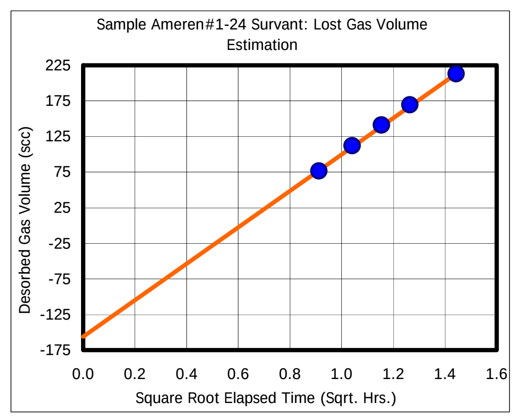
Total Gas Volume

USBM			Smith and Williams		
(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)	(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)
103.9	126.3	128.0	102.8	125.0	126.7

Other Components					Residual Gas Volume		
Sulfur (wt%)	Moisture (wt%)	Ash (wt%)	Moisture Plus Ash (wt%)	Sulfur, Moisture and Ash (wt%)	[As-Received] (scf/ton)	[DAF] (scf/ton)	[DMMF] (scf/ton)
0.70	9.07	8.69	17.76	18.84	15.80	19.21	19.47







Well:	Ameren #1-24
Operator:	Peabody Natural Gas LLC
Location:	Jasper County/IL; NWc NW NW NW, Sec24-6N-8E
Field:	Newton Power Plant
Formation:	Pennsylvanian, Shale above U. Dekoven
Comments:	Shale is 1484 ft deep

Basic Information

Sample ID	Canister Number	Driller's Depth (feet)	As-Received Sample Weight (g)	DAF Sample Weight (g)	DMMF Sample Weight (g)	Measured Desorption (scm^3)	Sorption Time (hr) for 63.2% of Measured Desorption
Ameren#1-24 Shale Y	C2	1484.9	2981	886	677	2742.8	611.8

Sorption Time (hr) for 63.2% of Total Gas
1487

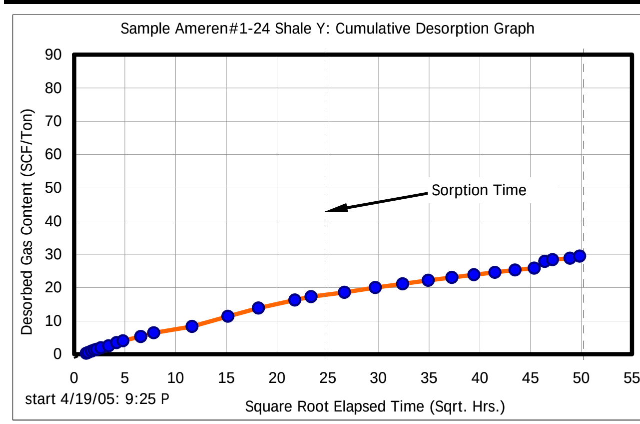
Lost Gas Volume

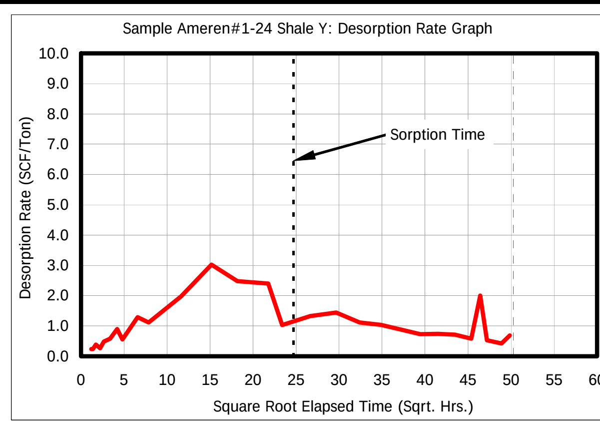
USBM			Smith and Williams	
(%)	(As-Received) (scf/ton)	(DMMF) (scf/ton)	(%)	(As-Received) (scf/ton)
4.0	1.2	5.4	1.9	0.6

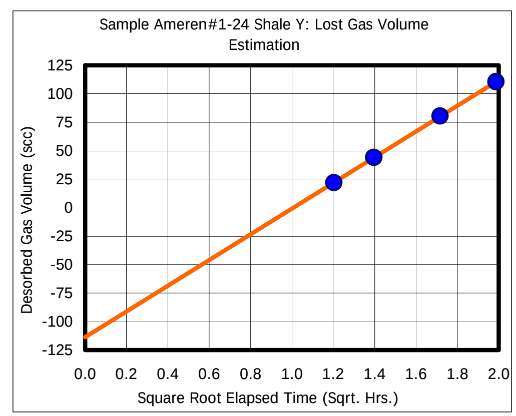
Total Gas Volume

USBM			Smith and Williams		
(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)	(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)
37.2	125.2	163.8	36.6	123.0	161.0

Other Components					Residual Gas Volume		
Sulfur (wt%)	Moisture (wt%)	Ash (wt%)	Moisture Plus Ash (wt%)	Sulfur, Moisture and Ash (wt%)	[As-Received] (scf/ton)	[DAF] (scf/ton)	[DMMF] (scf/ton)
3.08	3.75	66.53	70.28	77.30	6.50	21.87	28.63







Well:	Ameren #1-24
Operator:	Peabody Natural Gas LLC
Location:	Jasper County/IL; NWc NW NW NW, Sec24-6N-8E
Field:	Newton Power Plant
Formation:	Pennsylvanian, Upper Dekoven Coal
Comments:	Coal is 1486 ft deep and 3.0 ft thick

Basic Information

Sample ID	Canister Number	Driller's Depth (feet)	As-Received Sample Weight (g)	DAF Sample Weight (g)	DMMF Sample Weight (g)	Measured Desorption (scm^3)	Sorption Time (hr) for 63.2% of Measured Desorption
Ameren#1-24 U. Dekoven	C1	1486.3	1820	1370	1319	3694.0	424.9

Lost Gas Volume

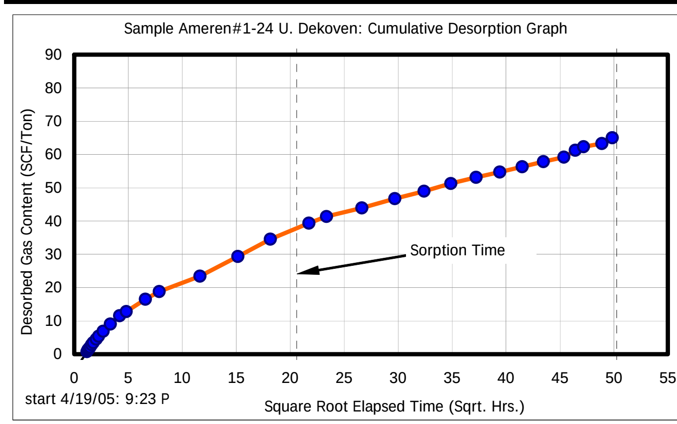
USBM			Smith and Williams	
(%)	(As-Received) (scf/ton)	(DMMF) (scf/ton)	(%)	(As-Received) (scf/ton)
7.3	5.1	7.0	2.6	1.7

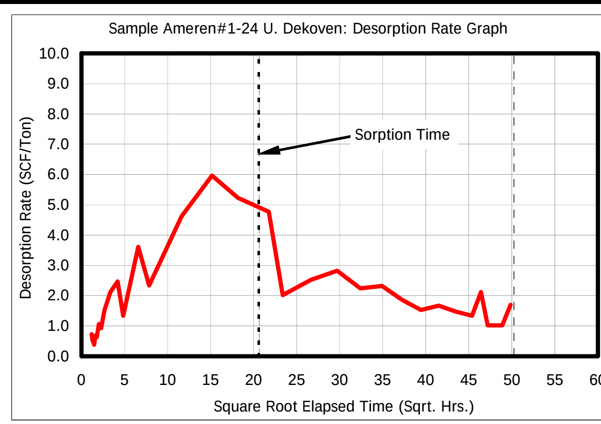
Sorption Time (hr) for 63.2% of Total Gas
1522

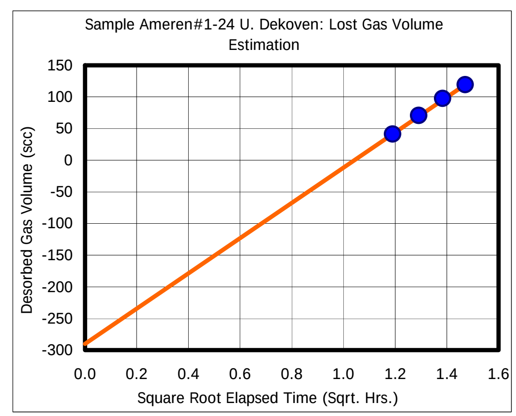
Total Gas Volume

USBM			Smith and Williams		
(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)	(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)
86.1	114.4	118.8	82.8	109.9	114.2

Other Components					Residual Gas Volume		
Sulfur (wt%)	Moisture (wt%)	Ash (wt%)	Moisture Plus Ash (wt%)	Sulfur, Moisture and Ash (wt%)	[As-Received] (scf/ton)	[DAF] (scf/ton)	[DMMF] (scf/ton)
2.33	5.62	19.11	24.73	27.54	16.00	21.26	22.08







Well:	Ameren #1-24
Operator:	Peabody Natural Gas LLC
Location:	Jasper County/IL; NWc NW NW NW, Sec24-6N-8E
Field:	Newton Power Plant
Formation:	Pennsylvanian, Lower Dekoven Coal
Comments:	Coal is 1491 ft deep and 1.0 ft thick

Basic Information

Sample ID	Canister Number	Driller's Depth (feet)	As-Received Sample Weight (g)	DAF Sample Weight (g)	DMMF Sample Weight (g)	Measured Desorption (scm^3)	Sorption Time (hr) for 63.2% of Measured Desorption
Ameren#1-24 L. Dekoven	D5	1491.2	1668	770	659	1800.3	719.3

Sorption Time (hr) for 63.2% of Total Gas
1638

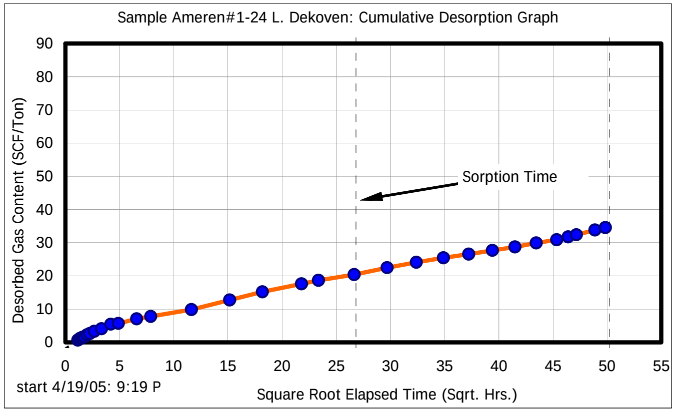
Lost Gas Volume

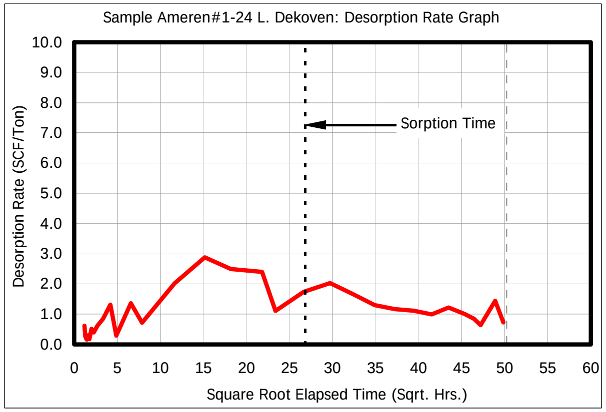
USBM			Smith and Williams	
(%)	(As-Received) (scf/ton)	(DMMF) (scf/ton)	(%)	(As-Received) (scf/ton)
5.5	2.0	5.1	1.9	0.7

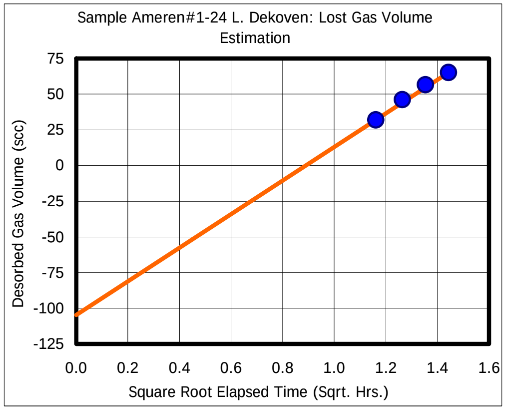
Total Gas Volume

USBM			Smith and Williams		
(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)	(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)
44.6	96.6	112.9	43.3	93.7	109.5

Other Components					Residual Gas Volume		
Sulfur (wt%)	Moisture (wt%)	Ash (wt%)	Moisture Plus Ash (wt%)	Sulfur, Moisture and Ash (wt%)	[As-Received] (scf/ton)	[DAF] (scf/ton)	[DMMF] (scf/ton)
4.86	3.85	49.98	53.83	60.50	8.00	17.33	20.25







Well:	Ameren #1-24
Operator:	Peabody Natural Gas LLC
Location:	Jasper County/IL; NWc NW NW NW, Sec24-6N-8E
Field:	Newton Power Plant
Formation:	Pennsylvanian, Seelyville Coal
Comments:	Coal seam is 1496 ft deep and 7.0 ft thick

Basic Information

Sample ID	Canister Number	Driller's Depth (feet)	As-Received Sample Weight (g)	DAF Sample Weight (g)	DMMF Sample Weight (g)	Measured Desorption (scm^3)	Sorption Time (hr) for 63.2% of Measured Desorption
Ameren#1-24 Seelyville 1	C3	1497	1995	1623	1553	5005.6	462.2

Sorption Time (hr) for 63.2% of Total Gas
1583

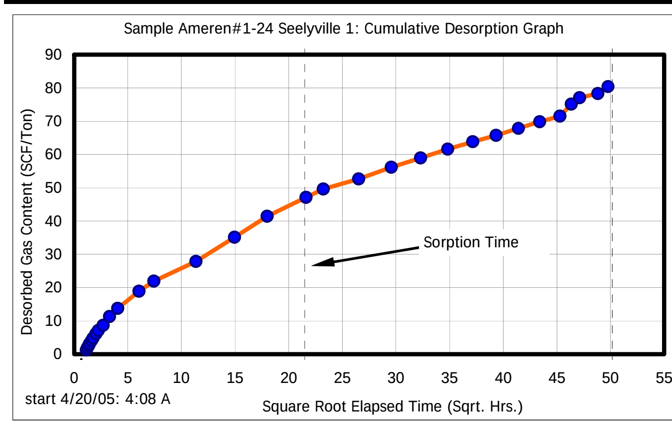
Lost Gas Volume

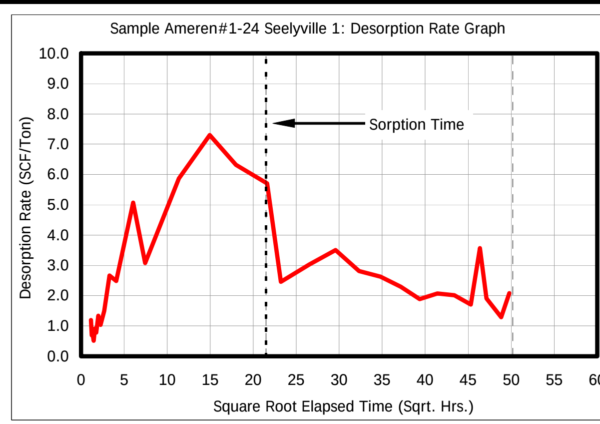
USBM			Smith and Williams	
(%)	(As-Received) (scf/ton)	(DMMF) (scf/ton)	(%)	(As-Received) (scf/ton)
6.8	5.9	7.5	2.4	2.0

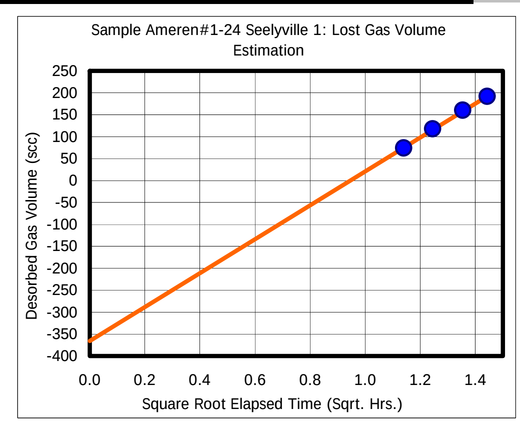
Total Gas Volume

USBM			Smith and Williams		
(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)	(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)
104.7	128.6	134.4	100.8	123.9	129.4

Other Components					Residual Gas Volume		
Sulfur (wt%)	Moisture (wt%)	Ash (wt%)	Moisture Plus Ash (wt%)	Sulfur, Moisture and Ash (wt%)	[As-Received] (scf/ton)	[DAF] (scf/ton)	[DMMF] (scf/ton)
4.50	5.74	12.90	18.64	22.15	18.40	22.62	23.63







Well:	Ameren #1-24
Operator:	Peabody Natural Gas LLC
Location:	Jasper County/IL; NWc NW NW NW, Sec24-6N-8E
Field:	Newton Power Plant
Formation:	Pennsylvanian, Seelyville Coal
Comments:	Coal seam is 1496 ft deep and 7.0 ft thick

Basic Information

Sample ID	Canister Number	Driller's Depth (feet)	As-Received Sample Weight (g)	DAF Sample Weight (g)	DMMF Sample Weight (g)	Measured Desorption (scm^3)	Sorption Time (hr) for 63.2% of Measured Desorption
Ameren#1-24 Seelyville 2	C4	1498.1	2103	1652	1560	5142.3	398.3

Sorption Time (hr) for 63.2% of Total Gas
1422

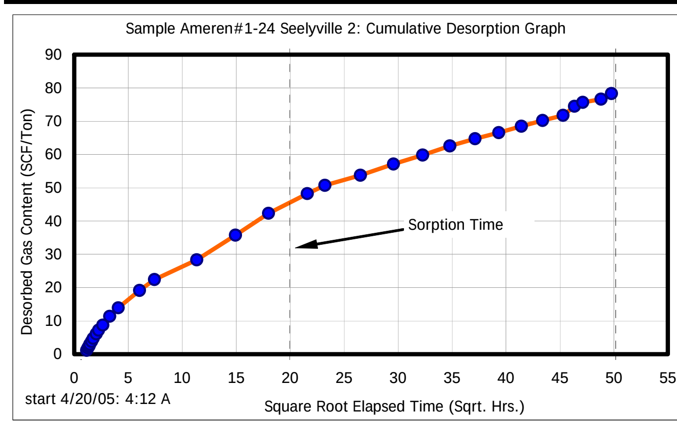
Lost Gas Volume

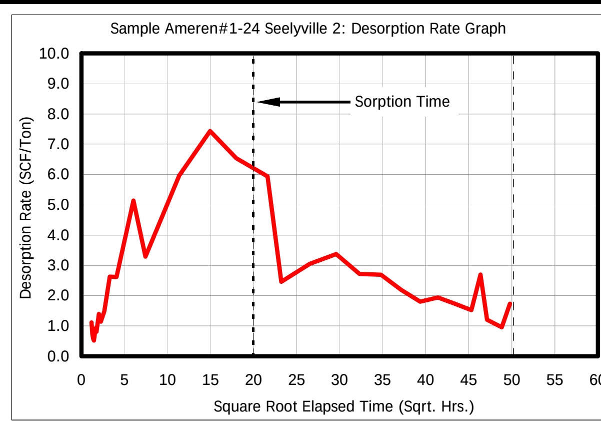
USBM			Smith and Williams	
(%)	(As-Received) (scf/ton)	(DMMF) (scf/ton)	(%)	(As-Received) (scf/ton)
7.4	6.2	8.4	2.7	2.1

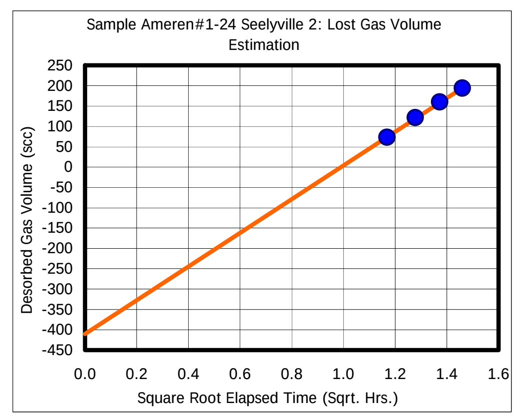
Total Gas Volume

USBM			Smith and Williams		
(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)	(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)
103.2	131.3	139.1	99.1	126.1	133.6

Other Components					Residual Gas Volume		
Sulfur (wt%)	Moisture (wt%)	Ash (wt%)	Moisture Plus Ash (wt%)	Sulfur, Moisture and Ash (wt%)	[As-Received] (scf/ton)	[DAF] (scf/ton)	[DMMF] (scf/ton)
5.67	5.50	15.94	21.44	25.83	18.60	23.68	25.08







Well:	Ameren #1-24
Operator:	Peabody Natural Gas LLC
Location:	Jasper County/IL; NWc NW NW NW, Sec24-6N-8E
Field:	Newton Power Plant
Formation:	Pennsylvanian, Seelyville Coal
Comments:	Coal seam is 1496 ft deep and 7.0 ft thick

Basic Information

Sample ID	Canister Number	Driller's Depth (feet)	As-Received Sample Weight (g)	DAF Sample Weight (g)	DMMF Sample Weight (g)	Measured Desorption (scm^3)	Sorption Time (hr) for 63.2% of Measured Desorption
Ameren#1-24 Seelyville 3	C5	1500.3	1825	1525	1454	5487.5	318.2

Sorption Time (hr) for 63.2% of Total Gas
1270

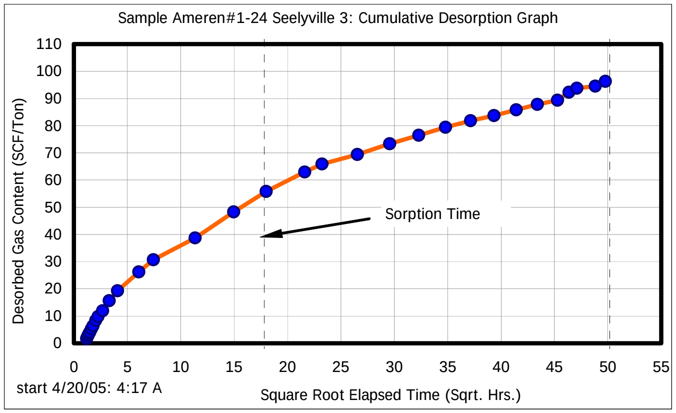
Lost Gas Volume

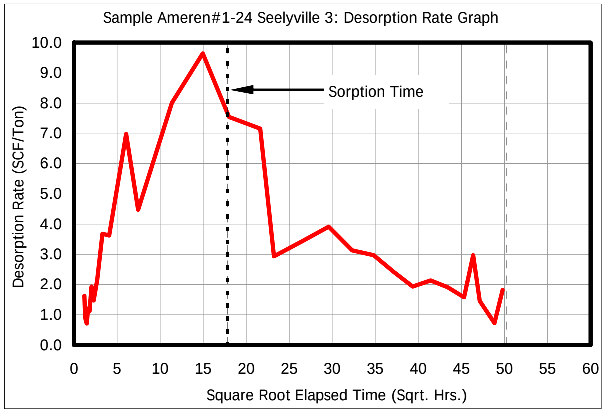
USBM			Smith and Williams	
(%)	(As-Received) (scf/ton)	(DMMF) (scf/ton)	(%)	(As-Received) (scf/ton)
8.0	8.4	10.5	3.3	3.3

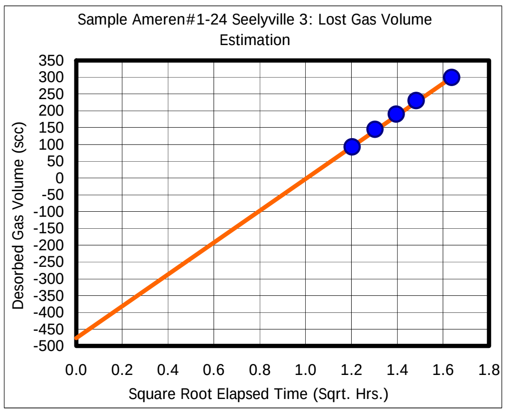
Total Gas Volume

USBM			Smith and Williams		
(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)	(As-Received) (scf/ton)	(DAF) (scf/ton)	(DMMF) (scf/ton)
127.0	152.0	159.4	121.9	145.9	153.0

Other Components					Residual Gas Volume		
Sulfur (wt%)	Moisture (wt%)	Ash (wt%)	Moisture Plus Ash (wt%)	Sulfur, Moisture and Ash (wt%)	[As-Received] (scf/ton)	[DAF] (scf/ton)	[DMMF] (scf/ton)
5.63	6.43	10.01	16.44	20.34	22.30	26.69	27.99







Appendix 5a. Pressure Transient Testing for Hon #9 by Pinnacle Technologies

15579 E. Hinsdale Circle
Suite 102
Centennial, CO 80112
Ph: 720-344-3464
Fax: 303-766-4306
www.pinntech.com

Injection Falloff Test Results For Royal Drilling & Producing Hon #9 CBM Test Well White County, Illinois Final Report

Submitted to:

Royal Drilling & Producing
Crossville, Illinois
&
Illinois State Geological Survey
Champaign, Illinois

May 2004

Houston 281-876-2323
San Francisco 415-861-1097
Bakersfield 661-335-7711
Denver 720-344-3464
Delft 31-15-219-0062
Reynosa 52-892-42191
Calgary 403-863-8458

Pinnacle

<u>Hon #9 Injection/Falloff Test Results</u>

Table of Contents

Executive Summary

Pinnacle Technologies, Inc. (Pinnacle), conducted six injection falloff tests in a wellbore located in White County, Illinois for Royal Drilling & Producing, Inc. This report discusses the work performed in the Hon #9 wellbore. The purpose of the work was to determine in-situ permeability to water in multiple coal seam intervals.

