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Production history matching to determine reservoir properties of important coal groups in the Upper Pottsville formation, Brookwood and Oak Grove fields, Black Warrior Basin, Alabama

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Abstract

The Black Warrior Basin of Alabama is one of the most important coal mining and coalbed methane production areas in the United States. Methane control efforts through degasification that started almost 25 years ago for the sole purpose of ensuring mining safety resulted in more than 5000 coalbed methane wells distributed within various fields throughout the basin. The wells are completed mostly in the Pratt, Mary Lee, and Black Creek coal groups of the Upper Pottsville formation and present a unique opportunity to understand methane reservoir properties of these coals and to improve their degasification performances.

The Brookwood and Oak Grove fields in the Black Warrior Basin are probably two of the most important fields in the basin due to current longwall coal mining activities. In this work, methane and water productions of 92 vertical wellbores drilled, some completed 20 years ago, over a current large coal mine district located in these two fields, were analyzed by history matching techniques. The boreholes were completed at the Mary Lee coal group, or at combinations of the Pratt, Mary Lee, and Black Creek groups. History matching models were prepared and performed according to properties of each coal group.

Decline curve analyses showed that effective exponential decline rates of the wells were between 2% and 25% per year. Results of production history matching showed, although they varied by coal group, that pressure decreased as much as 80% to nearly 25 psi in some areas and resulted in corresponding decreases in methane content. Water saturation in coals decreased from 100% to between 20 and 80%, improving gas relative permeabilities to as much as 0.8. As a result of primary depletion, permeability of coal seams increased between 10 and 40% compared to their original permeability, which varied between 1 and 10 md depending on depth and coal seam. These results not only can be used for diagnostic and interpretation purposes, but can be used as parameter distributions in probabilistic simulations, as illustrated in the last section of this paper. They can also be used in conjunction with spatial modeling and geological considerations to calculate potential methane emissions in operating mines.

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Appendix A. Supplementary material

Supplementary material related to this article can be found at http://dx.doi.org/10.1016/j.jngse.2012.10.005.

Keywords

History matching; Black Warrior basin; Mary Lee coal group; Upper Pottsville formation; Coal reservoir properties

1. Introduction

1.1. Significance and objective

Ventilation of underground coal mines with adequate amounts of air is important to prevent formation of explosive methane-air mixtures during mining operations. However, when gas contents of coal seams are high, or their structural and reservoir properties favor high methane emissions, ventilation alone may not be enough to keep methane levels within statutory limits, increasing the potential for methane ignitions and explosions. At this juncture, using vertical or horizontal degasification wells prior to mining is an effective way to supplement ventilation to control methane emissions during mining and improve worker safety (Diamond, 1994; Karacan et al., 2007, 2011; Moore, 2012).

Regardless of whether methane emissions can be controlled by ventilation alone or by any pre-mining degasification methods, fluid-flow-related and fluid-storage-related reservoir properties of the coal seam must be known. Coal seam pressure, permeability, relative permeability, gas content, isotherms, and water saturation are most important. These properties of the mined seam are not only important for estimating methane emissions into the ventilation system but are also critical for the success of degasification operations prior to mining. The importance of sorption, permeability, multiple influencing factors, and relative permeability in coal seams are discussed in detail in various publications (e.g. Saulsberry et al., 1996; Karacan, 2008; Busch and Gensterblum, 2011; Liu et al., 2011; Clarkson et al., 2011). In addition, the effects of various mining and coal reservoir properties on potential emissions into mine workings during development mining of coal seams are discussed in Karacan (2008) using dynamic reservoir simulation.

If there are no producing wells in the field, proven techniques to determine coal reservoir properties include laboratory analyses (Gash, 1991; Saulsberry et al., 1996), geophysical logs (Li et al., 2011), and well testing methods (Aminian and Ameri, 2009; Nie et al., 2012). The major problem is, however, that it is not easy to determine reservoir properties of coal seams and they may be quite variable within the coal seam, even within relatively short distances. In addition, each of these methods has advantages and disadvantages. For example, laboratory analyses may not reproduce in-situ conditions, whereas well testing techniques, although dependable, can be complicated, expensive, and sometimes require lengthy times to gather and process the information. If there are existing wells which have produced or have been producing for sufficiently long times, their production information can be analyzed by decline curve and in history matching methods to determine reservoir properties of coal seams.