Pinnacle used its Kansas based injection/falloff PermPT equipment to perform the tests. The injection unit is capable of very low rate – high-pressure injection necessary for injection falloff testing in coal seams. Bottom hole pressure measurement was used for all tests performed, with surface injection rates measured at the injection unit. Fracture gradients of 1.09 psi/ft to 2.09 psi/ft based on breakdowns conducted prior to each injection test were used to determine maximum surface injection pressures.

Test Results:
Six coal seams were tested in this wellbore. Results of the injection/falloff testing in Hon #9 wellbore are as follows:

Test Name	Perforated Interval (ft)	Net Pay (ft)	Permeability (mD)	Transmissivity (mD·ft/cp)	Skin Factor (Dimensionless)	Average Pressure (psi)
Test 1	1109-1116	5	14.1	71.9	-0.3	496
Test 2	1066-68	2	5.2	10.6	-3.4	516
Test 3	996-1000	4	3.3	13.1	-5.0	440
Test 4	882-886	4	21.7	83.0	-1.8	681
Test 5	805-810	5	4.3	20.4	-4.9	510
Test 6	759-761	2	33.7	63.0	NA	328

The first injection/falloff test was conducted in two coal seams having a combined perforated thickness of 5 ft. For the permeability test, fresh water was injected for 4.0 hours at an average rate of 2.63 gallons per minute and surface injection pressure of 692 psi. The well was shut-in downhole with a mechanical in-line ball valve and allowed to falloff for 23.8 hours

Using 5.0 ft of net pay, analysis of the pressure falloff data with a single-phase pressure transient analysis program resulted in coal seam permeability to water of 14.1 mD. The calculated skin was –0.3 and radius of investigation was estimated at 443 ft.

The second injection/falloff test was conducted in a coal seam having a perforated thickness of 2 ft. For the permeability test, fresh water was injected for 4.0 hours at an average rate of 1.22 gallons per minute and surface injection pressure of 1,131 psi. The well was shut-in downhole with a mechanical in-line ball valve and allowed to falloff for 16.0 hours

Using 2.0 ft of net pay, analysis of the pressure falloff data with a single-phase pressure transient analysis program resulted in coal seam permeability to water of 5.2 mD. The calculated skin was –3.4 and radius of investigation was estimated at 120 ft.

The third injection/falloff test was conducted in a coal seam having a perforated thickness of 4 ft. For the permeability test, fresh water was injected for 4.0 hours at an average rate of 0.30 gallons per minute and surface injection pressure of 731 psi. The well was shut-in downhole with a mechanical in-line ball valve and allowed to falloff for 11.2 hours. While actuating the in-line downhole ball valve, the packer was released. Despite this compromise of downhole pressure integrity, the test still provided adequate data for analysis.

Using 4.0 ft of net pay, analysis of the pressure falloff data with a single-phase pressure transient analysis program resulted in coal seam permeability to water of 3.3 mD. The calculated skin was –5.0 and radius of investigation was estimated at 189 ft.

The fourth injection/falloff test was conducted in a coal seam having a perforated thickness of 4 ft. For the permeability test, fresh water was injected for 4.0 hours at an average rate of 1.07 gallons per minute and surface injection pressure of 778 psi. The well was shut-in downhole with a mechanical in-line ball valve and allowed to falloff for 17.4 hours.

Using 4.0 ft of net pay, analysis of the pressure falloff data with a single-phase pressure transient analysis program resulted in coal seam permeability to water of 21.7 mD. The calculated skin was –1.8 and radius of investigation was estimated at 498 ft.

The fifth injection/falloff test was conducted in a coal seam having a perforated thickness of 5 ft. For the permeability test, fresh water was injected for 4.0 hours at an average rate of 1.67 gallons per minute and surface injection pressure of 901 psi. The well was shut-in downhole with a mechanical in-line ball valve and allowed to falloff for 16.8 hours.

Using 5.0 ft of net pay, analysis of the pressure falloff data with a single-phase pressure transient analysis program resulted in coal seam permeability to water of 4.3 mD. The calculated skin was –4.9 and radius of investigation was estimated at 219 ft.

The sixth and final injection/falloff test was conducted in a coal seam having a perforated thickness of 2 ft. For the permeability test, fresh water was injected for 4.0 hours at an average rate of 1.13 gallons per minute and surface injection pressure of 692 psi. The well was shut-in downhole with a mechanical in-line ball valve and allowed to falloff for 17.8 hours.

Because of difficulties establishing injectivity into the perforated interval, pressure during the injection phase of the test was steadily increased until the interval was essentially hydraulic fractured. This dictated the use of the "After-Closure Pseudo-Radial Flow Analysis Method" to ascertain reservoir permeability and average pressure. Details of this methodology are discussed in the Appendix.

Using 2.0 ft of net pay, analysis of the pressure falloff data with an After-Closure Pseudo-Radial Flow Analysis resulted in coal seam permeability to water of 34.4 mD. Near-wellbore damage or skin cannot be determined from this analysis method. The radius of investigation was estimated at 650 ft.

Background

The Illinois State Geological Survey and Royal Drilling & Producing, Inc. contracted Pinnacle Technologies to test the in-situ permeability in multiple coal seams in the Hon #9 wellbore near the town of Grayville, Illinois. Pinnacle Technologies supplied the pumping equipment, rate and pressure measurement, and personnel required for testing. Contractors for Royal Drilling & Producing conducted all other work beyond the injection/falloff testing.

Reservoir parameters used for the Hon #9 in all data analyses are outlined below in the following table.

Pertinent Reservoir Data

Parameter	**Perm Test #1**	**Perm Test #2**	**Perm Test #3**	**Perm Test #4**	**Perm Test #5**	**Perm Test #6**
Perforated Thickness, ft	5	2	4	4	5	
Depth to Coal Seam, ft	1109	1066	996	882	805	759
Mid Depth of Coal, ft	1112.5	1067.5	998	884	807.5	760
Skin Factor, dimensionless	-0.3	-3.4	-5.0	-1.8	-4.9	NA
Water Density, lb/ft^3	62.4	62.4	62.4	62.4	62.4	62.4
Tubing I.D., inches	1.995	1.995	1.995	1.995	1.995	1.995
Tubing Capacity, gal/ft	0.1624	0.1624	0.1624	0.1624	0.1624	0.1624
Casing I.D., inches	4.950	4.950	4.950	4.950	4.950	4.950
Casing Capacity, gal/ft	0.9997	0.9997	0.9997	0.9997	0.9997	0.9997
Water Viscosity, cp	0.977	0.991	1.014	1.045	1.061	1.070
Water Formation Volume,	1.02	1.02	1.02	1.02	1.02	1.02
Coal Porosity, %	1.5	1.5	1.5	1.5	1.5	1.5
Water Compressibility, psi^{-1}	3.6 e^{-6}	3.6 e^{-6}	3.6 e^{-6}	3.6 e^{-6}	3.6 e^{-6}	3.6 e^{-6}
Wellbore Radius, ft	0.2760	0.2760	0.2760	0.2760	0.2760	0.2760

Field Operations Summary

- Arrive on location and spot PermPT equipment. Conduct safety meeting and review job procedures and expectations with all personnel on location.
- Nipple up wellhead connections, pressure test surface injection lines to 2,000 psi. Inject into perforations for 5 minutes then cease pumping. Record breakdown pressure (if no breakdown noted, continue pumping), ISIP, and 60-minute falloff data. Calculate pertinent injection test parameters based on the breakdown data. If no breakdown noted, continue with next step.
- Inject into the target coal seam for at least 4 hours and record surface injection rates and injection pressures.
- Shut-in well downhole for minimum of 16 hours by rotating the tubing to actuate the in-line ball valve located in tubing string above the packer. Disconnect PermPT equipment following conclusion of injection portion of test.
- Nipple down wellhead connections and prepare to test next coal interval after moving bridge plug/packer downhole assembly.
- Nipple up wellhead and repeat test procedures. Repeat perforating, bridge plug/packer setting, breakdown, and injection/falloff procedures for all target intervals.
- Nipple down wellhead assembly and demobilize PermPT equipment. Clean up and secure location for future completion work.

Test Results Summary

Test #1

Date Tested:	May 4, 2004
Perforations:	1,109-11 ft & 1,113-16 ft
Surface Breakdown Pressure:	730 psi
Estimated Reservoir Pressure:	496 psi
Radius of Investigation:	442.6 ft
Reservoir Permeability ***(to water)***:	14.1 (5.0 ft net pay)
Transmissivity:	71.9 mD·ft/cp
Skin Factor:	-0.3

Test Comments: Test conducted with no complications.

Test #2

Date Tested:	May 5, 2004
Perforations:	1,066-68 ft
Surface Breakdown Pressure:	2,000 psi
Estimated Reservoir Pressure:	516 psi
Radius of Investigation:	120.0 ft
Reservoir Permeability ***(to water)***:	5.2 (2.0 ft net pay)
Transmissivity:	10.6 mD·ft/cp
Skin Factor:	-3.4

Test Comments: Test conducted with no complications.

Test #3

Date Tested:	May 6, 2004
Perforations:	996-1,000 ft
Surface Breakdown Pressure:	1,450 psi
Estimated Reservoir Pressure:	440 psi
Radius of Investigation:	189.2 ft
Reservoir Permeability ***(to water)***:	3.3 mD (4.0 ft net pay)
Transmissivity:	13.1 mD·ft/cp
Skin Factor:	-5.0

Test Comments: Packer accidentally released while shutting in the well – data still able to be analyzed, however.

Test #4

Date Tested:	May 7, 2004
Perforations:	882-86 ft
Surface Breakdown Pressure:	1,450 psi
Estimated Reservoir Pressure:	681 psi
Radius of Investigation:	497.6 ft
Reservoir Permeability ***(to water)***:	21.7 mD (4.0 ft net pay)
Transmissivity:	83.0 mD·ft/cp
Skin Factor:	-1.8

Test Comments: Test conducted with no complications.

Test #5

Date Tested:	May 8, 2004
Perforations:	805-10 ft
Surface Breakdown Pressure:	1,015 psi
Estimated Reservoir Pressure:	510 psi
Radius of Investigation:	218.7 ft
Reservoir Permeability ***(to water)***:	4.3 mD (5.0 ft net pay)

Transmissivity:	20.4 mD·ft/cp
Skin Factor:	-4.9

Test Comments: Test conducted with no complications.

Test #6

Date Tested:	May 9, 2004
Perforations:	759-61 ft
Surface Breakdown Pressure:	865 psi
Estimated Reservoir Pressure:	328 psi
Radius of Investigation:	650 ft
Reservoir Permeability ***(to water)***:	34.4 mD (2.0 ft net pay)
Transmissivity:	63.0 mD·ft/cp
Skin Factor:	NA

Test Comments: Test analyzed with after-closure, pseudo-radial method.

Conclusions

1. All tests conducted in the Hon #9 wellbore produced good quality data for analysis. The first five tests were pumped below fracturing pressures and were analyzed using conventional pressure transient testing solutions. The sixth and final test was conducted above fracturing pressure and was analyzed using an after-closure, pseudo-radial analysis solution.

2. All six tests yielded potentially commercial kh values in the target coal seams. However, hydraulic fracturing may be required for economic production. The measured permeabilities are likely pressure dependent and placing proppant in the near-wellbore region will aid in retaining a connection to the far-field reservoir.

3. In three of the six tested intervals, average reservoir pressure estimates are near that of a fresh water gradient (0.43 psi/ft). One interval is slightly higher than a fresh water gradient and two tests are significantly above a fresh water gradient. Reservoir pressure estimates significantly above that of normal hydrostatic gradients usually signify limited reservoir area.

4. All tests exhibited a negative skin or near-wellbore damage factor. This suggests that the face cleat system is, at least in the near-wellbore area, sufficiently connected to the well. The far-field permeability system may not be well connected or far-reaching, however, as indicated by both the inflated reservoir pressure estimates and overall permeability calculations.

Injection Testing Recommendations

1. Continued testing throughout the development of this project will aid in optimizing completions and help focus on the commercial coal intervals.

2. Conduct permeability testing on select seams throughout the development phase of the field in order to optimize completion practices. Additionally, permeability testing can help define optimum well spacing in the field.

3. Following completion of the wells and sufficient production testing, pressure transient testing should again be conducted to ascertain effective reservoir permeability after dewatering.

APPENDIX: Estimating Permeability using Diagnostic Injections

Reservoir permeability (or permeability-thickness production, kh) is the most important parameter for optimizing fracture designs and subsequently evaluating fracture performance. Unfortunately, for most fracture treatments permeability is only vaguely understood and the absence of good permeability data many times results in less-than-optimum treatment designs and unreliable interpretations of fracture performance. Pressure buildup (PBU) tests are the most reliable method of determining reservoir permeability, but these tests are often difficult to properly conduct, time consuming, and expensive. As a result, PBU tests are not routine in most fracturing environments. However, diagnostic injection tests are becoming quite common, as they provide key fracturing data such as estimates of closure stress, fluid efficiency, tortuosity, perforation friction, net pressure, and fracture complexity. Diagnostic injections consist of pumping small volumes of frac water (typically 2% KCl) prior to the main propped treatment and can easily be performed with little additional cost.

About 10 years ago Pinnacle's Mike Mayerhofer(7) introduced a method to estimate reservoir permeability and reservoir pressure using pressure decline data from diagnostic injection tests. Mike's work was modified by Valko et al.(8) and Halliburton's David Craig(9) and is commonly known as the "*Modified Mayerhofer Method*" - which separated the calculations of reservoir permeability and reservoir pressure (simplifying the analysis). The strength of these techniques is the ability to determine reservoir permeability and reservoir pressure from fracture pressure decline data before the fracture closes, which is essential in low permeability reservoirs where the application of "after closure" analysis methods is not practical. In recent years, operators and service companies have started to apply this technology to gain valuable information to improve fracture treatment designs and aid in infill drilling programs. This technology is especially useful in multi-zone completions to identify variations in reservoir permeability – modifying treatment designs accordingly, to determine which zones are fracturing targets – eliminating uneconomic zones, and to gather reservoir pressure data to optimize well spacing & placement.

The basis of the *Mayerhofer* and *Modified Mayerhofer* methods of estimating reservoir permeability is rooted in pressure transient analysis, integrating pressure transient solutions for an infinite conductivity vertical fracture with a varying filter cake skin effect to describe the filtration phenomena of leakoff during a diagnostic injection test. The Mayerhofer approach couples unsteady-state linear flow from a fracture with a varying skin effect at the fracture face and superposes the leakoff history on the pressure decline. This guarantees a correct rate-convolution to account for pressure dependent leakoff in the subsequent permeability analysis.

The Modified Mayerhofer Method includes a pseudo linear flow analysis to estimate reservoir pressure that is independent of the permeability analysis(10,11). The Mayerhofer permeability and Modified Mayerhofer reservoir pressure analyses have recently been added to FracproPT's suite of mini-frac analysis capabilities, making it even easier to use this powerful technology to improve your fracturing treatments.

How the Analysis Works

The first step in the analysis is to determine fracture closure pressure, typically using a combination of G-function and Log-Log analyses. **Figure 1** illustrates a typical G-function closure analysis.

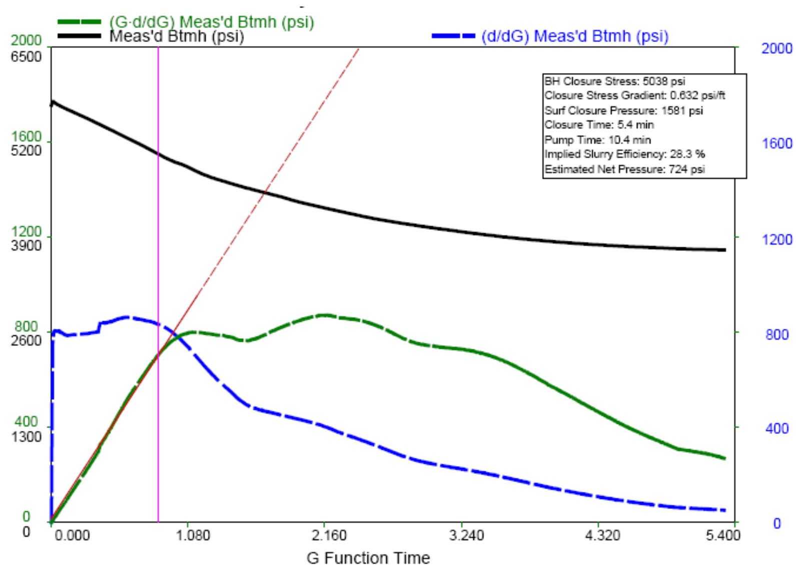


Figure 1 - G-function analysis for fracture closure

After closure is determined, the next step in the analysis is to determine when, after fracture closure, pseudo linear flow occurs. This is key to ensuring an accurate estimate of reservoir pressure. **Figure 2** illustrates how pseudo linear flow is determined by identifying the region of half-slope behavior using a specialized log-log plot.

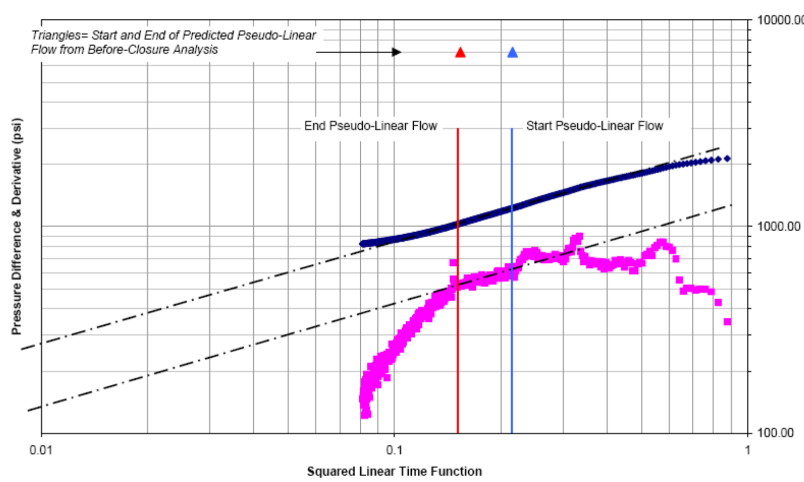


Figure 2 - Determination of after-closure pseudo-linear flow

Once the proper pseudo-linear flow (PLF) time region is identified, reservoir pressure can be estimated by extrapolating the pressure trend during PLF using an analysis technique similar to a Horner plot. **Figure 3** illustrates how reservoir pressure is estimated using pseudo-linear flow analysis.

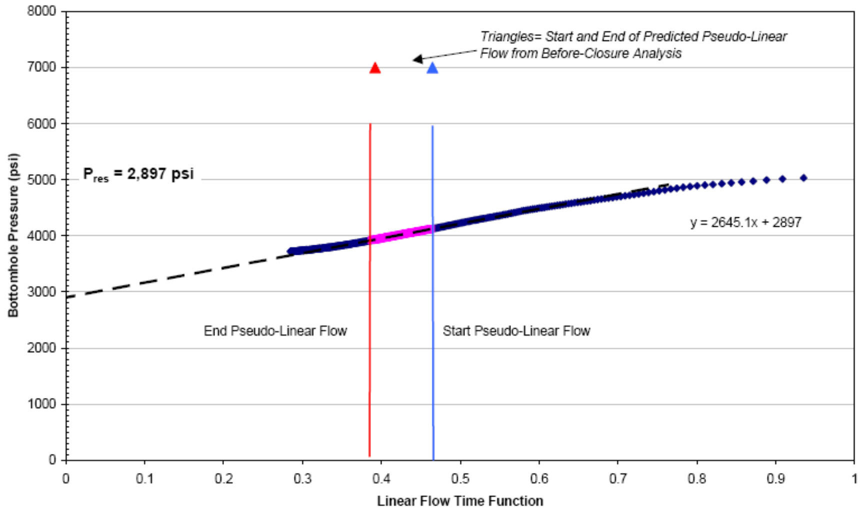


Figure 3 - Pseudo-linear analysis for reservoir pressure

Using the reservoir pressure to constrain the analysis, permeability can be determined by history matching the pressure decline data, before fracture closure, using the Mayerhofer solutions. **Figure 4** illustrates a typical permeability analysis using the Mayerhofer Method.

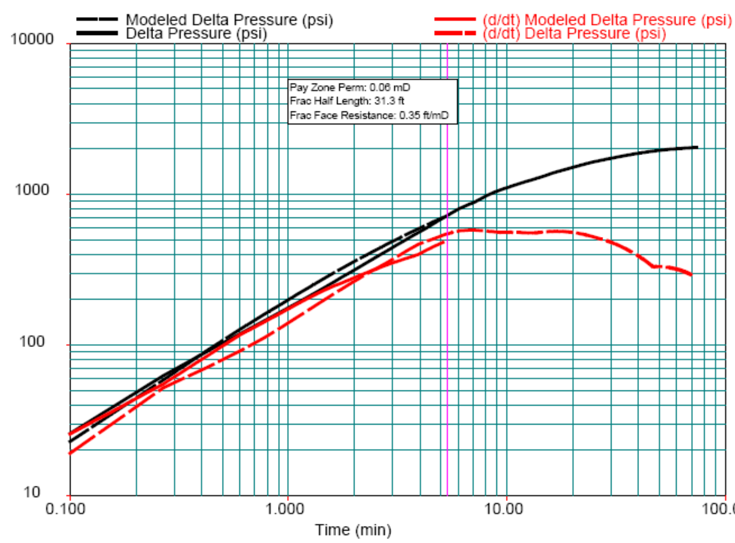


Figure 4 - Permeability using the Mayerhofer Method

The final step in the process is to cross-check the before-closure reservoir permeability estimate by calculating the expected beginning and end time for after-closure pseudo-linear flow and comparing this to the actual pressure decline behavior to ensure consistency in the analysis. This comparison is illustrated in **Figure 4** and shows that the actual after–closure PLF times are consistent with the ones calculated using the estimated before-closure reservoir permeability.

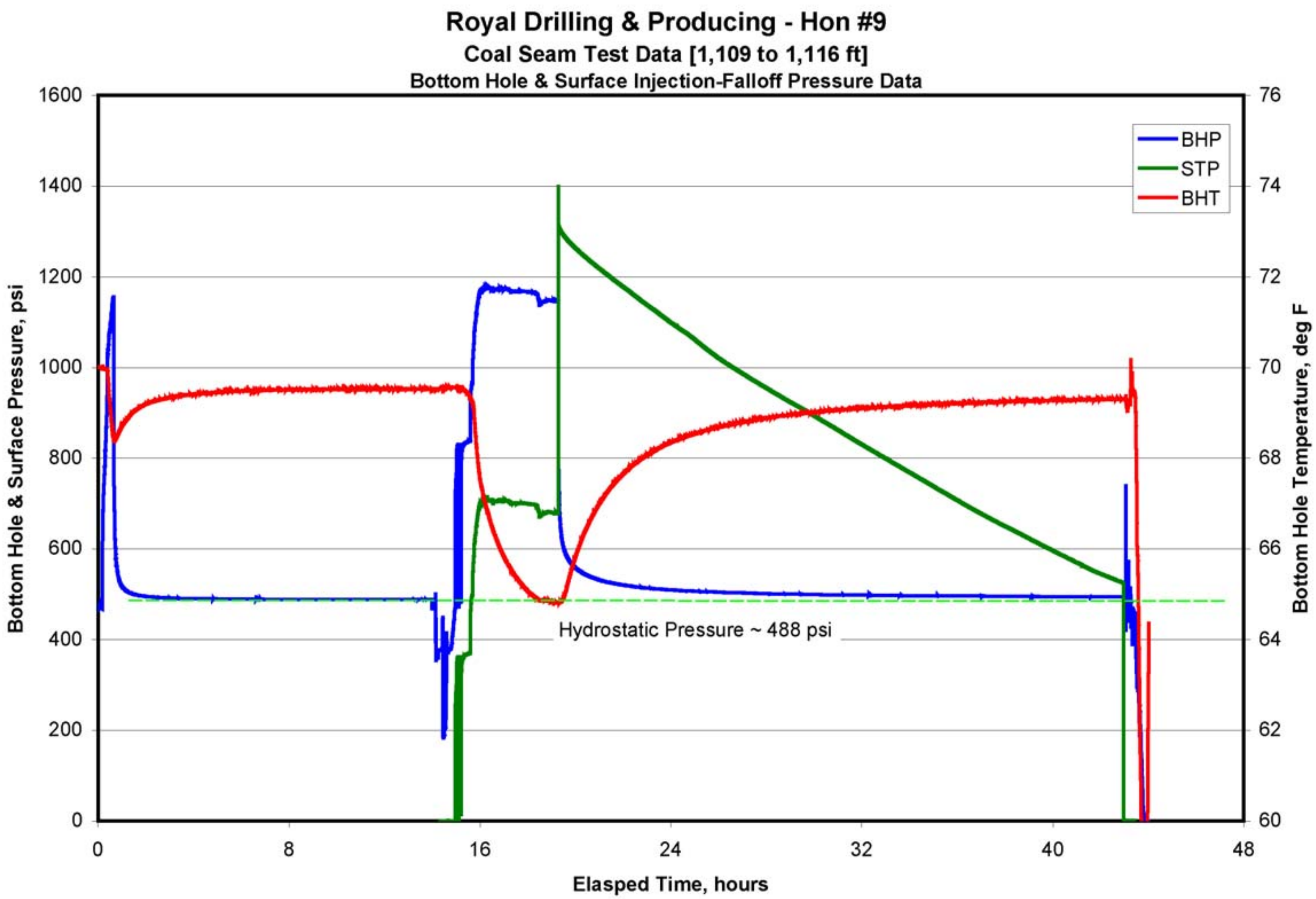
These simple, but powerful, pressure decline analysis tools can provide essential data to optimize fracture treatments and field development, with little additional cost, while also providing more *pieces-to-the-puzzle* of understanding fracture growth.

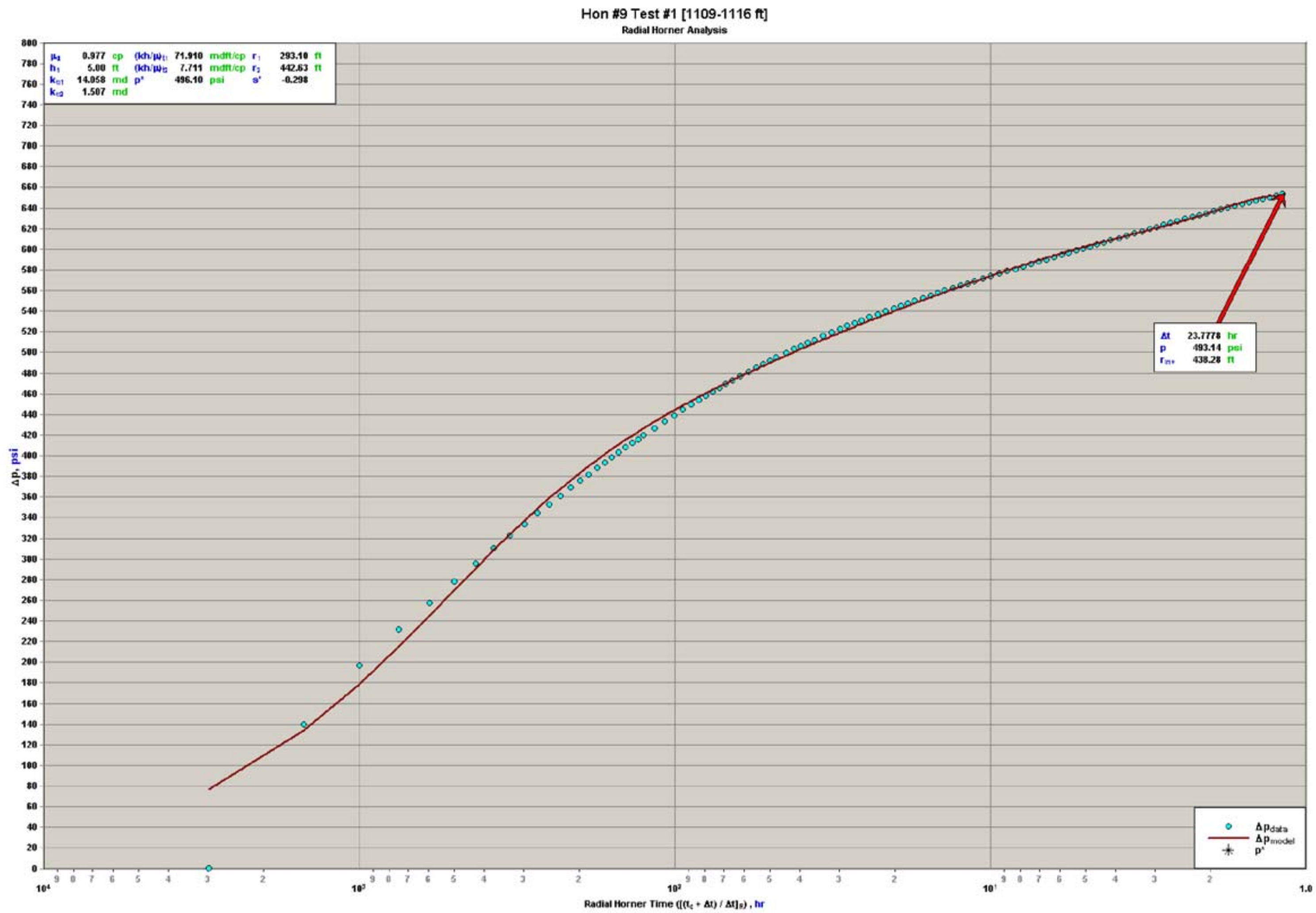
References:

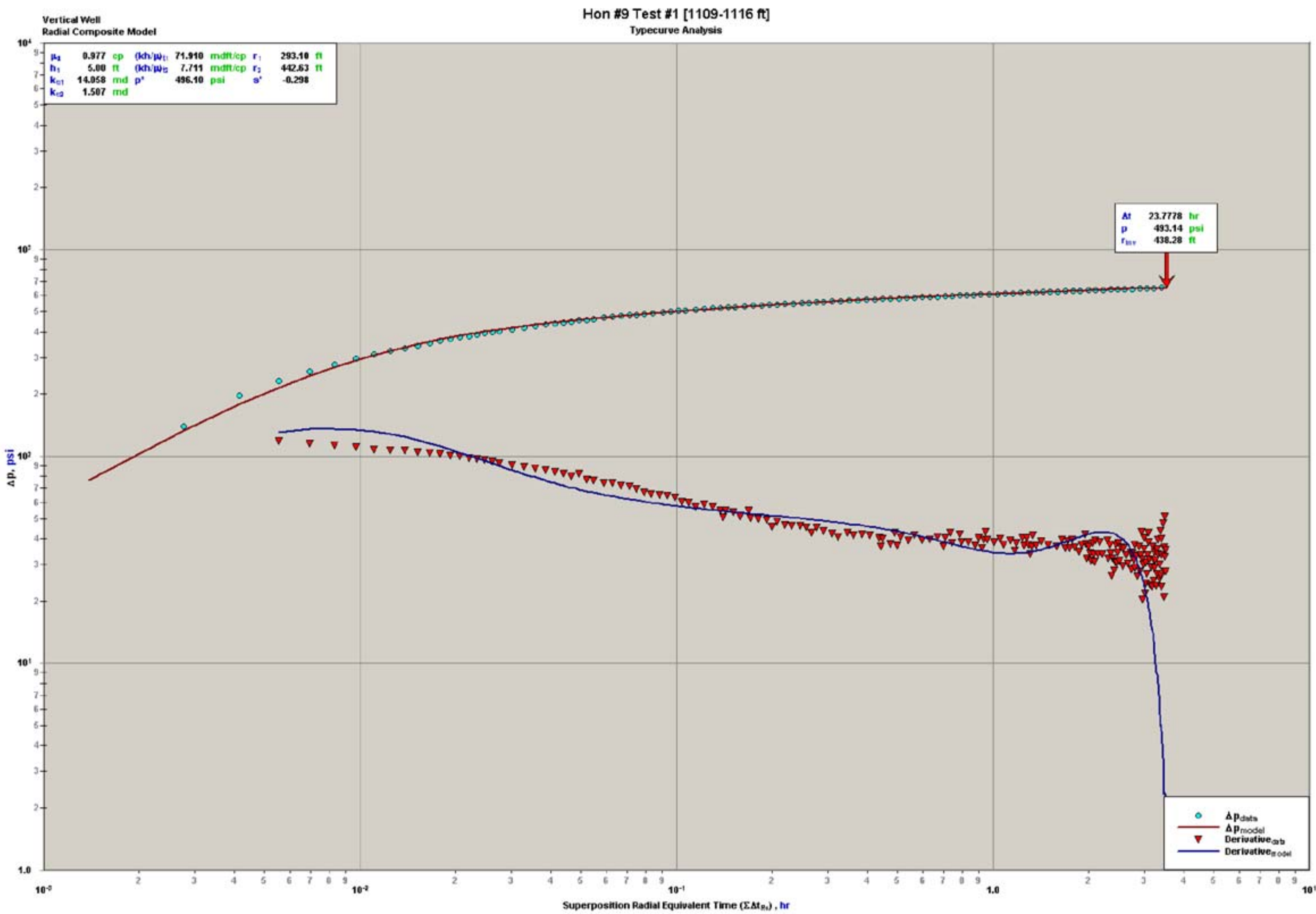
1. Mayerhofer, M.J., Ehlig-Economides, C.A., and Economides, M.J.: "Pressure-Transient Analysis of Fracture Calibration Tests," JPT (March 1995) 229-34.
2. Valko, P.P., and Economides, M.J.: "Fluid Leakoff Delineation in High-Permeability Fracturing," SPE Production & Facilities (May 1999) 117-30.
3. Craig, D.P., and Brown, T.D.: "Estimating Pore Pressure and Permeability in Massively Stacked Lenticular Reservoirs Using Diagnostic Fracture-Injection Tests," SPE 56600 presented at 1999 ATC in Houston.
4. Craig, D.P, Eberhard, M.J., Odegard, C.E., and Muthukumarappan, R., "Permeability, Pore Pressure, and Leakoff-Type Distributions in Rocky Mountain Basins," SPE 75717 presented at SPE Gas Technology Symposium, Calgary 2002
5. Craig, D.P, Eberhard, M.J., and Barree, R.D.: " Adapting High Permeability Leakoff Analysis to Low Permeability Sands for Estimating Reservoir Engineering Parameters": SPE 60291 presented at SPE Low Permeability Symposium in Denver, 2000.

Hon # 9 Injection-Falloff Testing Results

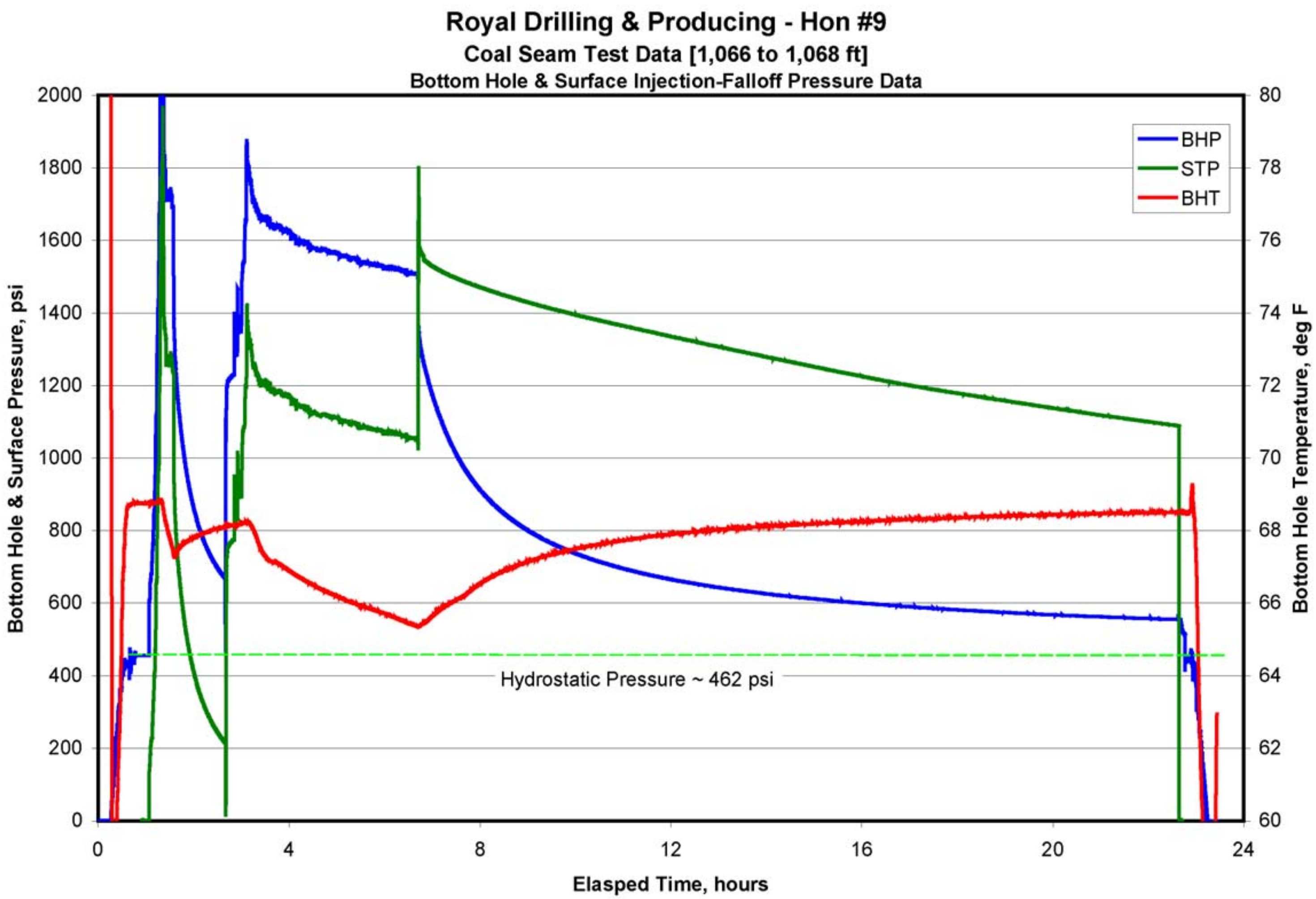
Well Name / Interval	Perforation Depth (ft)	Calculated Permeability (mD)	Calculated Avg Reservoir Pressure (psi)	Test Radius of Investigation (ft)	Skin Factor
Test 1	1109-16 (5’ net)	14.1	496 (0.45 psi/ft)	440	-0.3
Test 2	1066-68 (2’ net)	5.2	516 (0.48 psi/ft)	120	-3.4
Test 3	996-1000 (4’ net)	3.3	440 (0.44 psi/ft)	189	-4.9
Test 4	884-886 (4’ net)	21.7	681 (0.77 psi/ft)	497	-1.8
Test 5	805-810 (5’ net)	4.3	510 (0.63 psi/ft)	219	-4.9
Test 6	759-761 (2’ net)	34.4	328 (0.43 psi/ft)	650	NA

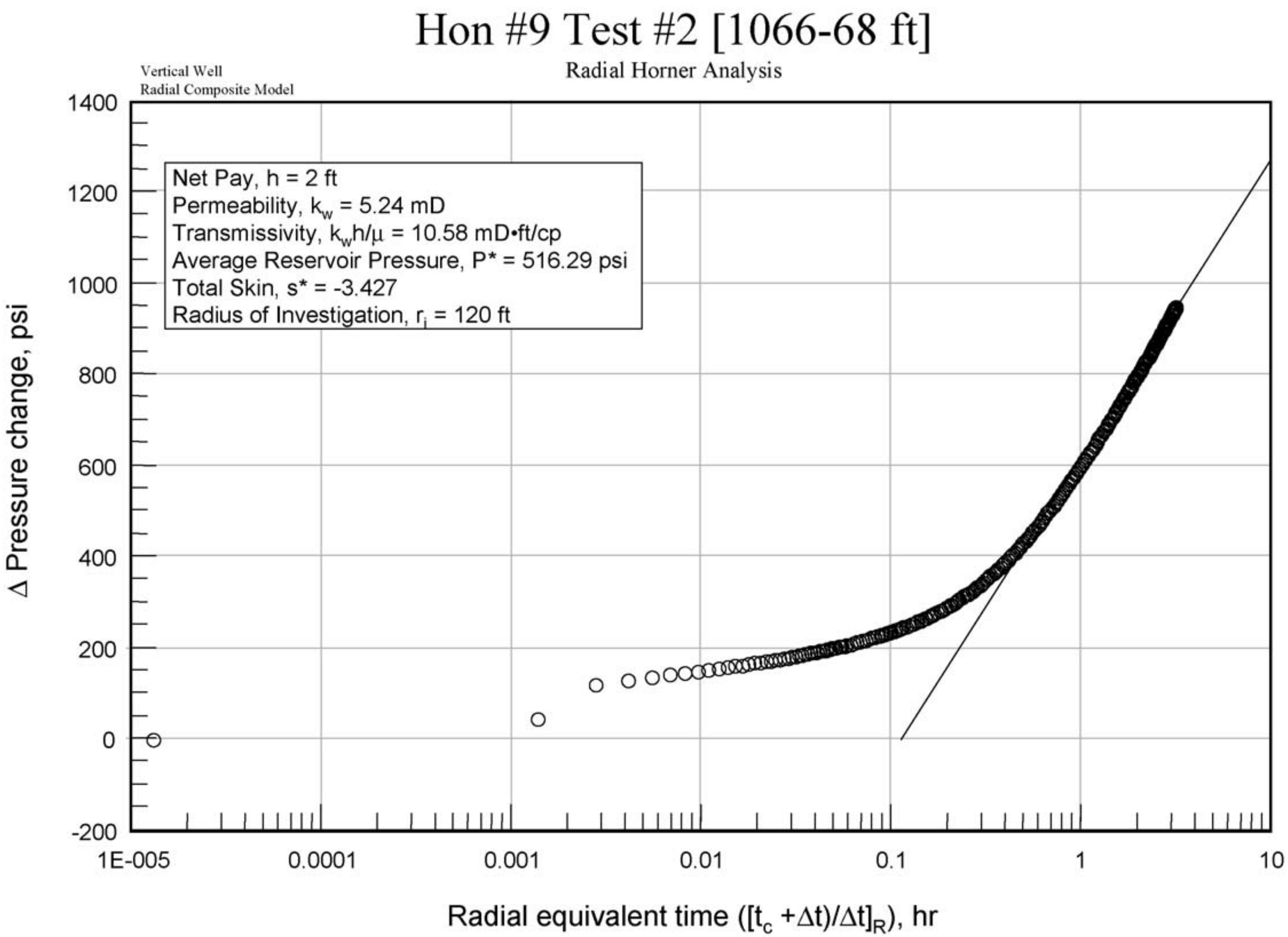

Royal Drilling & Producing - Hon #9
Coal Seam Test Data [1,109 to 1,116 ft]
Bottom Hole & Surface Injection-Falloff Pressure Data
BHP
STP
BHT
Hydrostatic Pressure ~ 488 psi
Bottom Hole & Surface Pressure, psi
Bottom Hole Temperature, deg F
Elasped Time, hours
0
8
16
24
32
40
48
0
200
400
600
800
1000
1200
1400
1600
60
62
64
66
68
70
72
74
76

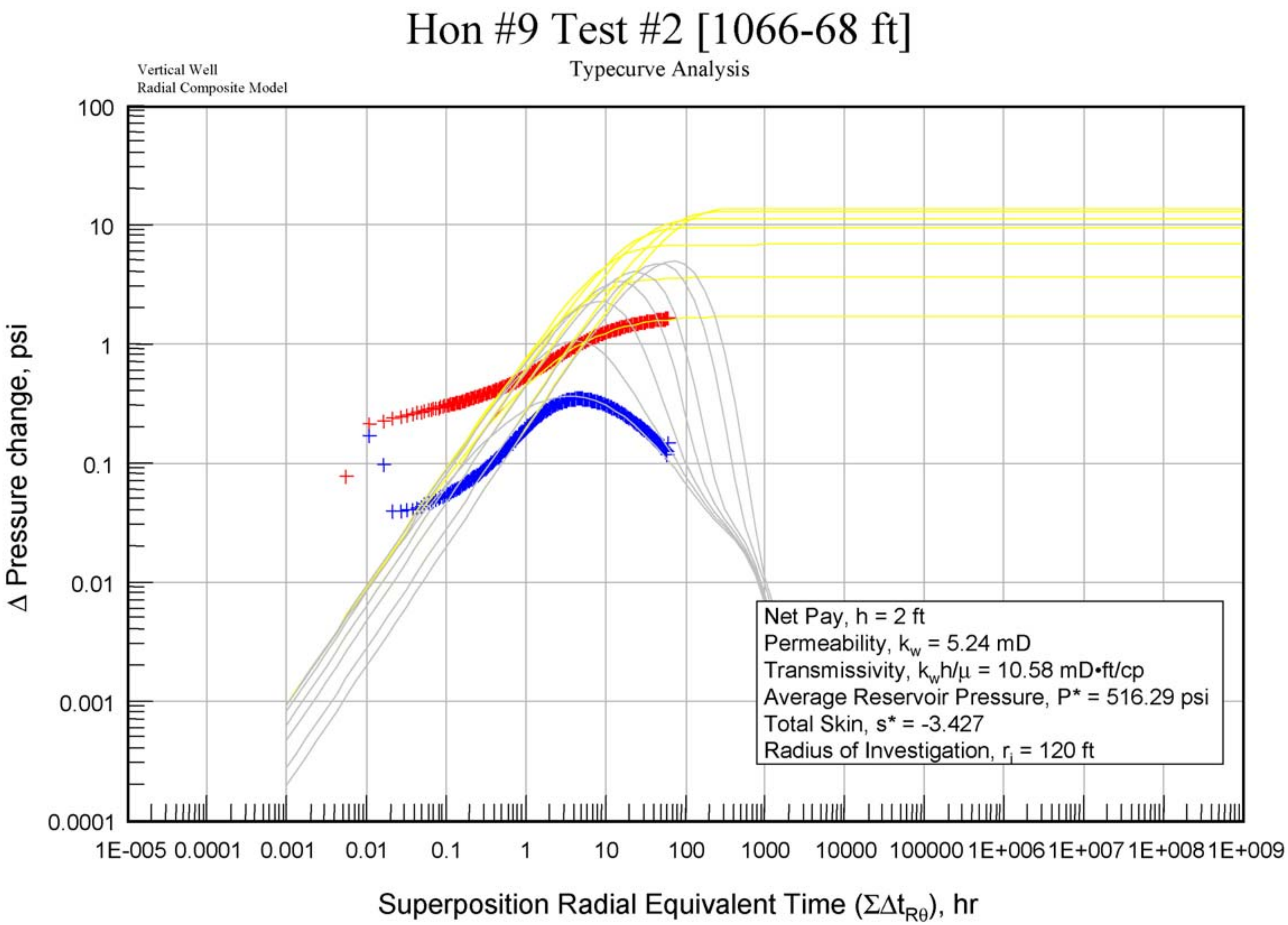

Hon #9 Test #1 [1109-1116 ft]
Radial Horner Analysis
μ1 0.977 cp (kh/μ)t1 71.910 mdft/cp r1 293.10 ft
h1 5.00 ft (kh/μ)t2 7.711 mdft/cp r2 442.63 ft
kc1 14.058 md p* 496.10 psi s* -0.298
kc2 1.507 md
Δt 23.7778 hr
p 493.14 psi
rinv 438.28 ft
Δpdata
Δpmodel
p*
Δp, psi
Radial Horner Time ([(tc + Δt) / Δt]R) , hr