In this paper, methane and water production of 92 vertical wellbores drilled in the Brookwood and Oak Grove fields of the Black Warrior Basin were analyzed by history matching techniques. The study area shown in Fig. 1 is approximately 12,900 acres and is located on the border of Tuscaloosa and Jefferson counties. The coal mine located within the study area has recently begun operation in the Mary Lee coal group to primarily extract the Blue Creek seam by longwall method. The goal of this work is to determine reservoir properties of Pratt, Mary Lee, and Black Creek coal groups separately, so the results can be used in probabilistic simulations of methane production to estimate potential methane emissions and better plan degasification drilling in advance of mining to reduce methane levels to safe, manageable levels.

1.2. A brief description of the Black Warrior basin and Upper Pottsville formation in relation to this study

The Black Warrior basin is one of the most important coal mining and coalbed methane production basins in the Alabama thrust belt and in the US. The basin has a complicated and yet interesting sedimentary and structural geology that affects coal mining and gas production. However, for the purpose of this paper, only a brief description of the basin and the Pottsville formation that is most relevant to the current study and presented data will be given.

The original intent of coalbed methane production, which still is one of the prime objectives, was to decrease gas content of the coal seams to ensure safe mining. The first attempt to degasify coal seams in the Black Warrior Basin started in 1971, in the Oak Grove field in Jefferson County, with a 5-hole pattern drilled in the Mary Lee coal to reduce the emissions of a then-operated mine. The results of this test showed that methane production using vertical boreholes combined with hydraulic fracturing significantly decreased frictional ignitions and methane explosion danger in the coal mine (Elder and Deul, 1974). After this test, drilling vertical boreholes and fracture stimulation became a standard practice in the area for mining safety and concurrent economic gas production. The wells completed in 5–20 coal seams in various coal groups (Pashin et al., 2010a) ensured safe mining and provided economic gas production. They also provided unique information about the impacts of major stratigraphic, structural, and hydrogeological effects on coalbed methane well performance.

The majority of the coal-bearing strata of economic value in the Black Warrior Basin are in the Pennsylvanian age Pottsville formation. Coal bed gas is generally produced from the Upper Pottsville formation shallower than 3000 ft (Pashin and Groshong, 1998). The Upper Pottsville formation contains Brookwood, Utley, Gwin, Cobb, Pratt, Mary Lee, and Black Creek coal groups. Among these coal groups, Pratt, Mary Lee, and Black Creek coal groups are the most important due to ongoing coal mining and coal gas production activities (Fig. 2). These coal groups were studied in this paper to determine their reservoir properties using history matching.

Pratt, Mary Lee, and Black Creek groups include individual seams of varying thickness within the study area. The Pratt group contains the Pratt, Curry, and Gillespy seams, the Mary Lee group contains the New Castle, Mary Lee, Blue Creek, and Jagger seams, and the Black Creek group contains the upper and lower Black Creek seams (Fig. 2). The rank, or maturity, of these coals ranges from high volatile A to low volatile depending on depth.

The southeast margin of the Black Warrior basin is upturned by strata folding into local anticlines and synclines, namely the Blue Creek anticline and syncline (Fig. 1). These two local folds bring the coal seams to the surface, where the reservoir pressure is relieved and where the coal seams can accept meteoric waters. Structural deformation in the general area has significant effect on the performance of coalbed methane reservoirs, the hydrodynamics in the area, and on the pressure gradients within the coal reservoirs with varying distance to these deformations (Pashin, 2007; Groshong et al., 2009; Pashin, 2010). The particular study area of this paper is approximately 5 miles from the main thrust fault and from the Blue Creek anticline and syncline (Fig. 1). Therefore, neither of the coal groups that are investigated in this paper outcrop within the study area. The average depths, which were determined from perforation intervals of the studied boreholes and from their logs, are between 600 and 1200 ft for the Pratt coal group, between 1200 and 1950 ft for the Mary Lee coal group, and between 1950 and 2500 ft for the Black Creek coal group (Fig. 2). The relative frequency histograms of the completion intervals of each of the coal groups are given in Fig. 3.

Due to the distance to the Blue Creek anticline-syncline and mining activities that started long before the start of coalbed methane activities, the study area is moderately under-pressurized. The average hydrostatic gradient within and around the study area is 0–0.3 psi/ft (Pashin, 2007).