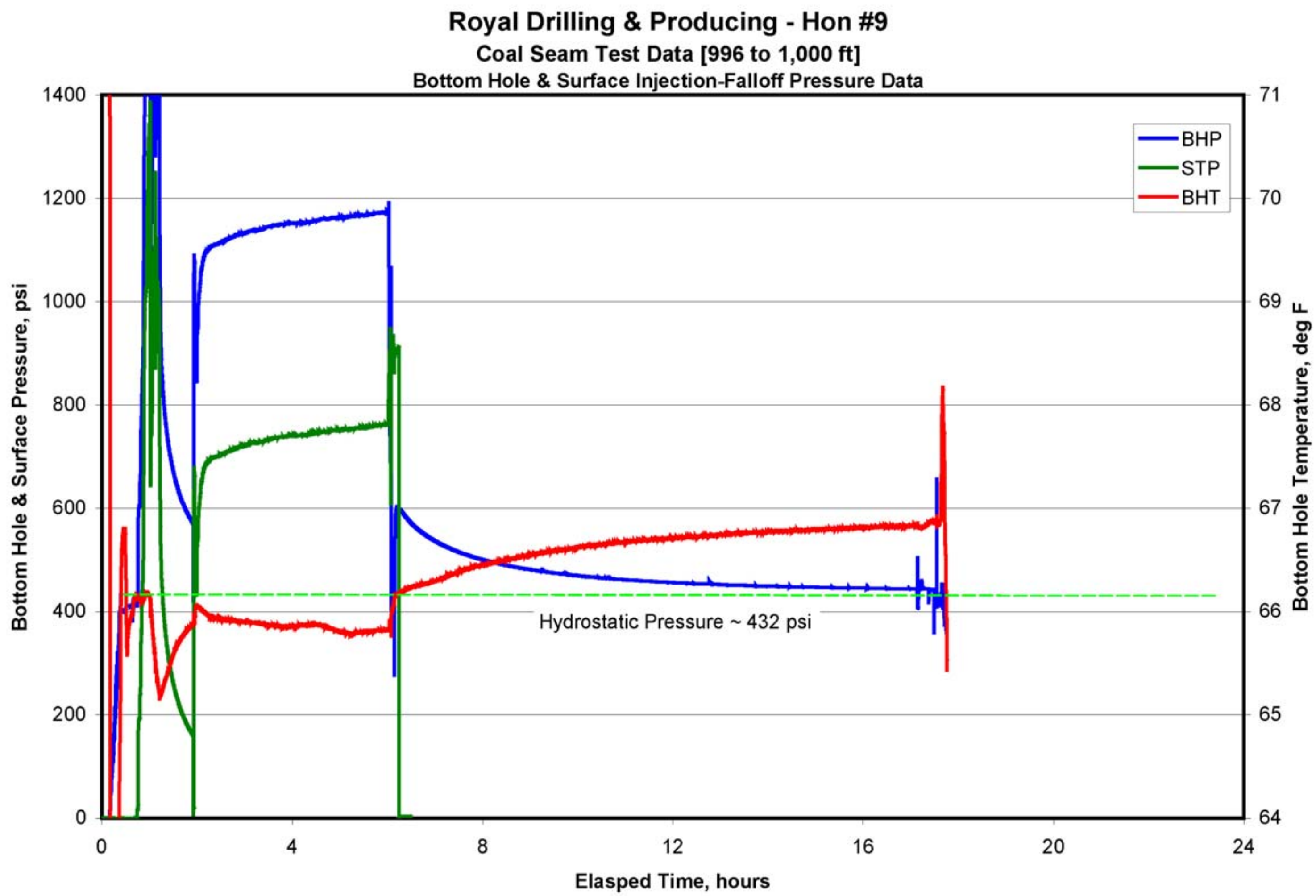


Hon #9 Test #1 [1109-1116 ft]
Typecurve Analysis
Vertical Well
Radial Composite Model
μ 0.977 cp
h 5.00 ft
k 14.058 md
k 1.507 md
(kh/μ) 71.910 mdft/cp
(kh/μ) 7.711 mdft/cp
p* 496.10 psi
r 293.10 ft
r 442.63 ft
s' -0.298
Δt 23.7778 hr
p 493.14 psi
r 438.28 ft
Δp, psi
Superposition Radial Equivalent Time (ΣΔt), hr
Δp data
Δp model
Derivative data
Derivative model

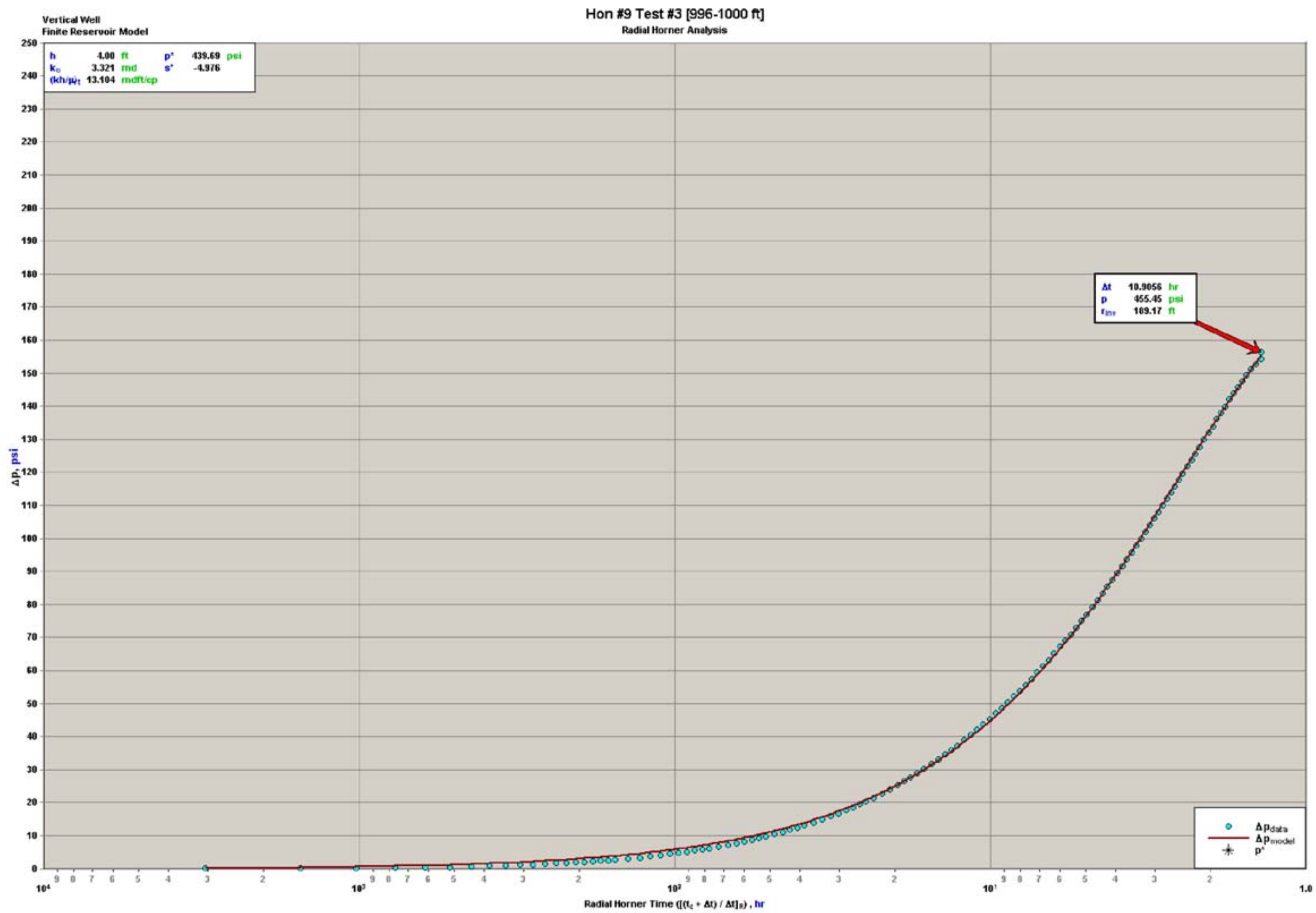

Royal Drilling & Producing - Hon #9
Coal Seam Test Data [1,066 to 1,068 ft]
Bottom Hole & Surface Injection-Falloff Pressure Data
BHP
STP
BHT
Hydrostatic Pressure ~ 462 psi
Bottom Hole & Surface Pressure, psi
Bottom Hole Temperature, deg F
Elasped Time, hours
0
200
400
600
800
1000
1200
1400
1600
1800
2000
60
62
64
66
68
70
72
74
76
78
80
0
4
8
12
16
20
24


Hon #9 Test #2 [1066-68 ft]
Radial Horner Analysis
Vertical Well
Radial Composite Model
Net Pay, h = 2 ft
Permeability, k_w = 5.24 mD
Transmissivity, $k_w h/\mu$ = 10.58 mD•ft/cp
Average Reservoir Pressure, P* = 516.29 psi
Total Skin, s* = -3.427
Radius of Investigation, r_i = 120 ft
Δ Pressure change, psi
1400
1200
1000
800
600
400
200
0
-200
1E-005
0.0001
0.001
0.01
0.1
1
10
Radial equivalent time ($[t_c + \Delta t)/\Delta t]_R$), hr

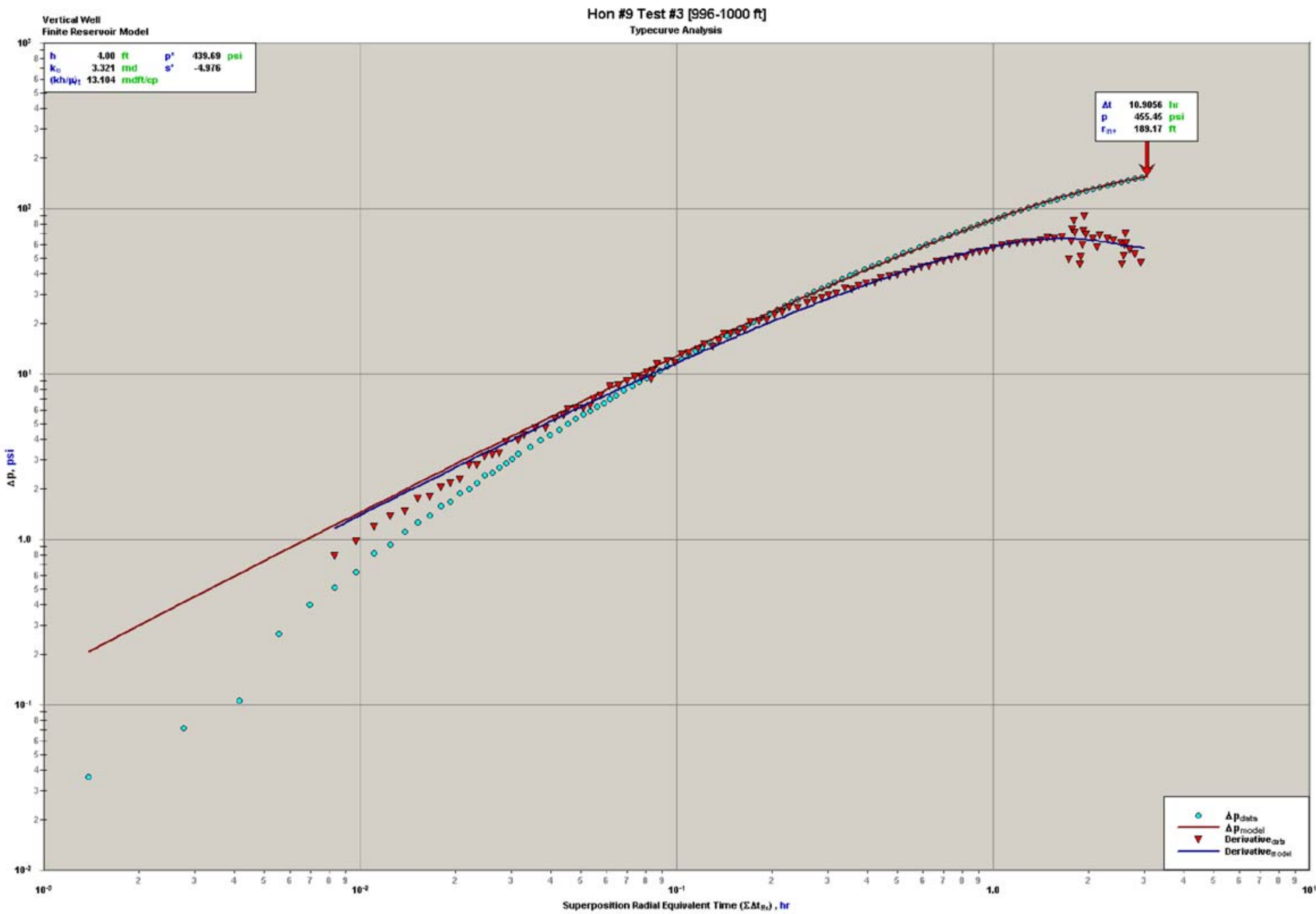

Hon #9 Test #2 [1066-68 ft]
Typecurve Analysis
Vertical Well
Radial Composite Model
Δ Pressure change, psi
100
10
1
0.1
0.01
0.001
0.0001
1E-005 0.0001 0.001 0.01 0.1 1 10 100 1000 10000 100000 1E+006 1E+007 1E+008 1E+009
Superposition Radial Equivalent Time (ΣΔt_Rθ), hr
Net Pay, h = 2 ft
Permeability, k_w = 5.24 mD
Transmissivity, k_wh/μ = 10.58 mD•ft/cp
Average Reservoir Pressure, P* = 516.29 psi
Total Skin, s* = -3.427
Radius of Investigation, r_i = 120 ft

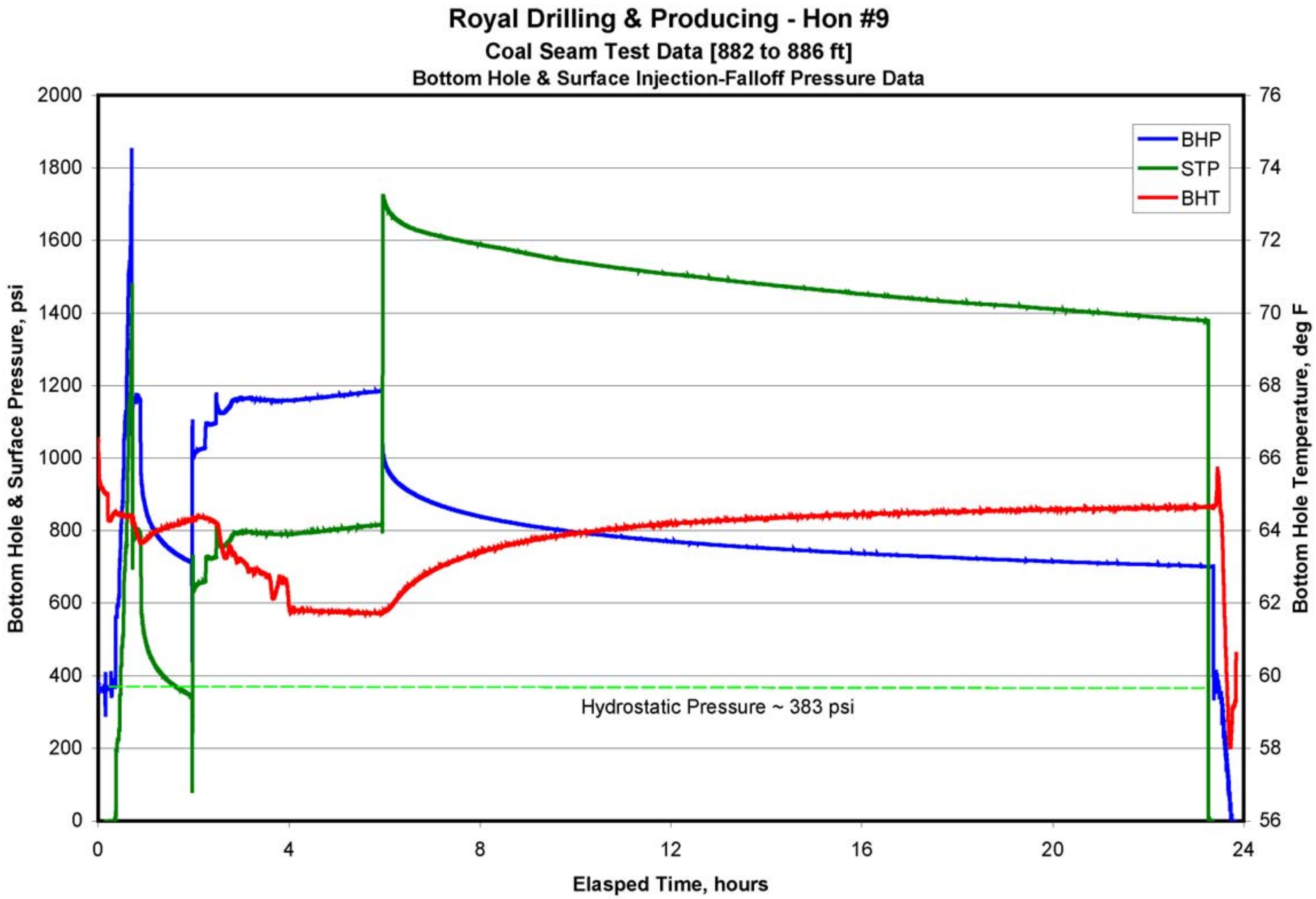


Royal Drilling & Producing - Hon #9
Coal Seam Test Data [996 to 1,000 ft]
Bottom Hole & Surface Injection-Falloff Pressure Data
Bottom Hole & Surface Pressure, psi
Bottom Hole Temperature, deg F
Elasped Time, hours
BHP
STP
BHT
Hydrostatic Pressure ~ 432 psi
0
200
400
600
800
1000
1200
1400
64
65
66
67
68
69
70
71
0
4
8
12
16
20
24

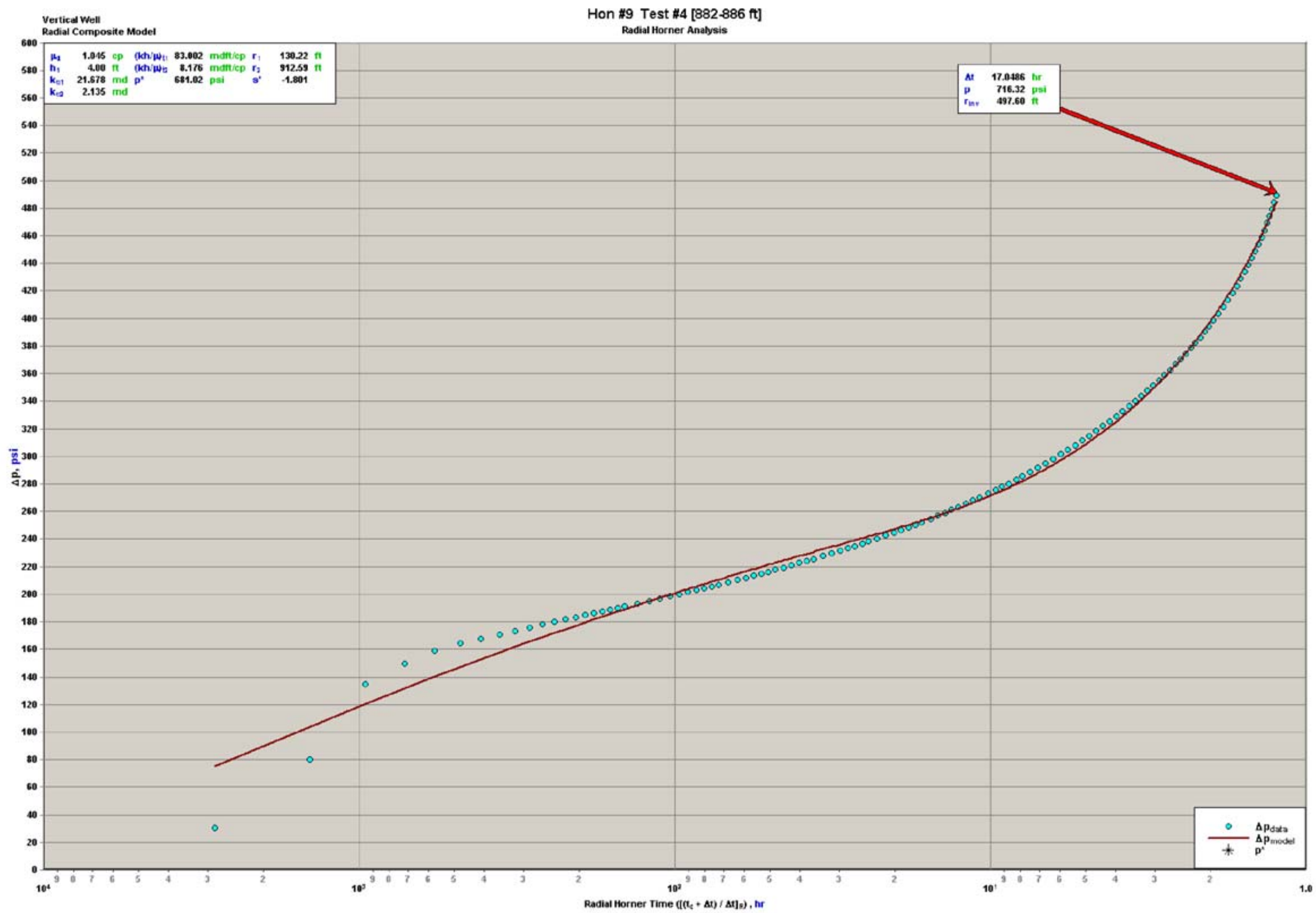


Hon #9 Test #3 [996-1000 ft]
Radial Horner Analysis
Vertical Well
Finite Reservoir Model
h 4.00 ft
k_0 3.321 md
$(kh/\mu)_t$ 13.104 mdft/cp
p* 439.69 psi
s' -4.976
Δt 10.9056 hr
p 455.45 psi
r_{inv} 189.17 ft
Δp_{data}
Δp_{model}
p*
Δp, psi
Radial Horner Time ([(t_c + Δt) / Δt]$_s$) , hr

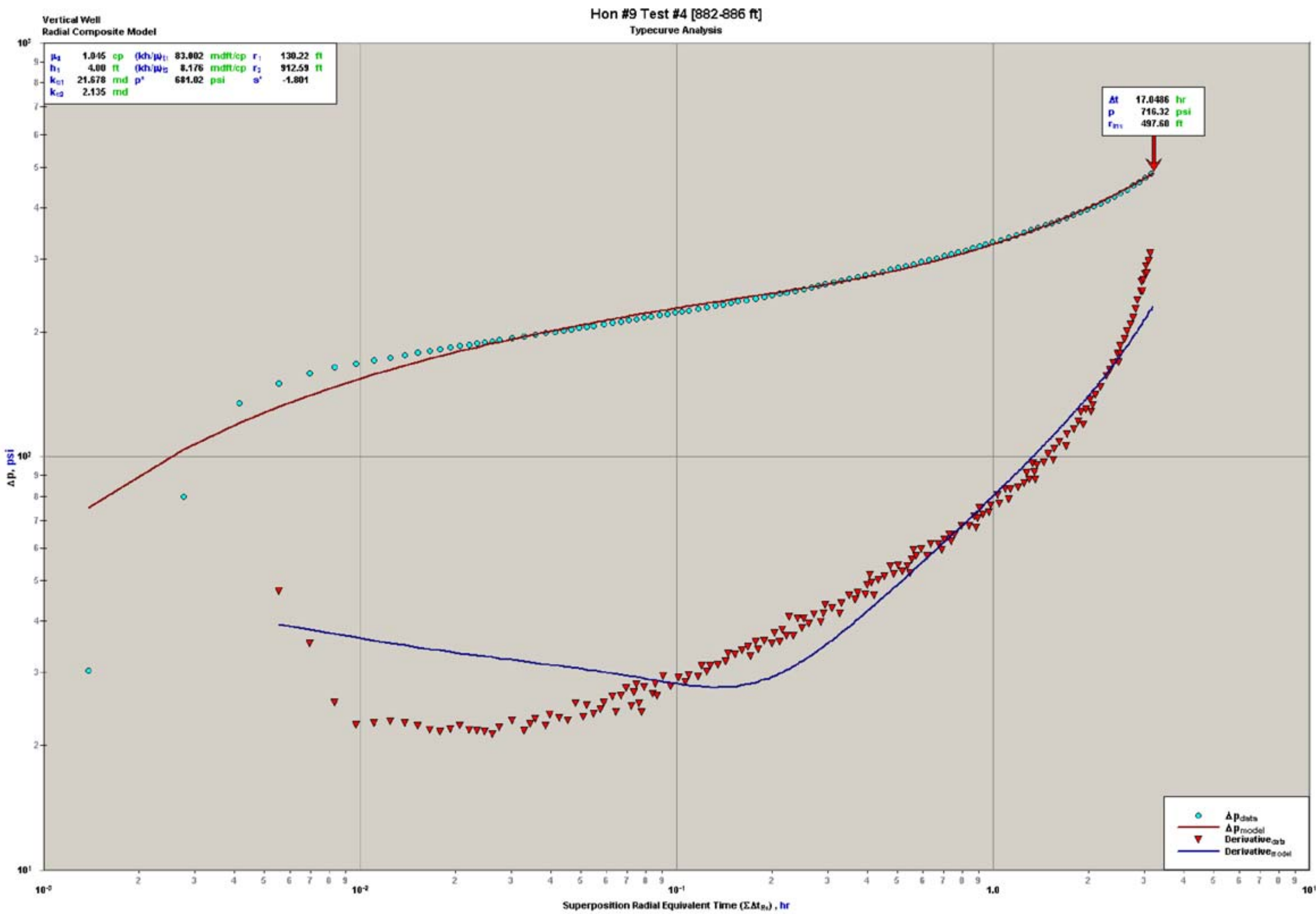

Hon #9 Test #3 [996-1000 ft]
Typecurve Analysis
Vertical Well
Finite Reservoir Model
h 4.00 ft
k 3.321 md
(kh/μ)t 13.104 mdft/cp
p* 439.69 psi
s* -4.976
Δt 10.9056 hr
p 455.45 psi
r 189.17 ft
Δp, psi
Superposition Radial Equivalent Time (ΣΔt), hr
Δp data
Δp model
Derivative data
Derivative model

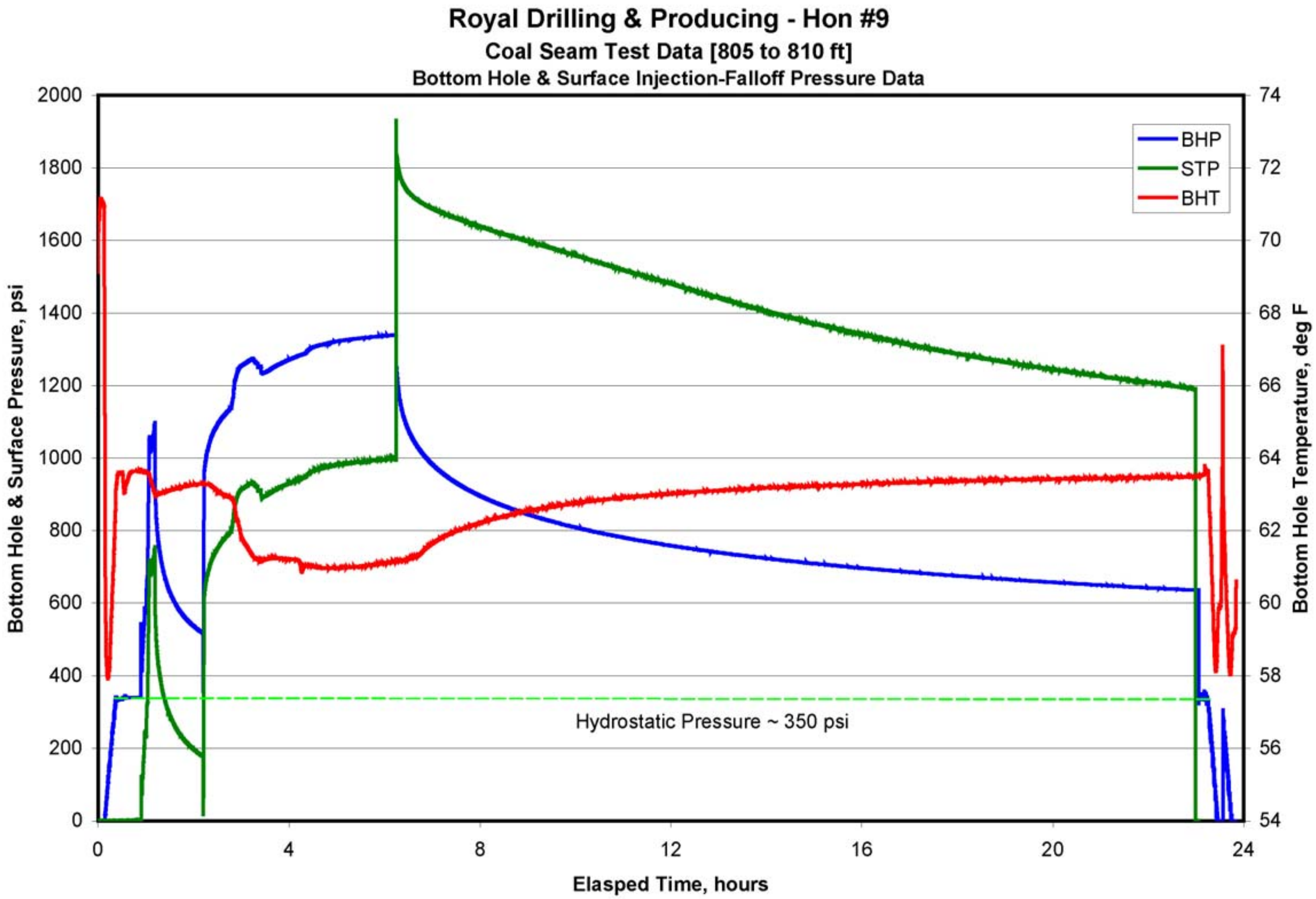


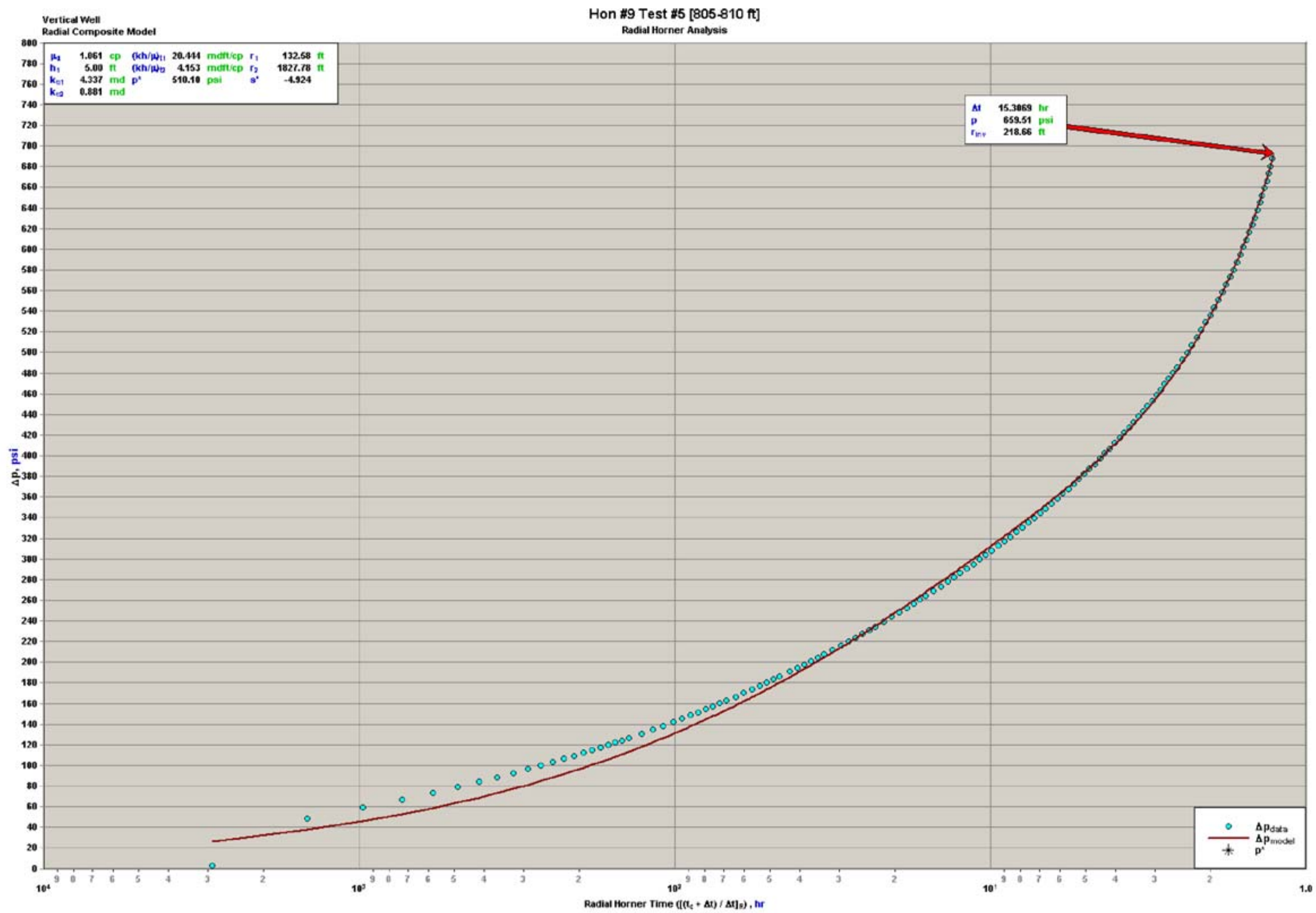
Royal Drilling & Producing - Hon #9
Coal Seam Test Data [882 to 886 ft]
Bottom Hole & Surface Injection-Falloff Pressure Data
Bottom Hole & Surface Pressure, psi
Bottom Hole Temperature, deg F
Elasped Time, hours
BHP
STP
BHT
Hydrostatic Pressure ~ 383 psi
0
200
400
600
800
1000
1200
1400
1600
1800
2000
56
58
60
62
64
66
68
70
72
74
76
0
4
8
12
16
20
24



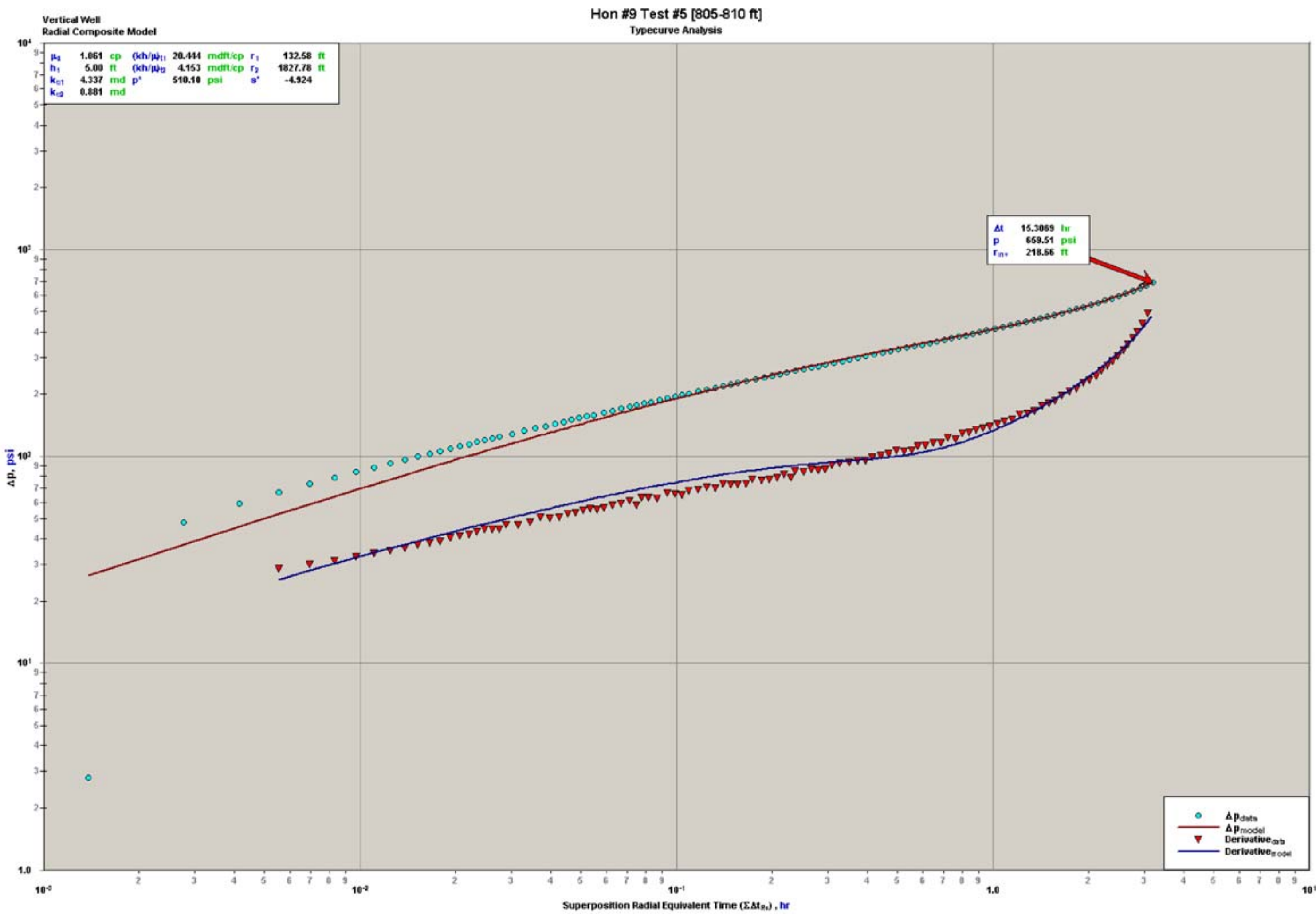
Hon #9 Test #4 [882-886 ft]
Radial Horner Analysis
Vertical Well
Radial Composite Model
μ 1.045 cp (kh/μ)t1 83.002 mdft/cp r1 130.22 ft
h1 4.00 ft (kh/μ)t2 8.176 mdft/cp r2 912.59 ft
kt1 21.678 md p* 681.02 psi s' -1.801
kt2 2.135 md
Δt 17.0486 hr
p 716.32 psi
rinv 497.60 ft
Δp, psi
Radial Horner Time ([(tc + Δt) / Δt]s) , hr
Δpdata
Δpmodel
p*

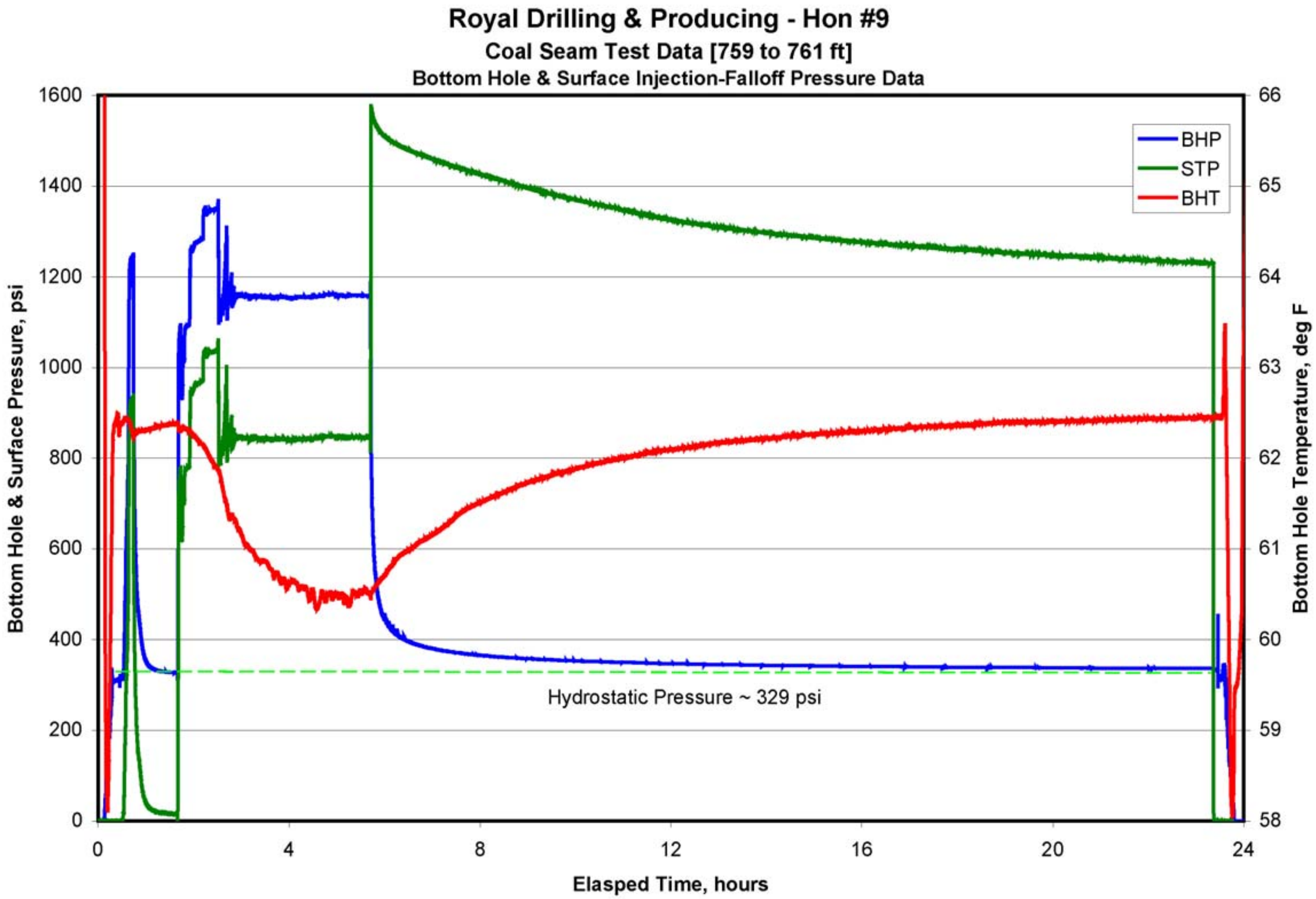

Hon #9 Test #4 [882-886 ft]
Typecurve Analysis
Vertical Well
Radial Composite Model
μ 1.045 cp (kh/μ)t1 83.002 mdft/cp r1 130.22 ft
h1 4.00 ft (kh/μ)t2 8.176 mdft/cp r2 912.59 ft
kt1 21.678 md p* 681.02 psi s' -1.801
kt2 2.135 md
Δt 17.0486 hr
p 716.32 psi
rinv 497.60 ft
Δp data
Δp model
Derivative data
Derivative model
Δp, psi
Superposition Radial Equivalent Time (ΣΔtRE) , hr

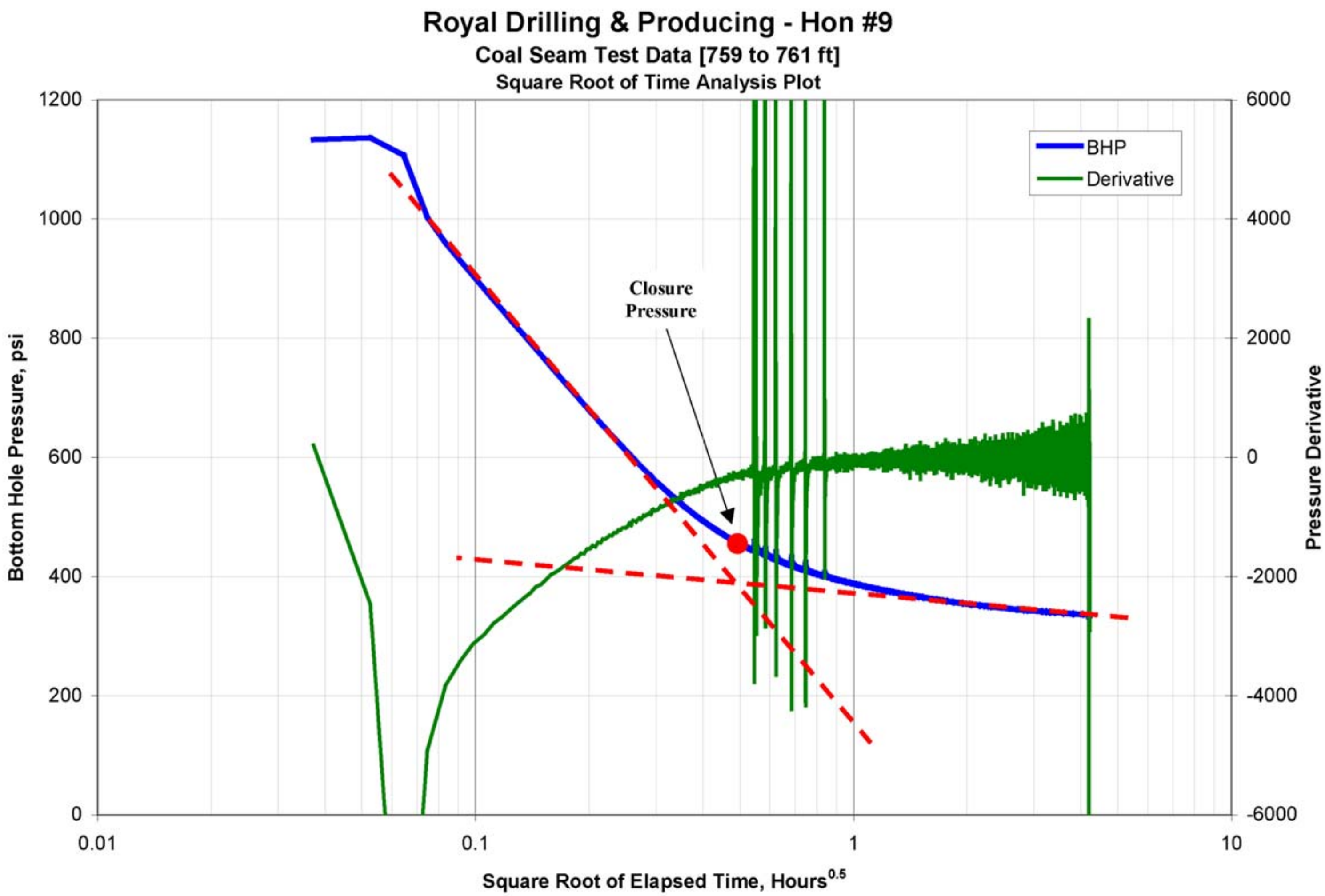

Royal Drilling & Producing - Hon #9
Coal Seam Test Data [805 to 810 ft]
Bottom Hole & Surface Injection-Falloff Pressure Data
Bottom Hole & Surface Pressure, psi
Bottom Hole Temperature, deg F
Elasped Time, hours
BHP
STP
BHT
Hydrostatic Pressure ~ 350 psi
2000
1800
1600
1400
1200
1000
800
600
400
200
0
74
72
70
68
66
64
62
60
58
56
54
0
4
8
12
16
20
24



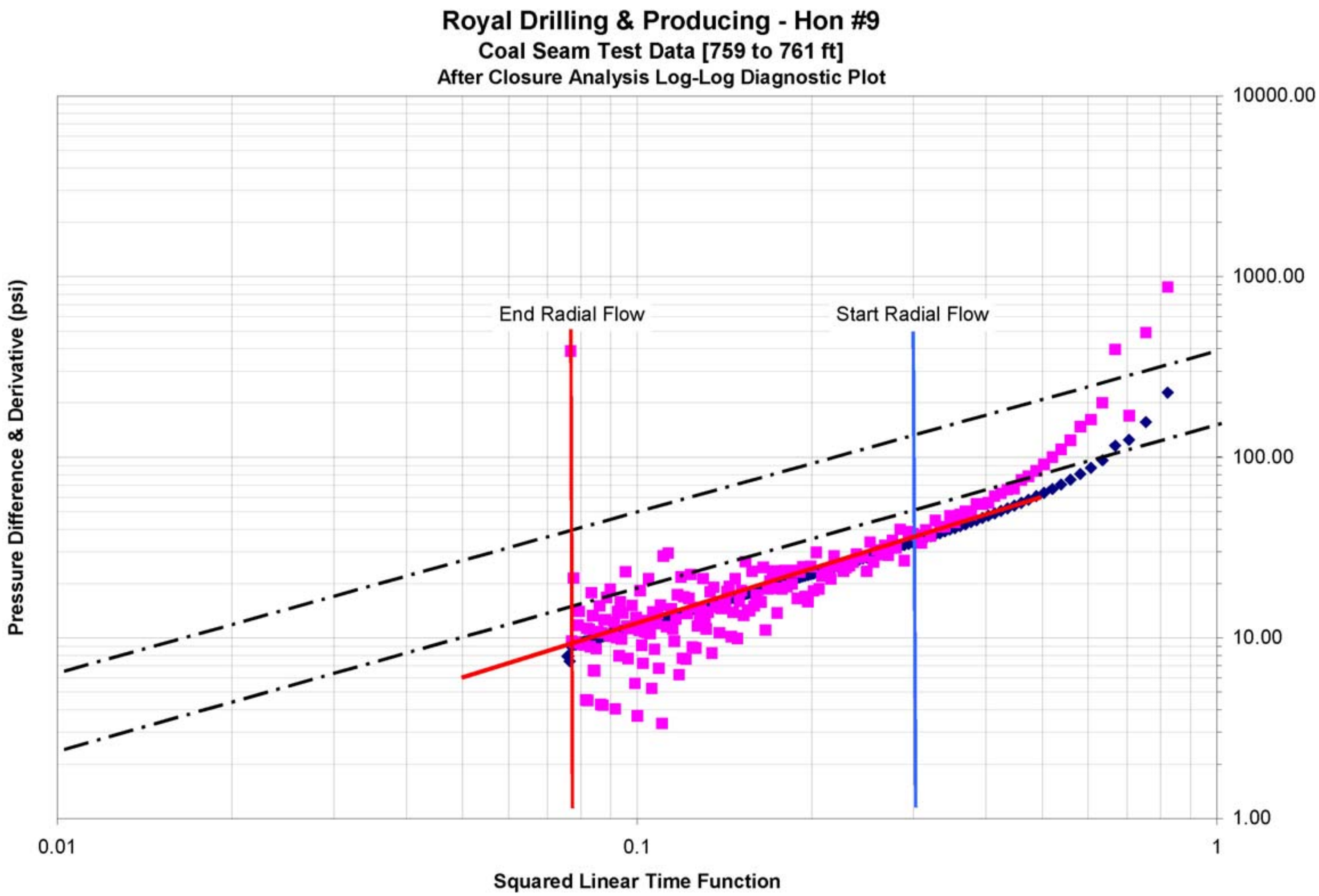
Hon #9 Test #5 [805-810 ft]
Radial Horner Analysis
Vertical Well
Radial Composite Model
μ_1 1.061 cp
h_1 5.00 ft
k_{r1} 4.337 md
k_{r2} 0.881 md
$(kh/\mu)_{t1}$ 20.444 mdft/cp
$(kh/\mu)_{t2}$ 4.153 mdft/cp
p* 510.10 psi
r_1 132.68 ft
r_2 1827.78 ft
s' -4.924
Δt 15.3069 hr
p 659.51 psi
r_{inv} 218.66 ft
Δp, psi
Radial Horner Time ([(tc + Δt) / Δt]s) , hr
Δp_{data}
Δp_{model}
p*