The coal groups in the Upper Pottsville formation effectively have no matrix permeability. Thus, flow within the Pottsville coal groups takes place through cleats and fractures and makes coal seams in this formation the best aquifers of all existing rock types within the interval. Unless there is a disturbance, such as gas production or mining, coal seams can be assumed to be 100% water saturated.

The permeability of Warrior basin coals is highly sensitive to stress, with permeability decreasing with depth from ~100 md at the surface to 1–2 md below 2000 feet (McKee et al., 1988). As with permeability, porosity of coals in the Pottsville formation varies with depth as well. The porosity of the coal can be as high as 5% at the surface and can decrease substantially with depth as a function of overburden stress and the coal’s mechanical properties. Pashin et al. (2004, 2008) and Pashin (2012, personal communication) suggest that porosity is less than 3.0 percent in the Pratt coal group, which is the shallowest of the three coal groups studied in the paper and also the shallowest target for coalbed methane development in the area. On the other hand, they suggest that porosity in the Mary Lee coal group ranges from 1.5 to 1.8 percent, with porosity around 1.0 percent in the Black Creek coal group, which is the deepest coal group of interest.

2. Vertical coalbed methane wells of the study area and their overall production history

2.1. Production durations and decline rates

The 12,900-acre study area with coalbed methane well locations is shown in Fig. 4. The first of the wells was drilled in 1987 in the Oak Grove field and was completed only in the Mary Lee coal group. In later years, other wells were drilled and completed in one or more of the three target coal groups, as shown in Fig. 4. By the year 1998, virtually all of the 92 wells in this area were drilled, perforated, and fractured to put them into production.

Production histories of vertical methane wells in the Black Warrior basin are affected by water and gas saturation in the coal seams as well as well completion efficiencies and local geology (Pashin, 2007). Scheduling of mining operations also affects production histories of the wells as they are progressively terminated before coal mining commences. These factors may also affect production duration of the wellbores. The production duration overlay image in Fig. 4 spatially shows that the majority of the wells have more than 7500 production days. These wells were completed at multiple zones, mainly in Mary Lee and Black Creek coal groups (Fig. 4). Wells at the northeast corner of the study area produced for 4000 days or less. These wells were completed only in the Mary Lee coal zone and were terminated when the Oak Grove mine was developed in this location in 1993–1994. Wells that were placed on the western margin of the study area, in the Brookwood field, were drilled in 1997 and were completed at all three coal groups. They have been in production since their start date, for about 6000 days. Fig. 5 shows a 3-dimensional reservoir view of the three coal groups studied in this work. This figure shows the variation of depth from surface to these coal groups, locations of well completions in each of the coal groups, as well as the locations and displacements of faults shown in Fig. 4. In addition, the Mary Lee coal group image in Fig. 5 marks the boundaries of the mine panels and how they relate to well locations and proximities to faults.

Production start dates of all wells and their production durations, as of the date of the last recorded data at the time of preparation of this work, are given in Fig. 6. Despite the fact that all producing wells in this area are currently in their decline periods, Figs. 4 and 6 show that almost all wells have been extremely long producers. Variations in production durations can be due to mining operations, well completion properties (i.e. whether the wells are completed at a single zone or at multiple zones), coal reservoir properties, and proximities to faults (Fig. 5). Sparks et al. (1993) observed that fault lines in many areas in the basin may not be as productive as blocks between the faults—supported by Pitman et al. (2003) who observed that cementation of coal cleats within ~30 ft of normal faults could preclude flow along large parts of faults.

To further investigate production and decline behaviors of wells in the study area, decline curve analyses were performed. The analyses showed that almost all wells exhibit exponential decline, which by definition is constant with production duration. An example of exponential decline curve analysis on production data plotted as the logarithm of gas rate versus time is given as the inset of Fig. 7. It should be noted, however, that traditional decline analyses apply only to the long-term decline periods where boundary-dominated flow is dominant. Therefore, as also seen in this inset figure, initial and intermittent short-lived declines due to various operational factors and rate transients were not included in this analysis.

The decline rate data given in Fig. 7 has a minimum of 1.8% per year and maximum of 25% per year. The mean and standard deviation of the distribution is 9.2% per year and 6.3% per year, respectively. Interestingly, the distribution shows a multi-modal behavior, in which low, medium, and high decline rates are clearly distinguishable and the wells creating these populations of data approximately coincide with the wells grouped in Fig. 4 based on their completion zones.