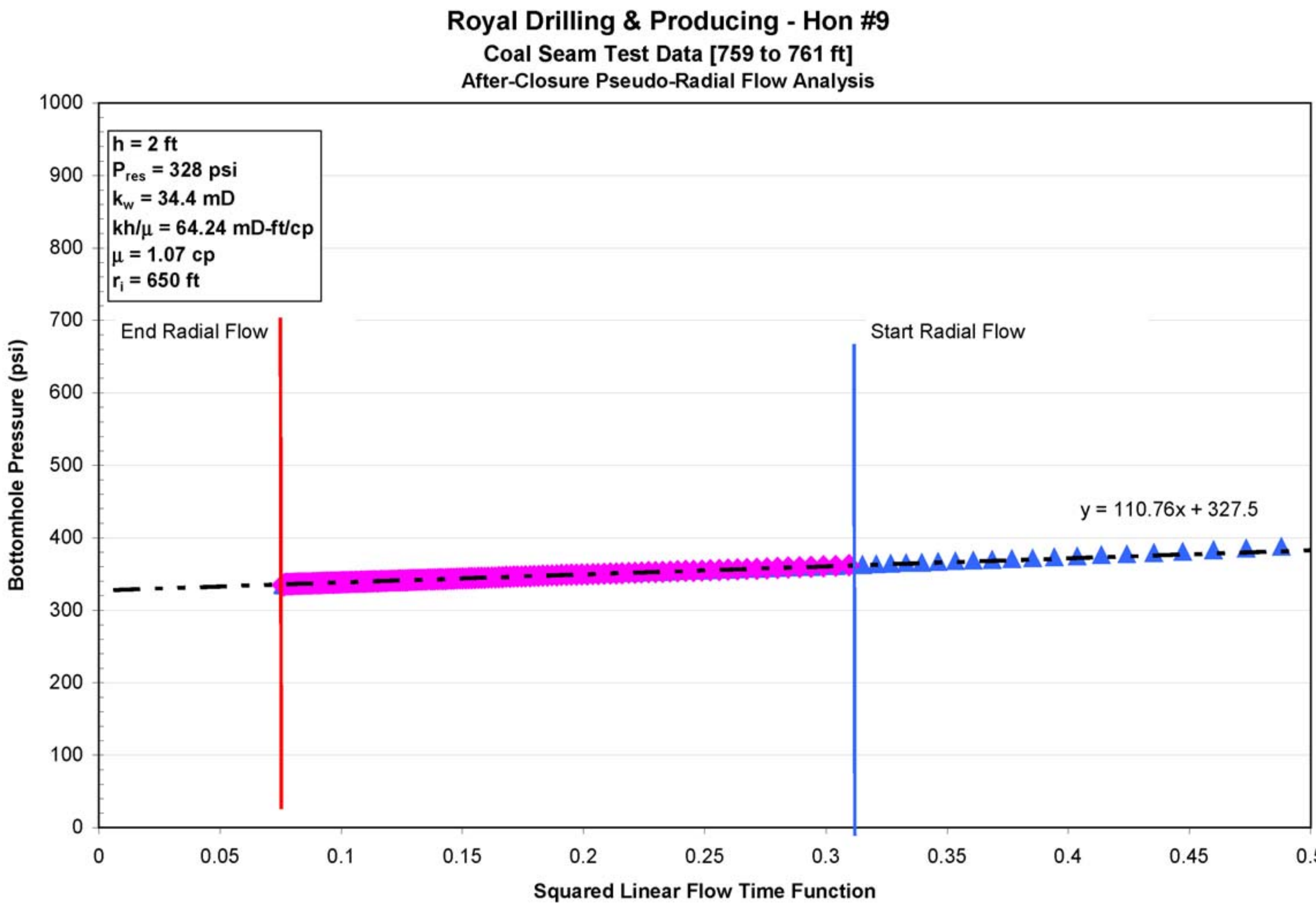

Hon #9 Test #5 [805-810 ft]
Typecurve Analysis
Vertical Well
Radial Composite Model
μ1 1.061 cp (kh/μ)t1 20.444 mdft/cp r1 132.68 ft
h1 5.00 ft (kh/μ)t2 4.153 mdft/cp r2 1827.78 ft
kt1 4.337 md p* 510.10 psi s' -4.924
kt2 0.881 md
Δt 15.3069 hr
p 669.51 psi
rinv 218.66 ft
Δp, psi
Superposition Radial Equivalent Time (ΣΔtRe) , hr
Δpdata
Δpmodel
Derivativedata
Derivativemodel


Royal Drilling & Producing - Hon #9
Coal Seam Test Data [759 to 761 ft]
Bottom Hole & Surface Injection-Falloff Pressure Data
BHP
STP
BHT
Hydrostatic Pressure ~ 329 psi
Bottom Hole & Surface Pressure, psi
Bottom Hole Temperature, deg F
Elasped Time, hours
1600
1400
1200
1000
800
600
400
200
0
66
65
64
63
62
61
60
59
58
0
4
8
12
16
20
24



Royal Drilling & Producing - Hon #9
Coal Seam Test Data [759 to 761 ft]
Square Root of Time Analysis Plot
Bottom Hole Pressure, psi
Pressure Derivative
Square Root of Elapsed Time, Hours^0.5
BHP
Derivative
Closure Pressure
1200
1000
800
600
400
200
0
6000
4000
2000
0
-2000
-4000
-6000
0.01
0.1
1
10


Royal Drilling & Producing - Hon #9
Coal Seam Test Data [759 to 761 ft]
After Closure Analysis Log-Log Diagnostic Plot
End Radial Flow
Start Radial Flow
10000.00
1000.00
100.00
10.00
1.00
0.01
0.1
1
Pressure Difference & Derivative (psi)
Squared Linear Time Function


Royal Drilling & Producing - Hon #9
Coal Seam Test Data [759 to 761 ft]
After-Closure Pseudo-Radial Flow Analysis
h = 2 ft
P_res = 328 psi
k_w = 34.4 mD
kh/μ = 64.24 mD-ft/cp
μ = 1.07 cp
r_i = 650 ft
End Radial Flow
Start Radial Flow
y = 110.76x + 327.5
Bottomhole Pressure (psi)
Squared Linear Flow Time Function
1000
900
800
700
600
500
400
300
200
100
0
0
0.05
0.1
0.15
0.2
0.25
0.3
0.35
0.4
0.45
0.5

Pinnacle Technologies PermPT Data Sheet

Test Date: May 9, 2004

Well Name:	Hon #9				
Operator:	Royal Drilling & Producing				
Perforations:	759 to 761 ft		Total Perf's:	2	*ft*
Fluid Type:	Water		Fluid Gradient:	0.433	*psi/ft*
Hydrostatic:	329	*psi*	Fracture Gradient:	1.57	*psi/ft*
Maximum STP:	[Frac Gradient – Fluid Gradient] x Mid Perf Depth:			864	*psi*

Test Data

Time of Day (24 hr) (hh:mm)	Δt (min)	Tank Fluid Level (inches)	Injection Rate (gpm)	Injection Pressure (psi)	Comments
09:30	0	38 7/8		750	Start injection
09:45	15	38 5/8 3.70 gals	0.25	796	Pressure increased
10:00	30	38 1/4 9.20 gals	0.93	984	Pressure increased
10:15	45	37 5/8 18.46 gals	0.62	1050	Pressure increased
10:30	60	36 9/16 34.20 gals	1.05	850	
11:00	90	34 1/8 70.30 gals	1.20	855	
11:30	120	31 9/16 107.33 gals	1.23	856	
12:00	150	29 --- 146.21 gals	1.30	857	
12:30	180	26 3/8 185.09 gals	1.30	859	
13:00	210	23 5/8 225.82 gals	1.36	859	
13:30	240	20 9/16 271.18 gals	1.51	860	Conclude injection
Test Totals		271 gals			
Average			1.13 gpm	692 psi	

Additional Test Information:

07:00 On site rigging up

08:25 Breakdown started, no breakdown noted. Pumped 5.55 gals @ 1.11 gpm, 900 psi

08:35 Shut in well ISIP = 750 psi

09:15 Began injection test, no break down noted

10:17 Pressure increased noted breakdown to 850

13:35 Downhole valve closed. Increased surface pressure to 1,600 psi.

BHP pressure gauges at 742 ft

Pinnacle on-site supervisor: Brian Laging

Pinnacle Technologies PermPT Data Sheet
Test Date: May 4, 2004

Well Name:	Hon #9					
Operator:	Royal Drilling & Producing					
Perforations:	1109-11 ft & 1113-16 ft			Total Perf's:	5	*ft*
Fluid Type:	Fresh Water			Fluid Gradient:	0.433	*psi/ft*
Hydrostatic:	482	*psi*		Fracture Gradient:	1.09	*psi/ft*
Maximum STP:	[Frac Gradient – Fluid Gradient] x Mid Perf Depth:				731	*psi*

Test Data

Time of Day (24 hr) (hh:mm)	Δt (min)	Tank Fluid Level (inches)	Injection Rate (gpm)	Injection Pressure (psi)	Comments
09:15	0	32 5/8 93.49 gals	.019	371	Start injection
09:30	15	32 7/16 96.27 gals	0.19	383	
09:45	30	31 1/2 110.15 gals	0.93	600	Pressure increased
10:00	45	28 1/2 154.58 gals	2.96	650	
10:15	60	26 -- 191.61 gals	2.47	729	
10:45	90	23 3/16 233.26 gals	2.78	719	9 minute tank fill
11:15	120	31 9/16 319.06 gals	2.86	717	
11:45	150	26 1/8 399.59 gals	2.68	715	
12:15	180	20 3/4 479.19 gals	2.65	712	4 minute tank fill
12:45	210	23 3/16 561.57 gals	2.75	694	
13:15	240	18 1/2 630.99 gals	2.31	695	Conclude injection
Test Totals		631 gals			
Average			2.63 gpm	692 psi	

Additional Test Information:

Monday May 3, 2004

13:00 On location

17:00 RU PermPT

18:10 Breakdown started, no breakdown noted. Pumped 93 gals @ 2.6 gpm, 650 psi

18:40 Shut in well ISIP = 650 psi

Tuesday May 4, 2004

08:30 On site rigging up

09:00 Filled tbg and found leaks in connection.

09:10 Pressure tested, no leaks

09:15 Began injection test, no break down noted

Pinnacle Technologies PermPT Data Sheet
Test Date: May 5, 2004

Well Name:	Hon #9				
Operator:	Royal Drilling & Producing				
Perforations:	1066-1068 ft		Total Perf's:	2	*ft*
Fluid Type:	Fresh Water		Fluid Gradient:	0.433	*psi/ft*
Hydrostatic:	462	*psi*	Fracture Gradient:	1.68	*psi/ft*
Maximum STP:	[Frac Gradient – Fluid Gradient] x Mid Perf Depth:			1,330	*psi*

Test Data

Time of Day (24 hr) (hh:mm)	Δt (min)	Tank Fluid Level (inches)	Injection Rate (gpm)	Injection Pressure (psi)	Comments
17:00	0	37 --		774	Start injection
17:15	15	36 7/8 1.85 gals	0.12	912	Pressure increased
17:30	30	36 1/2 7.4 gals	1.11	1324	Pressure increased
17:45	45	35 5/16 24.99gals	1.17	1220	
18:00	60	34 1/8 42.58 gals	1.17	1197	
18:30	90	31 5/8 79.61 gals	1.23	1161	
19:00	120	29 -- 110.49 gals	1.30	1135	
19:30	150	26 1/4 159.22 gals	1.36	1116	
20:00	180	23 7/16 200.87 gals	1.39	1094	
20:30	210	20 3/8 246.23 gals	1.51	1081	
21:00	240	17 1/4 292.51 gals	1.54	1070	Conclude injection
Test Totals		293 gals			
Average			1.22 gpm	1131 psi	

Additional Test Information:

13:00 On location

15:25 Breakdown started.

15:42 Breakdown 2,000 psi to 1,550 psi to 1,250 psi, Pumped 47.21 gals @ 3.15 gpm, 1,250 psi

15:50 Shut in well ISIP = 1,300 psi

17:00 Began injection test, no break down noted

21:00 Downhole valve closed. Increased surface pressure to 1,568 psi.

BHP pressure gauges at 1,051 & 1,052 ft

Pinnacle on-site supervisors: Brian Laging and Steve Wolfe

Pinnacle Technologies PermPT Data Sheet
Test Date: May 6, 2004

Well Name:	Hon #9				
Operator:	Royal Drilling & Producing				
Perforations:	996-1000 ft		Total Perf's:	2	*ft*
Fluid Type:	Fresh Water		Fluid Gradient:	0.433	*psi/ft*
Hydrostatic:	432	*psi*	Fracture Gradient:	1.64	*psi/ft*
Maximum STP:	[Frac Gradient – Fluid Gradient] x Mid Perf Depth:			1205	*psi*

Test Data

Time of Day (24 hr) (hh:mm)	Δt (min)	Tank Fluid Level (inches)	Injection Rate (gpm)	Injection Pressure (psi)	Comments
16:00	0	36 15/16		600	Start injection
16:15	15	36 3/8 8.33 gals	0.56	701	Pressure increased
16:30	30	36 1/8 12.03 gals	0.25	716	
16:45	45	35 13/16 16.66 gals	0.31	726	
17:00	60	35 1/2 21.29 gals	0.31	734	
17:30	90	34 15/16 29.62 gals	0.28	746	
18:00	120	34 3/8 37.95 gals	0.28	755	
18:30	150	33 13/16 46.28 gals	0.28	761	
19:00	180	33 1/4 54.61 gals	0.28	761	
19:30	210	32 11/16 62.94 gals	0.28	771	
20:00	240	32 1/8 71.27 gals	0.28	775	Conclude injection
Test Totals		71 gals			
Average			0.30 gpm	731 psi	

Additional Test Information:

12:30 On location
14:52 Begin breakdown
15:07 Breakdown 1,450 psi to 750 psi, Pumped 25.9 gals @ 2.59 gpm, 900 psi to 1,200 psi
15:17 Shut in well ISIP = 643 psi
16:00 Began injection test
21:00 Toolhand accidentally released the packer
BHP pressure gauges at 967 & 968 ft, plug reset to 1,025 ft

Pinnacle on-site supervisors: Brian Laging and Steve Wolfe

Pinnacle Technologies PermPT Data Sheet
Test Date: May 7, 2004

Well Name:	Hon #9				
Operator:	Royal Drilling & Producing				
Perforations:	882 to 886 ft		Total Perf's:	4	*ft*
Fluid Type:	Fresh Water		Fluid Gradient:	0.433	*psi/ft*
Hydrostatic:	383	*psi*	Fracture Gradient:	1.38	*psi/ft*
Maximum STP:	[Frac Gradient – Fluid Gradient] x Mid Perf Depth:			837	*psi*

Test Data

Time of Day (24 hr) (hh:mm)	Δt (min)	Tank Fluid Level (inches)	Injection Rate (gpm)	Injection Pressure (psi)	Comments
09:45	0	37 7/8 16.66 gals	0.19	650	Start injection
10:00	15	37 11/16 19.44 gals	0.19	675	Pressure increased
10:15	30	37 1/2 22.22 gals	0.19	744	Pressure increased
10:30	45	36 1/2 20.37 gals	0.99	780	
10:45	60	35 1/8 40.73 gals	1.36	810	
11:15	90	32 3/4 75.90 gals	1.17	806	
11:45	120	30 3/8 111.07 gals	1.17	806	
12:15	150	27 15/16 147.17 gals	1.20	811	
12:45	180	25 1/2 183.27 gals	1.20	818	
13:15	210	23 -- 220.17 gals	1.23	825	
13:45	240	20 1/2 257.07 gals	1.23	831	Conclude injection
Test Totals		257 gals			
Average			1.07 gpm	778 psi	

Additional Test Information:

Friday May 7, 2004

06:45 On location

08:32 Breakdown from 1,450 psi to 750. Pumped 16.7 gals @ 1.67 gpm, 750 psi

08:42 Shut in well ISIP = 650 psi

09:45 Began injection potion of test

13:45 Downhole valve closed. Surface pressure increased 1,700 psi.

BHP pressure gauges at 871 & 872 ft

Pinnacle on-site supervisors: Brian Laging and Steve Wolfe

Pinnacle Technologies PermPT Data Sheet
Test Date: May 8, 2004

Well Name:	Hon #9					
Operator:	Royal Drilling & Producing					
Perforations:	805 to 810 ft			Total Perf's:	5	*ft*
Fluid Type:	Fresh Water		Fluid Gradient:		0.433	*psi/ft*
Hydrostatic:	350	*psi*	Fracture Gradient:		1.69	*psi/ft*
Maximum STP:	[Frac Gradient – Fluid Gradient] x Mid Perf Depth:				1,015	*psi*

Test Data

Time of Day (24 hr) (hh:mm)	Δt (min)	Tank Fluid Level (inches)	Injection Rate (gpm)	Injection Pressure (psi)	Comments
10:15	0	38 9/16		600	Start injection
10:30	15	38 -- 8.33 gals	0.56	757	
10:45	30	37 1/2 15.73 gals	0.49	801	Pressure increased
11:00	45	35 1/8 50.90 gals	2.34	922	
11:15	60	32 3/4 86.07 gals	2.34	946	Pressure decreased
11:45	90	28 7/8 143.46 gals	1.91	927	
12:15	120	25 5/8 194.3 gals	1.60	957	5 minute tank fill
12:45	150	31 1/2 236.88 gals	1.70	985	
13:15	180	27 7/8 290.57 gals	1.79	999	
13:45	210	24 1/4 344.26 gals	1.79	1007	
14:15	240	20 9/16 398.87 gals	1.82	1013	Conclude injection
Test Totals		399 gals			
Average			1.67 gpm	901 psi	

Additional Test Information:

06:45 On location

09:57 Breakdown started, no breakdown noted. Pumped 9.3 gals @ 1.86 gpm, 750 psi

18:40 Shut in well ISIP = 550 psi

10:15 Began injection test, no break down noted

14:20 Downhole valve closed. Increased surface pressure to 1,800 psi.

BHP pressure gauges at 808 ft

Pinnacle on-site supervisors: Brian Laging and Steve Wolfe

Appendix 5b. Pressure Transient Testing Results for Hon #3 by Pinnacle Technologies

Pinnacle

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Suite 102
Centennial, CO 80112
Ph: 720-344-3464
Fax: 303-766-4306
www.pinntech.com

Injection Falloff Test Results For Royal Drilling & Producing Hon #3 CBM Test Well White County, Illinois Final Report

Submitted to:

Royal Drilling & Producing
Crossville, Illinois
&
Illinois State Geological Survey
Champaign, Illinois

May 2004

Houston 281-876-2323
San Francisco 415-861-1097
Bakersfield 661-335-7711
Denver 720-344-3464
Delft 31-15-219-0062
Reynosa 52-892-42191
Calgary 403-863-8458

Hon #3 Injection/Falloff Test Results

Table of Contents

[Perforations: 812 ft to 816 ft]
Test #1R Surface Injection Test Data
[Perforations: 888 ft to 892 ft]
Test #2R Surface Injection Test Data
[Perforations: 812 ft to 816 ft]

Executive Summary

Pinnacle Technologies, Inc. (Pinnacle), conducted four injection/falloff tests in a wellbore located in White County, Illinois for Royal Drilling & Producing, Inc. Two individual perforated intervals each tested twice. This report discusses the work performed in the Hon #3 wellbore. The purpose of the work was to determine in-situ permeability to water in multiple coal seam intervals.

Pinnacle used its Kansas based injection/falloff PermPT equipment to perform the tests. The injection unit is capable of very low rate – high-pressure injection necessary for injection falloff testing in coal seams. Bottom hole pressure measurement was used for all tests performed, with surface injection rates measured at the injection unit. Fracture gradients of 1.17 psi/ft to 1.78 psi/ft based on breakdowns conducted prior to each injection test was used to determine maximum surface injection pressures.

Test Results:
Two coal seams were tested in this wellbore. Results of the injection/falloff testing in Hon #3 wellbore are as follows:

Test Name	Perforated Interval (ft)	Net Pay (ft)	Permeability (mD)	Transmissivity (mD·ft/cp)	Skin Factor (Dimensionless)	Average Pressure (psi)
Test 1R	888-92	4	261	996.1	+25.8	932
Test 2R	812-16	4	0.99	3.7	-5.1	405

Four injection tests were pumped in the Hon #3 wellbore. The first test conducted in each perforated interval exhibited a pressure leak or lack of pressure integrity in the system. These system leaks appeared to be a result of downhole mechanical problems. The problem(s) were not rectified in the deepest perforated interval (888-892 ft) but were eliminated in the shallower interval tested (812-16 ft). **The retest in the shallow interval (812-16 ft) is considered to be the only representative permeability test in this wellbore.**

The first injection/falloff test was conducted in a coal seam having a perforated thickness of 4 ft. For the permeability test, fresh water was injected for 4.0 hours at an average rate of 2.04 gallons per minute and surface injection pressure of 793 psi. The well was shut-in downhole with a mechanical in-line ball valve and allowed to falloff overnight.

The falloff pressure behavior in the first test conducted indicated significant lack of downhole mechanical pressure integrity. Bottom hole pressure remained well above the hydrostatic pressure of a full column of fresh water and essentially did not leak off into the reservoir. Analysis of the pressure data is not reported due to the lack of mechanical pressure integrity in the system.

The second injection/falloff test was conducted in a coal seam having a perforated thickness of 4 ft. For the permeability test, fresh water was injected for 4.0 hours at an average rate of 0.21 gallons per minute and surface injection pressure of 519 psi. The well was shut-in downhole with a mechanical in-line ball valve and allowed to falloff overnight.

The falloff pressure behavior in the second test conducted again indicated a lack of downhole mechanical pressure integrity. Bottom hole pressure remained well above the hydrostatic pressure of a full column of fresh water. Although some leakoff was recorded, it did not have the characteristics of reservoir leakoff.

Analysis of the pressure data is not reported due to the lack of mechanical pressure integrity in the system.

The third injection/falloff test was a retest of the 888-96 ft interval. The perforated thickness remained 4 ft. For the permeability test, fresh water was injected for 4.0 hours at an average rate of 1.71 gallons per minute and surface injection pressure of 838 psi. The well was shut-in downhole with a mechanical in-line ball valve and allowed to falloff for 15.9 hours.

Although the falloff pressure exhibited identical behavior to that of the first test conducted in this interval, an analysis was performed. Using 4.0 ft of net pay, analysis of the pressure falloff data with a single-phase, radial composite pressure transient analysis program resulted in reservoir coal seam permeability to water of 261.3 mD and 33.8 mD, respectively. The inner (261.3 mD) interval is estimated to have a radius of 152 ft from the wellbore and a corresponding outer radius of 1,000+ ft for the 33.8 mD region. The calculated skin was +25.8 indicating a significant amount of near-wellbore damage.

The fourth injection/falloff test was a retest of the 812-16 ft interval. The perforated thickness remained 4 ft. For the permeability test, fresh water was injected for 4.0 hours at an average rate of 0.30 gallons per minute and surface injection pressure of 557 psi. The well was shut-in downhole with a mechanical in-line ball valve and allowed to falloff for 42.5 hours.

Unlike the first test conducted in this interval, the falloff period produced a quality data set for analysis. Using 4.0 ft of net pay, analysis of the pressure falloff data with a single-phase, radial composite pressure transient analysis program resulted in reservoir coal seam permeability to water of 0.99 mD and 0.34 mD, respectively. Tthe inner (0.99 mD) interval is estimated to have a radius of 69 ft from the wellbore and a corresponding outer radius of 1,000+ ft for the 0.34 mD region. The calculated skin was –5.1 indicating a significant amount of near-wellbore face cleat permeability.

Background

The Illinois State Geological Survey and Royal Drilling & Producing, Inc. contracted Pinnacle Technologies to test the in-situ permeability in multiple coal seams in the Hon #3 wellbore near the town of Grayville, Illinois. Pinnacle Technologies supplied the pumping equipment, rate and pressure measurement, and personnel required for testing. Contractors for Royal Drilling & Producing conducted all other work beyond the injection/falloff testing.

Reservoir parameters used for the Hon #3 in all data analyses are outlined below in the following table. Only the retest data is presented in the table, as the original tests in the wellbore did not result in analyzable pressure data sets.

Pertinent Reservoir Data

Parameter	Perm Test #1	Perm Test #2
Perforated Thickness, ft	4	4
Depth to Coal Seam, ft	888	812
Mid Depth of Coal, ft	890	814
Skin Factor, dimensionless	+25.8	-5.1
Water Density, lb/ft^3	62.4	62.4
Tubing I.D., inches	1.995	1.995
Tubing Capacity, gal/ft	0.1624	0.1624
Casing I.D., inches	6.456	6.456
Casing Capacity, gal/ft	1.7001	1.7001
Water Viscosity, cp	1.05	1.07
Water Formation Volume,	1.02	1.02
Coal Porosity, %	1.5	1.5
Water Compressibility, psi^{-1}	3.6 e^{-6}	3.6 e^{-6}
Wellbore Radius, ft	0.3698	0.3698

Field Operations Summary

- Arrive on location and spot PermPT equipment. Conduct safety meeting and review job procedures and expectations with all personnel on location.