2.2. Production rates and cumulative productions

Pashin (2007) and Groshong et al. (2009) discussed that folds and faults in the Black Warrior Basin and close to its margins can have significant impact on peak production rates and production durations of coalbed methane wells. Folding of the strata is believed to increase methane rates locally as a result of increased fracture permeability. Such areas of increased methane rates, or peak rates of as much as 150–300 Mscf/day, are generally observed along the lower limb of the Coalburg syncline in the Cedar Cove field (Pashin et al., 2010a). Peak rates of water production as much as 250–750 bbl/day, on the other hand, were observed close to the Blue Creek syncline and anticline where the strata upturned and were exposed to the surface, accepting meteoric water encroachment.

The study area is not directly located on or at very close proximity to one of the major structures in the Appalachian front. However, tectonic maps prepared from various borehole logs and seismic reflection profiles indicate that the Pottsville formation in the southwestern edge of the Oak Grove field and in a majority of the Brookwood field have normal faults (Groshong et al., 2009). The major faults of the study area are also shown in Fig. 4 and more clearly with variations in depths in Fig. 5. Thus, impact of normal faults dissecting the Upper Pottsville formation may be present in gas and water production rates, as well as cumulative productions, of wellbores of the study area.

Methane and water rate histograms using 20,100 recorded rate data from all wells and the cumulative production histograms of 92 wells are shown in Fig. 8A–D. The histogram in Fig. 8A shows that the methane production rate was generally lower than 200 Mscf/day with a mean of 58 Mscf/day and standard deviation of 42 Mscf/day. The maximum recorded rate from the wellbores in this area was 706 Mscf/day. However, this extreme rate was instantaneous and should not be considered a peak. Water production data shown in Fig. 8B, on the other hand, shows that the majority of recorded rates were lower than 100 bbl/day, with a mean value of 47 bbl/day and a standard deviation of 99 bbl/day. The highest water production rate recorded from the wells in the study area was 1384 bbl/day.

Histograms of cumulative production are shown in Fig. 8C and D for methane and water, respectively. Cumulative methane production distribution shows a multi-modal behavior, where the minimum cumulative methane production was 28 MMscf and the maximum was 1100 MMscf. The mean and standard deviation of cumulative methane production was 362 MMscf and 256 MMscf, respectively. Cumulative water production is similar to water rates in distribution, having a mean of 268,000 bbl and standard deviation of 443 bbl.

In general, all wells in the study area have been exceptional producers. The production durations, decline rates, as well as production rates and volumes may have been affected by the geological structure of the basin, or more specifically by the structural features of the study area. However, they may also have been strongly impacted by the near-wellbore effects of well stimulations (such as hydraulic fracturing) and by reservoir properties of the coal groups in the study area, which were not exclusively studied in the literature. In addition, and probably more importantly from a mining safety point of view, coal reservoir properties and their change over time dictate potential amount and rate of methane emissions into working areas and active and sealed longwall gobs. Therefore, it is critical to determine coal reservoir properties and their distributions in a mining and gas production site.

In the following sections, the properties of Pratt, Mary Lee, and Black Creek coal groups will be investigated. The production history matching technique will be implemented to delineate reservoir properties and their time-dependent changes.

3. Production history matching

3.1. Preliminary preparation of data for auxiliary functions and history matching

The objective of history matching is to find an optimum solution to the theoretical model-field data problem to determine unknown reservoir parameters. Ideally, performing history matching of all wells at the same time using reservoir simulation is preferred to better capture interferences. However, the reservoir simulation method can be computationally expensive and time consuming for matching tens of wells at the same time. This is particularly the case if reservoir properties show spatial variations, which is usually the case in coal seams. In this case, reservoir simulation becomes a tedious and lengthy task for matching the production behavior of all wells by changing relevant reservoir properties. Single-well history matching practice by using analytical or numerical models for each well independently, on the other hand, can be employed in lieu of large-scale reservoir simulations to estimate the reservoir properties in a relatively shorter timeframe. The results can later be used in forecast mode to predict future production behavior of the well, if needed.

In this study, history matching computations and analyses were completed using Fekete's F.A.S.T. CBM™ software version 4.7 (Fekete Associates, Inc., 2012) independently for each well. Although single-well history matching is easier than full-scale reservoir simulation, it is not straight forward either. Using F.A.S.T CBM™ for this purpose is no exception. Following sections give details of preparing well data, pressures, deliverability data, sorption properties of each coal seam and porosity-permeability-sorption relationships and associated considerations. The first step of history matching, of course, is learn about the geology of the area and general reservoir conditions. Gathering any seismic and well log data immensely help in understanding the reservoir and low/pressure behaviors. Next, it is essential to evaluate the production data and production pressures. It is important to recognize the data trends and to be able to explain the changes with the help of Supplementary Information, such as any workover or stimulations, or general characteristics of the reservoir. In some cases where the data is erratic, data filtering may help for making the actual behaviors clear. It is also important to analyze the reported completion intervals and to decide whether all completions are producing from the same horizon. This will help deciding whether the well and the layers in the model should be planned as a single unit or as multi-layer.

Decline curve analysis as the first step of modeling is helpful, as it is easy to conduct and it provides information on decline trends, coefficients related to reservoir and flow mechanics. It also helps and gives an idea about reservoir extends, future production potential in terms of expected ultimate recovery, gas-in-place, and in the case of using type-curves, it gives a preliminary idea about permeability.

History matching phase includes importing the final data set into the simulator with appropriate units. Defining wellbore geometry and wellbore hydraulics follow. These data are usually available in well drilling and production records as well as in well log reports. Next, parameters of reservoir volumetrics are defined. These include defining sorption functions, coal density and the basis of these measurements. It is important to pay attention to conduct the volumetric calculations with the correct basis that the data come from. For instance, it should be paid attention whether the measurements were on as received basis or dry-ash free basis, as these will affect volumetric gas-in-place.

It is also important to know, to the best of the knowledge, whether the reservoir is a dry coal or wet coal reservoir. This means that if there is water flowing along with gas, this should be known as some of the numerical models cannot be used in the case of wet coals. So, this consideration help selecting an appropriate model that will reflect the actual flow processes, and boundary conditions. Upon completion of relative permeability, matrix shrinkage and other reservoir related properties, such as near-wellbore conditions, history match can be conducted either manually or automatically, during which some of the reservoir parameters are adjusted for matching water and gas productions, or the pressures. It is important also to note that relativity permeability and porosity can further be used to adjust the shape of production curves to obtain a successful match.

Uniqueness of results is important in history matching. Therefore, results should be checked to see whether they make sense when compared with near-by wells or with the data in literature. Further, it is important to obtain the results where the error is at global minimum, rather than at local minimum. It helps to provide the simulator with slightly different parameters than the ones determined and run the simulation again. If the results come back to the same values, then it increases the confidence toward the values. It also should be noted that each well can have a different situation that necessitates selecting a different model or boundary conditions. Therefore, each well should be treated individually and by paying attention to the details while preparing the simulations.

Above paragraphs give general aspects of the workflow followed in this study. Detailed discussion of production data analyses and workflow for unconventional reservoirs is given in Clarkson (submitted for publication-a,submitted for publication-b).

Following sections give the details of estimation of input parameters in this study.

3.1.1. Production model for history matching and layer definitions—For modeling, pseudo-steady state (PSS) boundary-dominated solutions were used. This is justified by all wellbores within the study area having been productive for a sufficiently long duration as discussed in the previous section. A PSS solution does not capture the initial, and usually short, transient part of the production history that stems from the pressure and desorption changes at the immediate vicinity of the wellbore in the initial production period. However, given the long production times and the nature of the reservoir data being determined, initial transients were deemed not critically important. With these considerations, the following formulas were used in deliverability calculations for gas and water rates, respectively, in history matching:

$$q_g=\frac{k_{eg}h\left[m\left(p\right)-m\left(p_{wf}\right)\right]}{1422T\left[ln\frac{r_e}{r_w}-\frac{3}{4}+s\right]} \quad (1)$$

$$q_{\mathrm{w}}=\frac{k_{\mathrm{ew}}h\left[\bar{P}-P_{wf}\right]}{141.2\mu_{\mathrm{w}}B_{\mathrm{w}}\left[ln\frac{r_{\mathrm{e}}}{r_{\mathrm{w}}}-\frac{3}{4}+s\right]} \quad (2)$$

In these equations, h is net pay, which was calculated from the total thicknesses of coal seams in a coal group, k_{eg} is gas effective permeability, $m(P)$ is gas pseudo-pressure, $\bar{P}$ is average reservoir pressure, P_{wf} is flowing bottom hole pressure, T is temperature, r_e is external radius, r_w is wellbore radius, μ_w B_w are water viscosity and water formation volume factor, respectively, and s is the near-wellbore skin due to stimulation. Since all wellbores were hydraulically fractured, s was retained in equations from which fracture half-length could be calculated using:

$$s=-ln\left(\frac{\alpha X_{\mathrm{f}}}{r_{\mathrm{w}}}\right) \quad (3)$$

where X_f is the fracture half-length and α is a function of the fracture's dimensionless conductivity (F_{CD}).