- Nipple up wellhead connections, pressure test surface injection lines to 2,000 psi. Inject into perforations for 5 minutes then cease pumping. Record breakdown pressure (if no breakdown noted, continue pumping), ISIP, and 60-minute falloff data. Calculate pertinent injection test parameters based on the breakdown data. If no breakdown noted, continue with next step.

- Inject into the target coal seam for at least 4 hours and record surface injection rates and injection pressures.

- Shut-in well downhole for minimum of 16 hours by rotating the tubing to actuate the in-line ball valve located in tubing string above the packer. Disconnect PermPT equipment following conclusion of injection portion of test.

- Nipple down wellhead connections and prepare to test next coal interval after moving bridge plug/packer downhole assembly.

- Nipple up wellhead and repeat test procedures. Repeat perforating, bridge plug/packer setting, breakdown, and injection/falloff procedures for all target intervals.

- Nipple down wellhead assembly and demobilize PermPT equipment. Clean up and secure location for future completion work.

Test Results Summary

Test #1

Date Tested:	May 11, 2004
Perforations:	888-892 ft
Surface Breakdown Pressure:	1,200 psi
Estimated Reservoir Pressure:	NA
Radius of Investigation:	NA
Reservoir Permeability ***(to water)***:	NA (4.0 ft net pay)
Transmissivity:	NA
Skin Factor:	NA

Test Comments: Falloff data indicated lack of downhole pressure integrity. Test considered a failure.

Test #2

Date Tested:	May 12, 2004
Perforations:	812-816 ft
Surface Breakdown Pressure:	600 psi
Estimated Reservoir Pressure:	NA
Radius of Investigation:	NA
Reservoir Permeability ***(to water)***:	NA (4.0 ft net pay)
Transmissivity:	NA
Skin Factor:	NA

Test Comments: Falloff data indicated lack of downhole pressure integrity. Test considered a failure.

Test #1 Retest

Date Tested:	May 13, 2004
Perforations:	888-892 ft
Surface Breakdown Pressure:	1,200 psi
Estimated Reservoir Pressure:	932 psi
Radius of Investigation:	442 ft
Reservoir Permeability ***(to water)***:	261.1 mD (4.0 ft net pay)
Transmissivity:	936.1 mD·ft/cp
Skin Factor:	+25.8

Test Comments: Falloff data indicated lack of downhole pressure integrity. Permeability not considered valid.

Test #2 Retest

Date Tested:	May 15, 2004
Perforations:	812-816 ft
Surface Breakdown Pressure:	600 psi
Estimated Reservoir Pressure:	405 psi
Radius of Investigation:	116 ft
Reservoir Permeability ***(to water)***:	0.99 mD (4.0 ft net pay)
Transmissivity:	3.7 mD·ft/cp
Skin Factor:	-5.1

Test Comments: Test conducted with surface shut-in and no complications.

Conclusions

1. Both tests pumped in the interval 888-892 ft exhibited atypical reservoir falloff behavior. The falloff behavior of both tests is identical when compared on the same time and pressure scales. This suggests a mechanical problem downhole.

2. Small initial (>15 gallons) injections into the perforated interval (888-892 ft) produced typical reservoir leakoff characteristics. However, the falloff behaviors following the 4-hour injection period exhibit behavior not at all like that of a reservoir.

3. The first injection into the shallow interval from 812-816 ft resulted in a lack of downhole pressure integrity and thus was not analyzed. The problem was eliminated in the retest by not using the in-line mechanical ball valve. The test was accomplished by shutting in the well at the surface at the conclusion of the injection period. This provided a quality data set for analysis.

4. Falloff pressure in all four tests conducted in the Hon #3 well did not decline to anywhere near that of hydrostatic column of water. This suggests that a limited reservoir area was tested and the injection volumes inflated the coal seam and pressure was unable to dissipate into the far-field reservoir.

5. Hydraulic fracturing may be required for commercial production. The measured permeabilities are likely pressure dependent and placing proppant in the near-wellbore region will aid in retaining a connection to the far-field reservoir.

Injection Testing Recommendations

1. Continued testing throughout the development of this project will aid in optimizing completions and help focus on the commercial coal intervals.

2. Conduct permeability testing on select seams throughout the development phase of the field in order to optimize completion practices. Additionally, permeability testing can help define optimum well spacing in the field.

3. Following completion of the wells and sufficient production testing, pressure transient testing should again be conducted to ascertain effective reservoir permeability after dewatering.

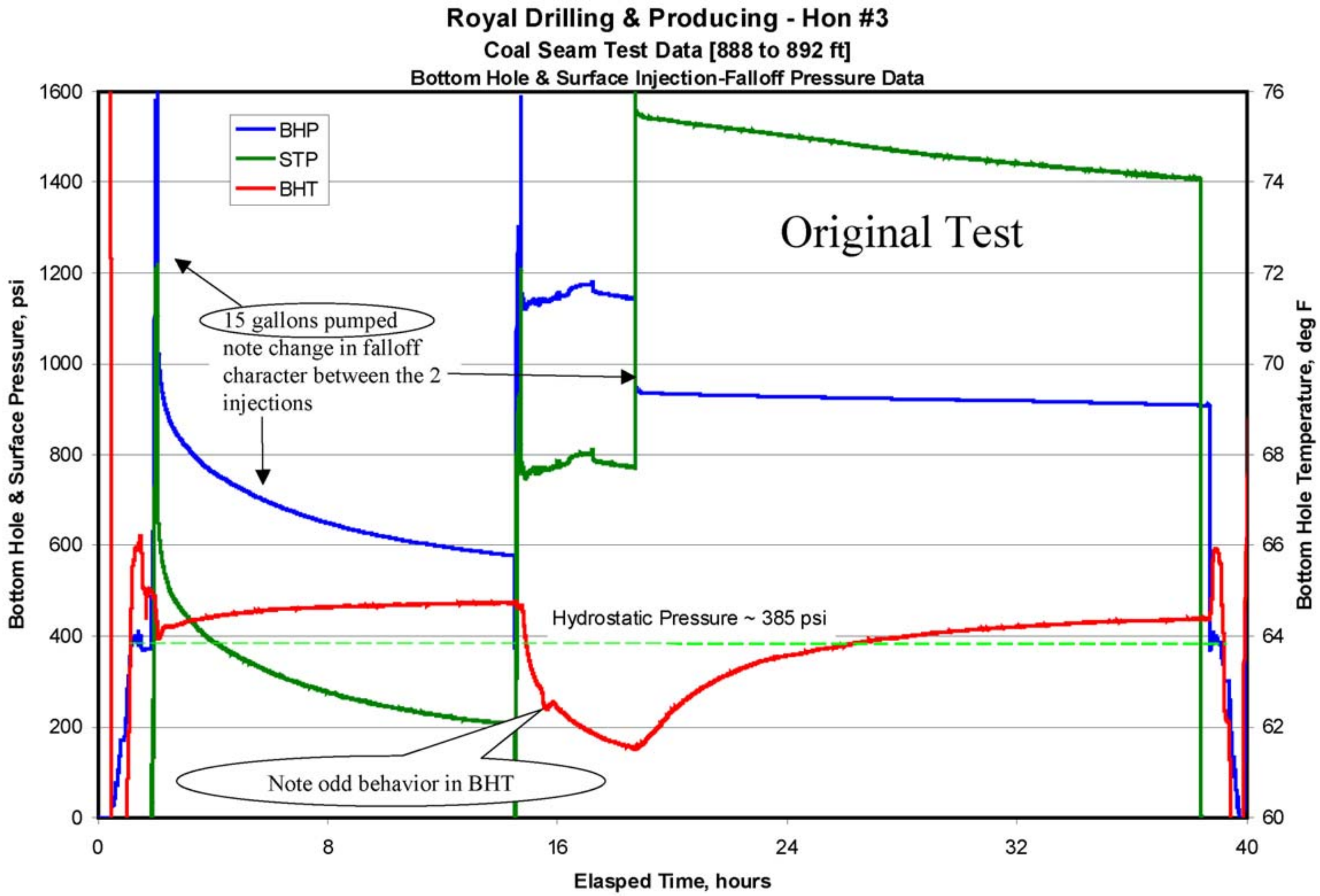
Hon #3 Injection-Falloff Testing Results

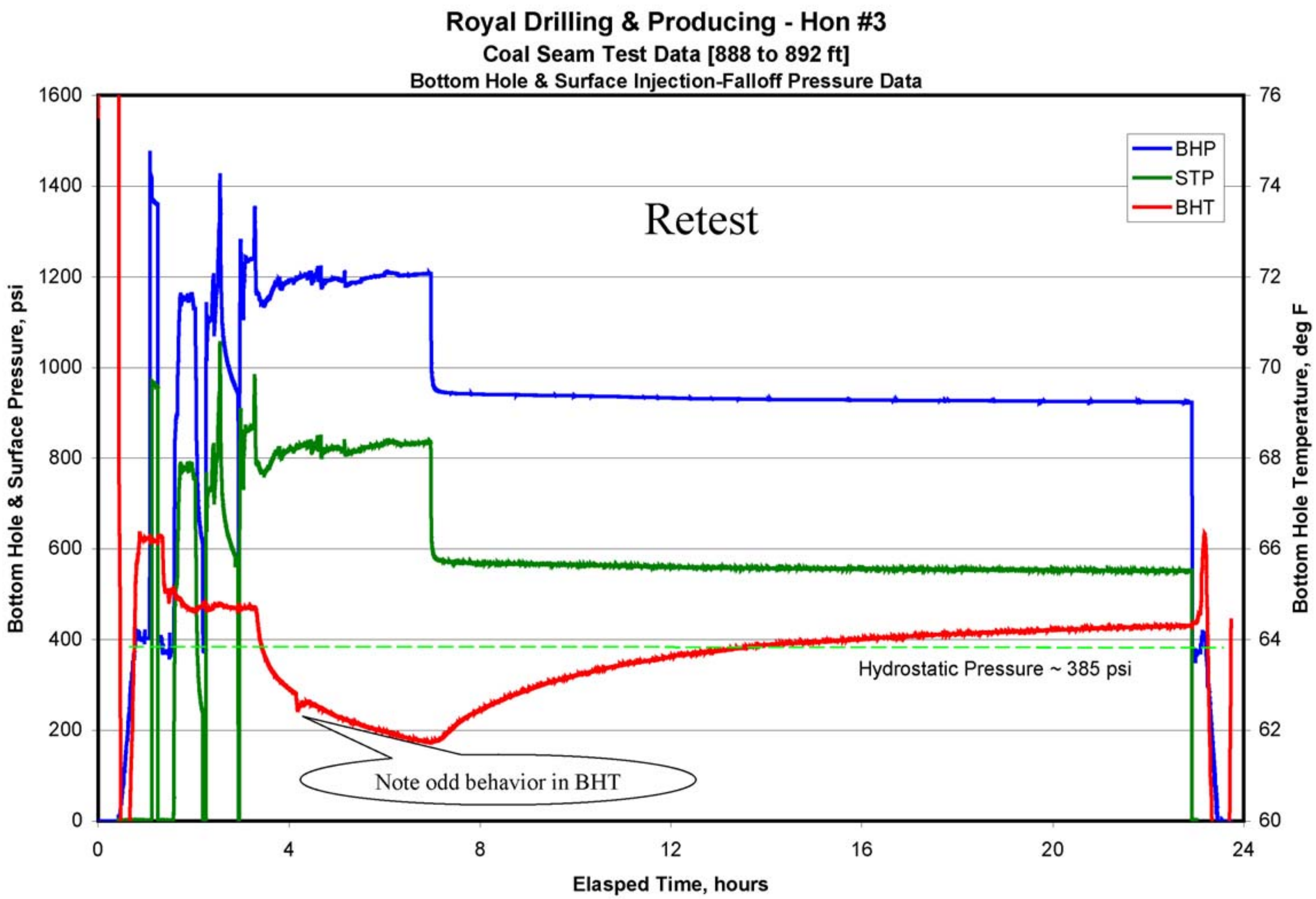
Well Name / Interval	Perforation Depth (ft)	Calculated Permeability (mD)	Calculated Avg Reservoir Pressure (psi)	Test Radius of Investigation (ft)	Skin Factor
Test 1	888-892 (4' net)	261	932 (1.05 psi/ft)	442	25.8
Test 2	812-816 (4' net)	1.0	405 (0.50 psi/ft)	116	-5.1

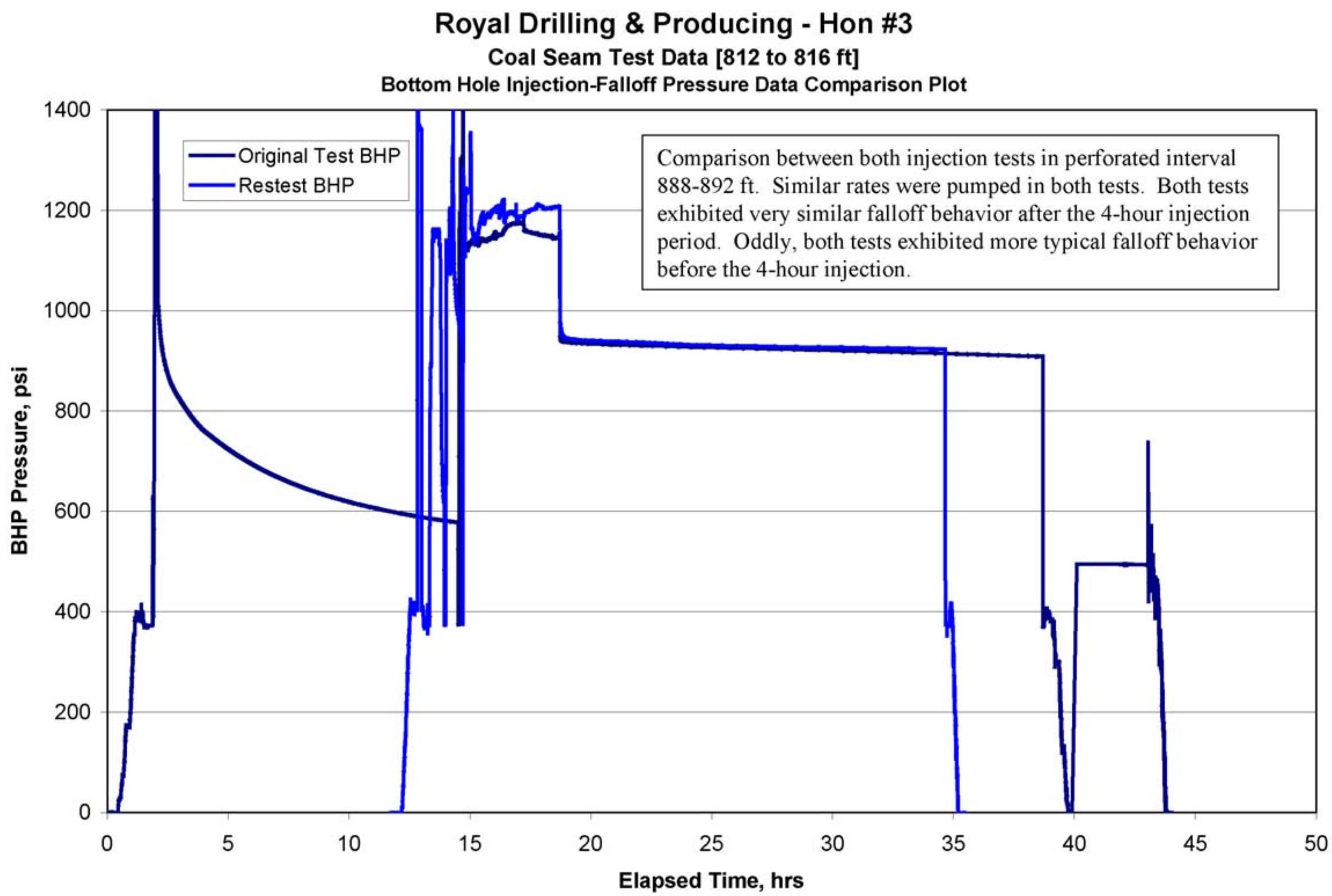
Results presented above are from the second test of each interval. Test #1 is most likely erroneous due to a mechanical leak evident in both data sets from the same perforated interval. This leak in the system could not be identified.

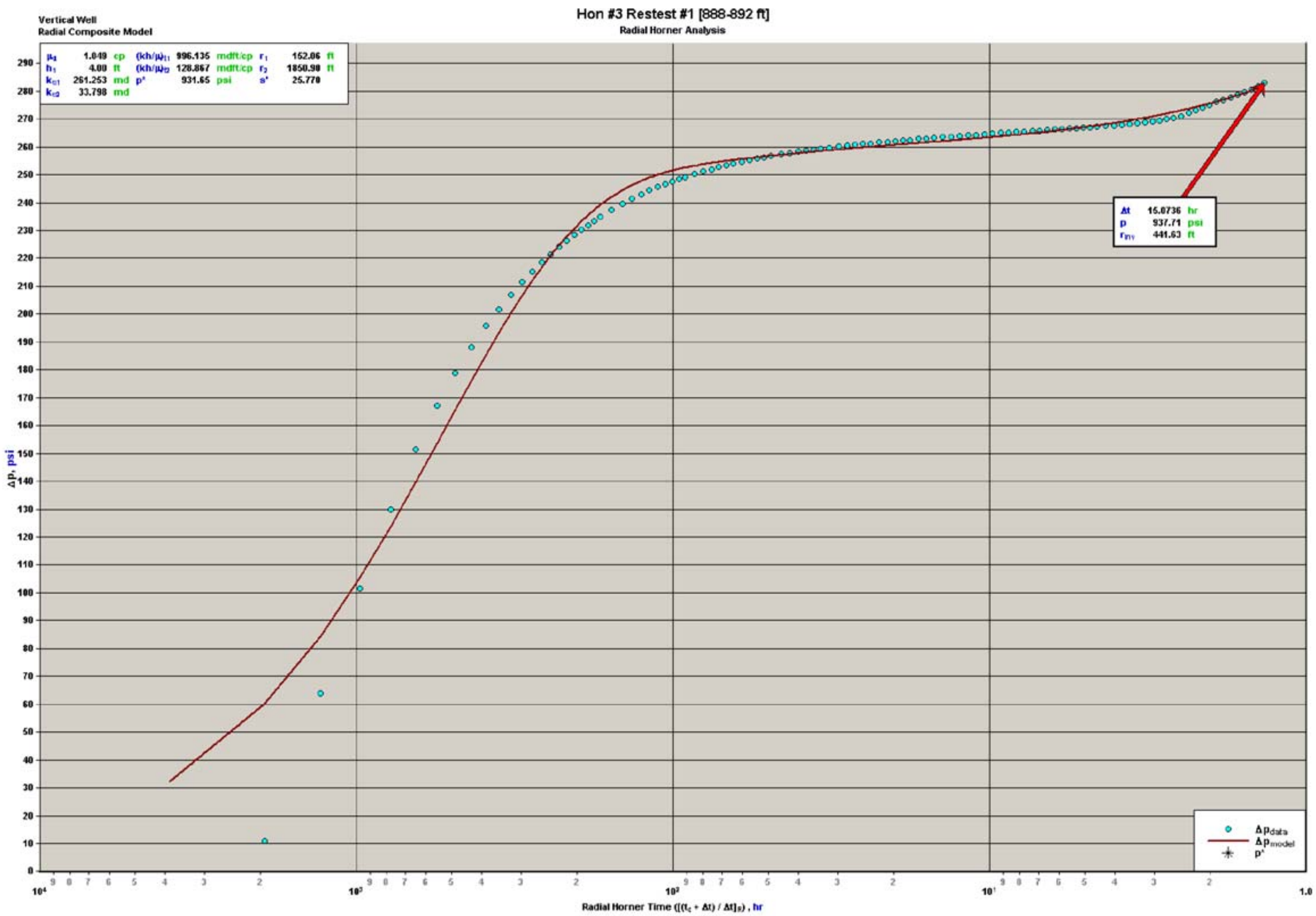
Test #2 experienced a downhole leak in the system in the original test but was rectified in the retest. The results presented above are considered accurate.

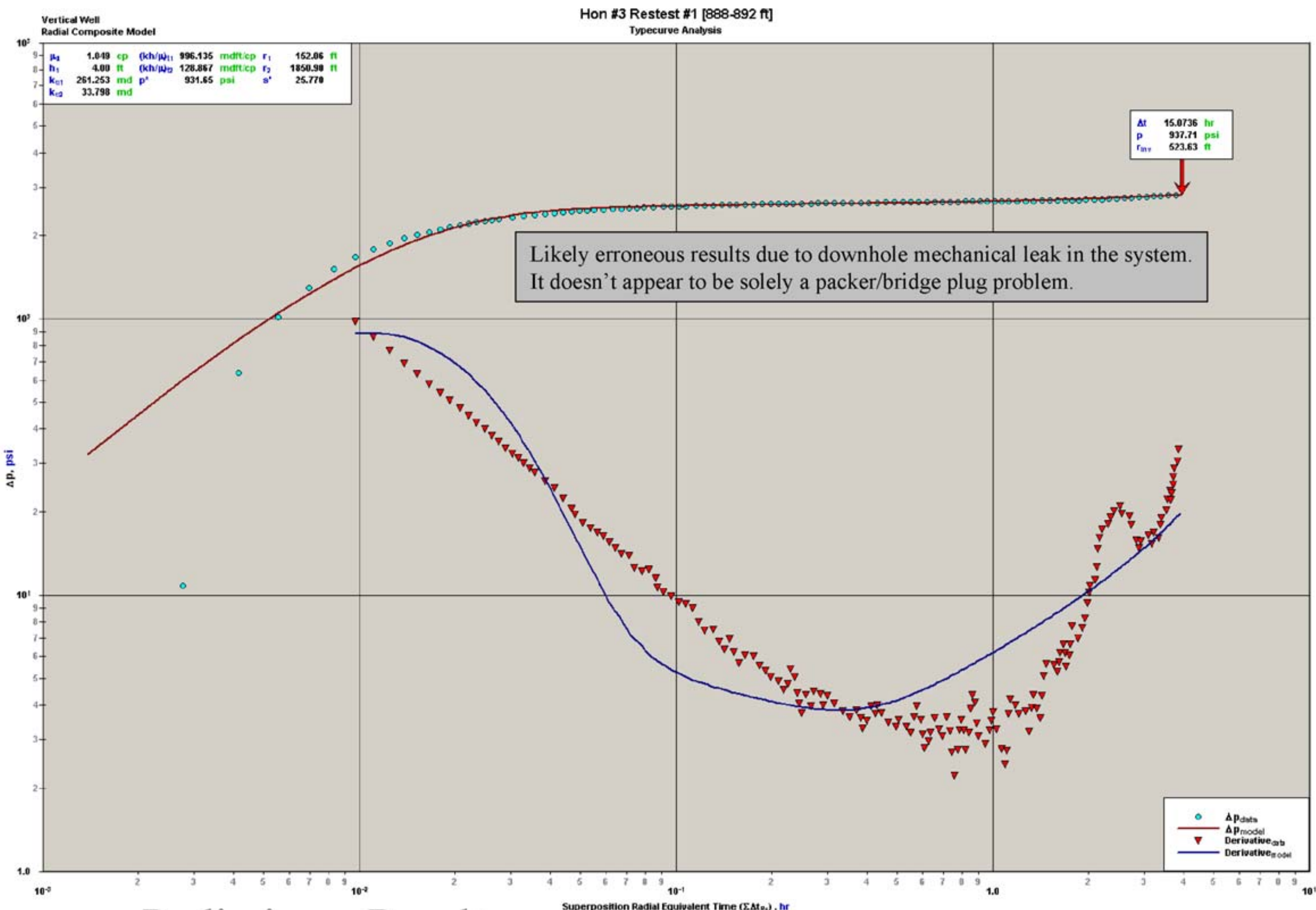
Also note that all tests in this wellbore failed to leakoff to near hydrostatic pressure suggesting an inflation of the coal seam with the 4-hour injection period. This phenomenon suggests limited reservoir area.


Royal Drilling & Producing - Hon #3
Coal Seam Test Data [888 to 892 ft]
Bottom Hole & Surface Injection-Falloff Pressure Data
BHP
STP
BHT
Original Test
15 gallons pumped
note change in falloff
character between the 2
injections
Hydrostatic Pressure ~ 385 psi
Note odd behavior in BHT
Bottom Hole & Surface Pressure, psi
Bottom Hole Temperature, deg F
Elasped Time, hours
0
200
400
600
800
1000
1200
1400
1600
60
62
64
66
68
70
72
74
76
0
8
16
24
32
40

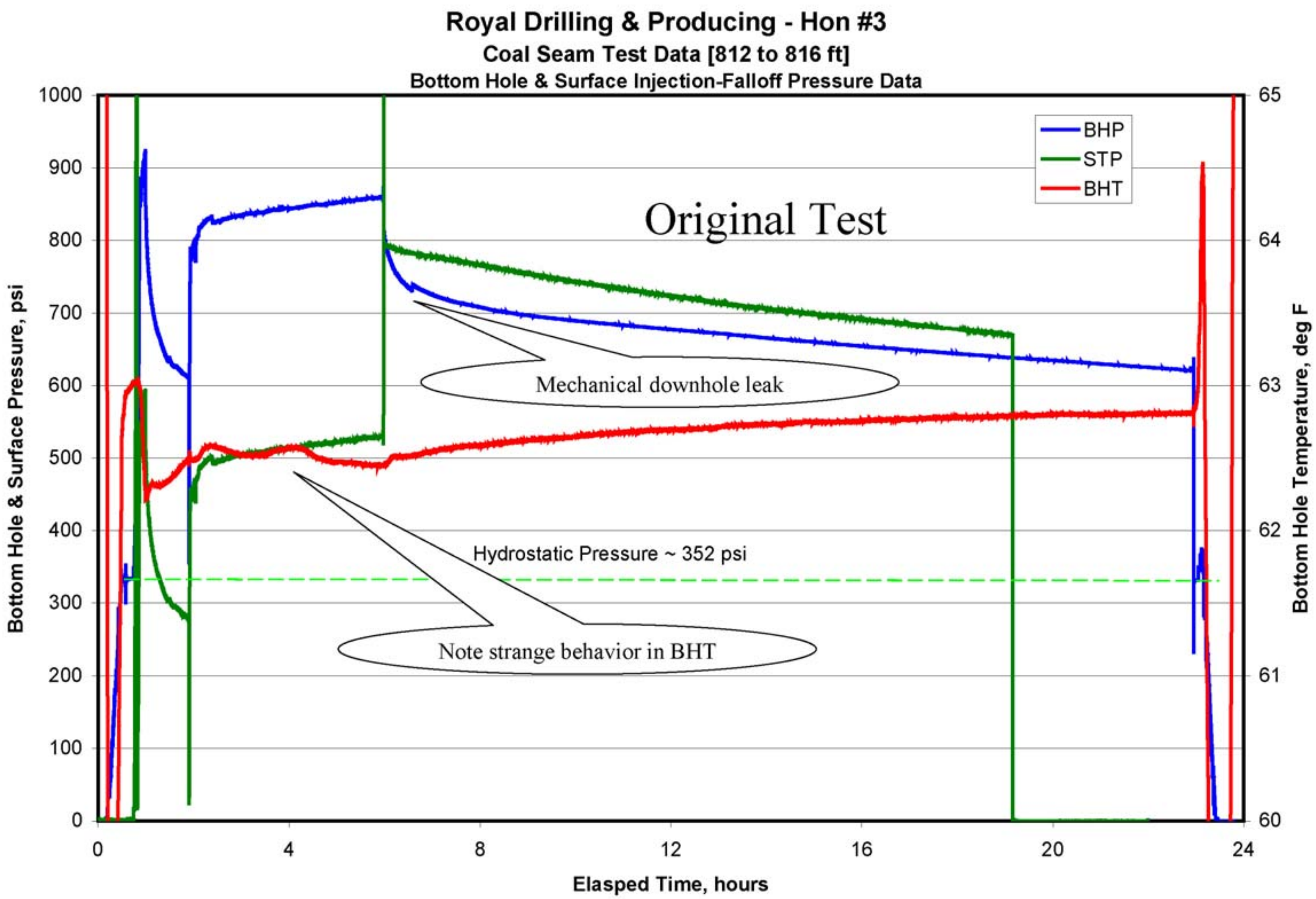

Royal Drilling & Producing - Hon #3
Coal Seam Test Data [888 to 892 ft]
Bottom Hole & Surface Injection-Falloff Pressure Data
Retest
BHP
STP
BHT
Hydrostatic Pressure ~ 385 psi
Note odd behavior in BHT
Bottom Hole & Surface Pressure, psi
Bottom Hole Temperature, deg F
Elasped Time, hours
0
200
400
600
800
1000
1200
1400
1600
60
62
64
66
68
70
72
74
76
0
4
8
12
16
20
24

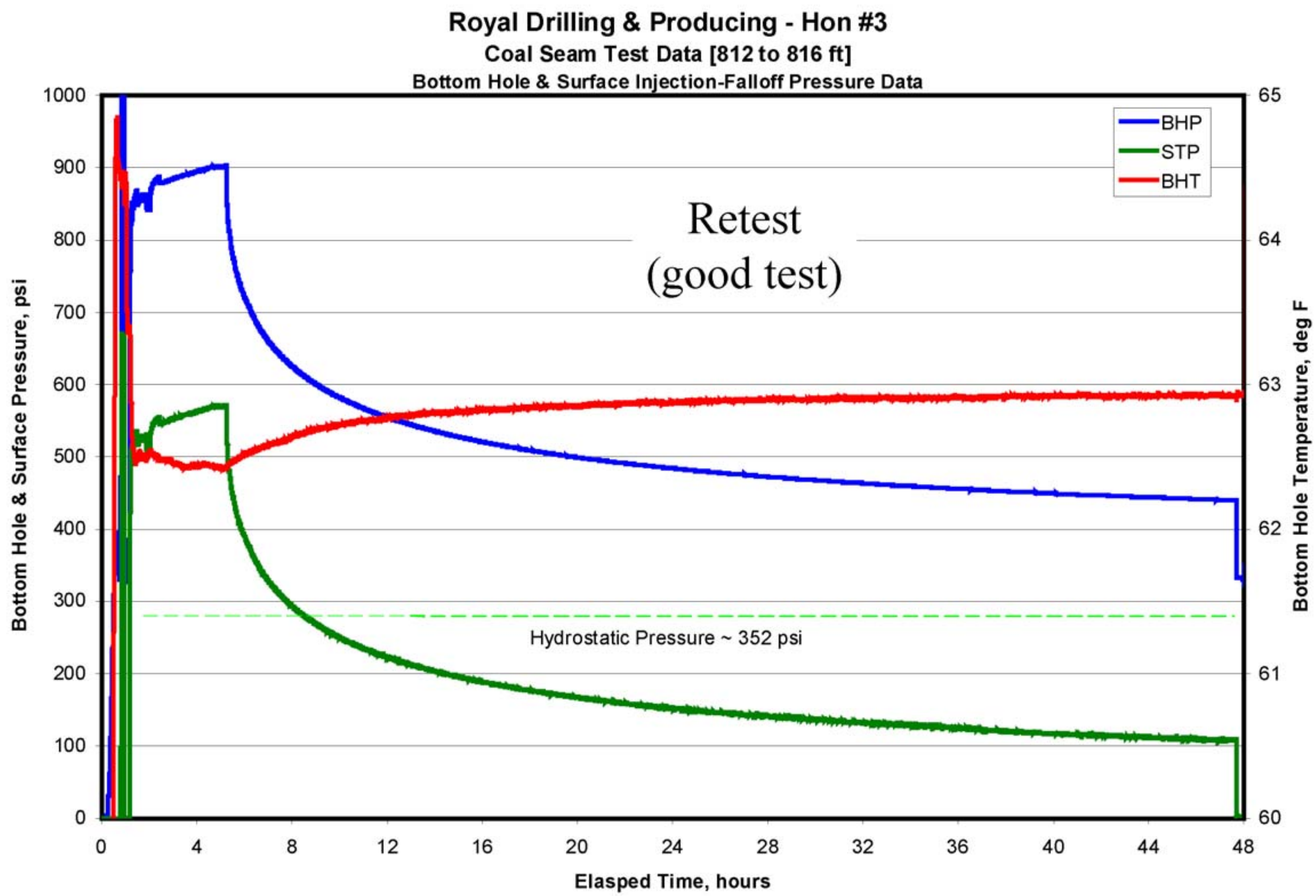

Royal Drilling & Producing - Hon #3
Coal Seam Test Data [812 to 816 ft]
Bottom Hole Injection-Falloff Pressure Data Comparison Plot
Original Test BHP
Restest BHP
Comparison between both injection tests in perforated interval 888-892 ft. Similar rates were pumped in both tests. Both tests exhibited very similar falloff behavior after the 4-hour injection period. Oddly, both tests exhibited more typical falloff behavior before the 4-hour injection.
BHP Pressure, psi
Elapsed Time, hrs
0
200
400
600
800
1000
1200
1400
0
5
10
15
20
25
30
35
40
45
50

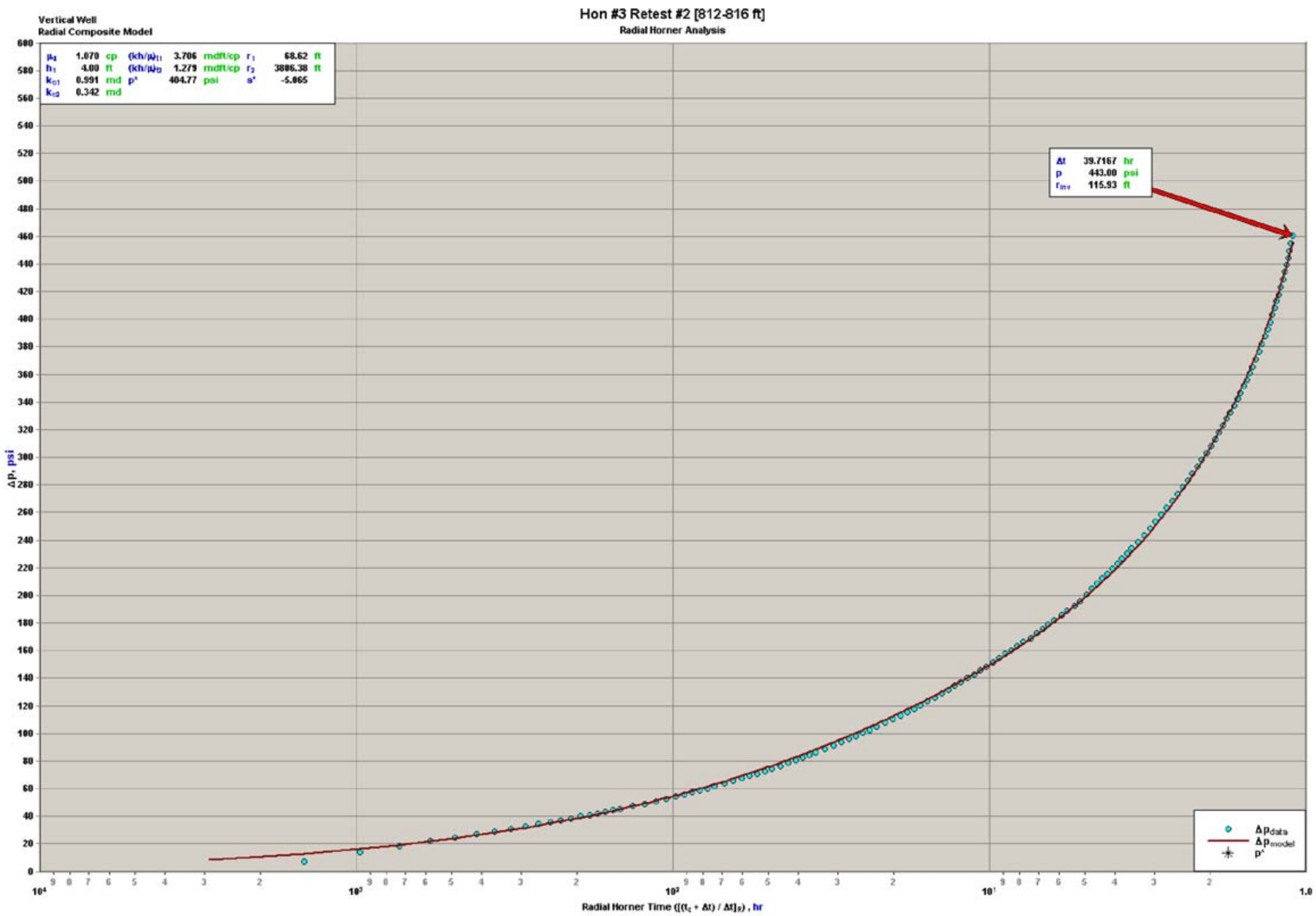

Hon #3 Restest #1 [888-892 ft]
Radial Horner Analysis
Vertical Well
Radial Composite Model
μ1 1.049 cp (kh/μ)t1 996.135 mdft/cp r1 152.06 ft
h1 4.00 ft (kh/μ)t2 128.867 mdft/cp r2 1850.90 ft
kt1 261.253 md p* 931.65 psi s' 25.770
kt2 33.798 md
Δt 15.0736 hr
p 937.71 psi
rinv 441.63 ft
Δpdata
Δpmodel
p*
Δp, psi
Radial Horner Time ([(tc + Δt) / Δt]s) , hr

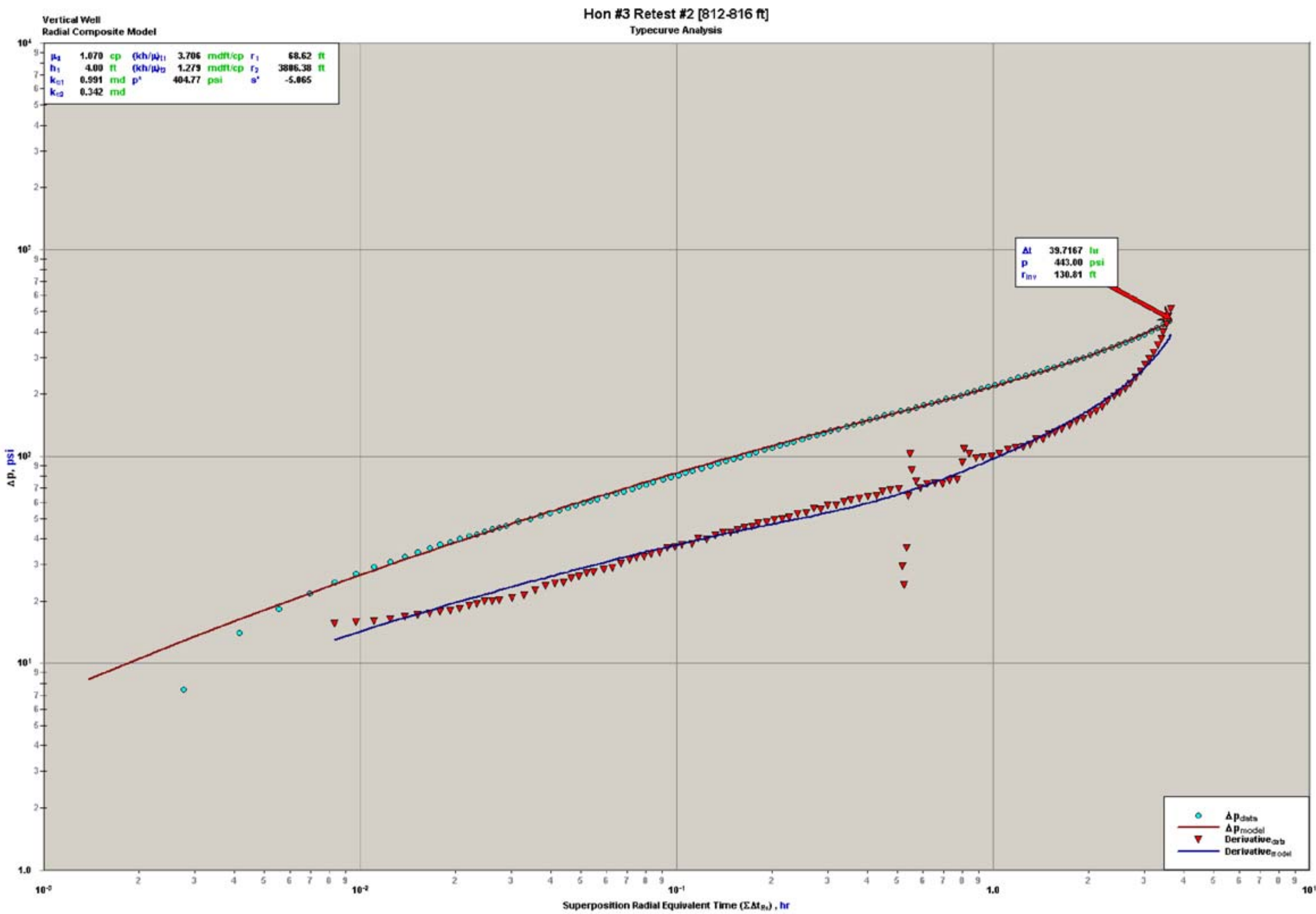


Preliminary Results


Royal Drilling & Producing - Hon #3
Coal Seam Test Data [812 to 816 ft]
Bottom Hole & Surface Injection-Falloff Pressure Data
BHP
STP
BHT
Original Test
Mechanical downhole leak
Hydrostatic Pressure ~ 352 psi
Note strange behavior in BHT
Bottom Hole & Surface Pressure, psi
Bottom Hole Temperature, deg F
Elasped Time, hours
0
100
200
300
400
500
600
700
800
900
1000
60
61
62
63
64
65
0
4
8
12
16
20
24


Royal Drilling & Producing - Hon #3
Coal Seam Test Data [812 to 816 ft]
Bottom Hole & Surface Injection-Falloff Pressure Data
BHP
STP
BHT
Retest
(good test)
Hydrostatic Pressure ~ 352 psi
Bottom Hole & Surface Pressure, psi
Bottom Hole Temperature, deg F
Elasped Time, hours
0
100
200
300
400
500
600
700
800
900
1000
60
61
62
63
64
65
0
4
8
12
16
20
24
28
32
36
40
44
48


Hon #3 Retest #2 [812-816 ft]
Radial Horner Analysis
Vertical Well
Radial Composite Model
μ 1.070 cp (kh/μ)t1 3.706 mdft/cp r1 68.62 ft
h1 4.00 ft (kh/μ)t2 1.279 mdft/cp r2 3806.38 ft
kt1 0.991 md p* 404.77 psi s' -5.065
kt2 0.342 md
Δt 39.7167 hr
p 443.00 psi
rinv 115.93 ft
Δp, psi
Radial Horner Time ([(tc + Δt) / Δt]s) , hr
Δpdata
Δpmodel
p*


Hon #3 Retest #2 [812-816 ft]
Typecurve Analysis
Vertical Well
Radial Composite Model
μ 1.070 cp (kh/μ)t1 3.706 mdft/cp r1 68.62 ft
h1 4.00 ft (kh/μ)t2 1.279 mdft/cp r2 3806.38 ft
kt1 0.991 md p* 404.77 psi s' -5.065
kt2 0.342 md
Δt 39.7167 hr
p 443.00 psi
rinv 130.81 ft
Δp, psi
Superposition Radial Equivalent Time (ΣΔtRe) , hr
Δpdata
Δpmodel
Derivativedata
Derivativemodel

Well Name:	Hon #3				5/11/04
Operator:	Royal Drilling & Producing				
Perforations:	888 to 892 ft		Total Perf's:	4	ft
Fluid Type:	Fresh Water		Fluid Gradient:	0.433	psi/ft
Hydrostatic:	385	psi	Fracture Gradient:	1.36	psi/ft
Maximum STP:	[Frac Gradient – Fluid Gradient] x Mid Perf Depth:			825	psi

Test Data					
Time of Day (24 hr) (hh:mm)	Δt (min)	Tank Fluid Level (inches)	Injection Rate (gpm)	Injection Pressure (psi)	Comments
07:15	0	37 13/16		807	Start injection
07:30	15	36 ---28.64 gals	1.79	772	
07:45	30	34 --58.19 gals	1.97	780	
08:00	45	31 15/16 88.74 gals	2.04	784	
08:15	60	29 15/16 118.29 gals	1.97	782	
08:45	90	25 3/4 180.31 gals	2.07	792	
09:15	120	21 5/8 241.40 gals	2.04	814	
09:45	150	17 9/16 301.57 gals	2.01	817	
10:15	180	32 1/16 363.67 gals	2.07	796	5 minute tank fill
10:45	210	27 3/4 427.54 gals	2.13	790	
11:15	240	23 1/2 490.48 gals	2.10	789	Conclude injection
Test Totals		490 gals			
Average			2.04 gpm	793 psi	

Monday May 10, 2004
07:00 On location
09:00 RU PermPT
18:29 Breakdown started, Breakdown from 1200 to 900 psi. <u>Pumped 15 gals @ 3.0 gpm, 900 psi</u>
18:40 Shut in well ISIP = 739 psi
Tuesday May 11, 2004
07:00 On site rigging up
07:15 Began injection test, Pressure increased from 650 psi to 1,200 psi broke to 780 psi.
11:15 Downhole valve closed. Increased surface pressure to 1,568 psi.
BHP pressure gauges at 875 ft Pinnacle on-site supervisor: Brian Laging

Well Name:	Hon #3				5/12/04
Operator:	Royal Drilling & Producing				
Perforations:	812 to 816 ft		Total Perf's:	4	ft
Fluid Type:	Fresh Water		Fluid Gradient:	0.433	psi/ft
Hydrostatic:	352	psi	Fracture Gradient:	1.17	psi/ft
Maximum STP:	[Frac Gradient – Fluid Gradient] x Mid Perf Depth:			600	psi

Test Data					
Time of Day (24 hr) (hh:mm)	Δt (min)	Tank Fluid Level (inches)	Injection Rate (gpm)	Injection Pressure (psi)	Comments
10:30	0	38 1/16 8.40 gals		460	Start injection
10:45	15	37 1/2 12.10gals	0.25	503	
11:00	30	373/16 16.73 gals	0.31	510	
11:15	45	37 -19.51 gals	0.19	514	
11:30	60	36 3/4 23.21 gals	0.25	518	
12:00	90	36 1/2 26.91 gals	0.25	522	
12:30	120	36 3/16 31.54 gals	0.15	528	
13:00	150	35 13/16 37.09 gals	0.19	533	
13:30	180	35 1/2 41.72 gals	0.15	536	
14:00	210	35 1/4 45.42 gals	0.25	539	
14:30	240	34 7/8 50.97 gals	0.19	544	Conclude injection
Test Totals		51 gals			
Average			0.21 gpm	519 psi	

06:45 On site rigging up
09:21 Breakdown started, no breakdown noted. Pumped 13.88 gals @ 2.78 gpm, 600 psi
09:35 Shut in well ISIP = 550 psi
09:15 Began injection test, no break down noted
14:35 Downhole valve closed. Increased surface pressure to 1,500 psi.
BHP pressure gauges at 779 ft　　Pinnacle on-site supervisor: Brian Laging

Well Name:	Hon #3				5/13/04
Operator:	Royal Drilling & Producing				
Perforations:	888 to 892 ft (repeat)		Total Perf's:	4	ft
Fluid Type:	Fresh Water		Fluid Gradient:	0.433	psi/ft
Hydrostatic:	385	psi	Fracture Gradient:	1.78	psi/ft
Maximum STP:	[Frac Gradient – Fluid Gradient] x Mid Perf Depth:			1,199	psi

Test Data

Time of Day (24 hr) (hh:mm)	Δt (min)	Tank Fluid Level (inches)	Injection Rate (gpm)	Injection Pressure (psi)	Comments
16:15	0	37 ¾		840	Start injection
16:30	15	37 ¾	0	881	Pressure increased
16:45	30	361/8 24.07 gals	1.60	783	
17:00	45	34 7/16 48.75 gals	1.67	826	
17:15	60	32 1/2 76.44 gals	1.91	831	
17:45	90	28 9/16 134.75 gals	1.94	850	
18:15	120	24 15/16 188.44 gals	1.79	840	
18:45	150	21 -246.75 gals	1.94	830	
19:15	180	17 3/16 303.21 gals	1.88	845	6 minute tank fill
19:45	210	24 1/16 349.49 gals	1.93	846	
20:15	240	20 -409.66 gals	2.01	850	Conclude injection
Test Totals		410 gals			
Average			1.71 gpm	838 psi	

11:30 On site rigging up
16:15 Began injection test, no break down noted
16:35 Pressure increased to 750 psi
21:15 Needle valve closed at surface
BHP pressure gauges at 875 ft

Pinnacle on-site supervisor: Brian Laging

Well Name:	Hon #3				5/15/04	
Operator:	Royal Drilling & Producing					
Perforations:	812 to 816 ft (Repeat)			Total Perf's:	4	ft
Fluid Type:	Fresh Water		Fluid Gradient:		0.433	psi/ft
Hydrostatic:	352	psi	Fracture Gradient:		1.17	psi/ft
Maximum STP:	[Frac Gradient – Fluid Gradient] x Mid Perf Depth:				600	psi

Test Data

Time of Day (24 hr) (hh:mm)	Δt (min)	Tank Fluid Level (inches)	Injection Rate (gpm)	Injection Pressure (psi)	Comments
08:23	0	38 1/8		518	Start injection
08:38	15	37 3/16 13.88 gals	0.93	531	
08:53	30	36 11/16 21.29 gals	0.49	537	
09:08	45	36 7/16 29.62 gals	0.25	523	Pressure increased
09:23	60	36 1/8 29.62 gals	0.31	567	
09:53	90	35 9/16 37.95 gals	0.28	563	
10:23	120	35 1/16 45.36 gals	0.25	569	
10:53	150	34 9/16 52.77 gals	0.25	574	
11:23	180	34 1/8 59.25 gals	0.22	579	
11:53	210	33 3/4 64.80 gals	0.19	584	
12:23	240	33 1/4 72.21 gals	0.25	585	Conclude injection
Test Totals		72 gals			
Average			0.30 gpm	557 psi	

06:45 On site rigging up
08:23 Began injection test, no break down noted
12:23 Well head needle valve closed.
BHP pressure gauges at 779 ft

Pinnacle on-site supervisor: Brian Laging