The study area has 92 wells with varying completion intervals (Figs. 4 and 5). All of these wells are completed in the Mary Lee coal group, with 20 and 45 of these wells also being completed in the Pratt and Black Creek groups, respectively. Thus, from a modeling point of view, if a well is completed only at the Mary Lee group, a single-layer completion approach was used. However, if a well is completed in more than one interval, then a multi-layer approach was used as the total production had contributions from each layer. In the latter approach, known parameters of each layer were assigned separately to corresponding layers according to their properties.

3.1.2. Flowing pressures—The Alabama Oil and Gas Board collects water and gas production data, but it does not monitor wellhead flowing pressures. Pashin (2012) indicated that wellhead pressure is gauged routinely by operators, and most wells are operated at a surface flowing pressure of 8–12 psig. Thus, surface flowing pressures of all wells were taken as constant at 10 psig during their entire production period. Bottom hole flowing pressures were estimated using well depth and by assuming pressure loss due to friction to be zero. Additionally, all wellbores were assumed to have an internal diameter of 6 inches for each completion interval over the entire borehole length.

3.1.3. Adsorption isotherms, initial pressures, and gas contents—In coalbed methane fields, the majority of gas is produced from initially adsorbed gas quantity, which is a function of pressure and is defined by the Langmuir isotherm of the coal seam. Langmuir isotherm defines the relationship between pressure and gas content of coal according to the formula:

$$V(P)=\frac{V_{\mathrm{L}}P}{P_{\mathrm{L}}+P} \quad (4)$$

In this equation, P is pressure, $V(P)$ is the amount of gas at P, also known as the gas content, V_{L} is Langmuir volume parameter, and P_{L} is Langmuir pressure. Gas content data is also used in calculating gas-in-place for material balance calculations.

Langmuir parameters are coal-specific. Thus, they should be determined at representative temperatures of the coal seams. The isotherms used in this study were determined at 86 °F using samples from the coal seams of interest, and Langmuir values were determined and used in the models based on an "as received" basis reflecting the presence of moisture and ash in the data.

Langmuir isotherms used in this study were obtained from measurements conducted at different seams included in each of the coal groups. In order to determine representative Langmuir parameters for the Mary Lee coal group, experimental data obtained separately from the New Castle, Mary Lee, Blue Creek, and Jagger seams (Fig. 2) were used. A single Langmuir isotherm was fitted to represent all coal within the interval. The same procedure was applied for Pratt and Black Creek Coal groups. The results are given in Fig. 9.

Estimation of the study area pressure gradient and Langmuir parameters of coal groups makes it possible to determine initial pressure of the coal reservoir and its gas content. Pashin (2007) reported that the average hydrostatic gradient within and around the study area was between 0 and 0.3 psi/ft. As an average value, 0.15 psi/ft gradient was used to calculate initial pressures at mid-depths of each of the coal groups and their initial gas contents.

All wells in the study area simultaneously started their production with gas and water without any indication of under-saturation. Thus, coals were assumed to be saturated and initial pressure of each coal group was taken as equal to their desorption pressure.

3.1.4. Permeability increase as a result of matrix shrinkage during depletion—Permeability increases as a result of reservoir pressure depletion during methane production have been observed in various coalbed methane basins (e.g. San Juan Basin). Several mechanistic and geomechanical models have been proposed to model this phenomenon. A critical review of these models with field and experimental data reflecting those circumstances for which these models can be used is given in Pan and Connell (2012). Recently, Mazumder et al. (2012) applied some of these models to permeability increase in the Bowen basin coals as a result of primary depletion. They observed that absolute permeability increased by several magnitudes as a function of estimated reservoir pressure.

The Shi and Durucan model (2003), which is shown in Eqs. (5) and (6), was used to model matrix shrinkage and permeability increase as a result of methane production from wells.

$$k = k_o e^{-3c_\varnothing}(\sigma - \sigma_o) \quad (5)$$

In Eq. (5), k is the permeability at effective stress (σ) at coal reservoir pressure (P), k_o is the initial permeability at initial effective stress (σ_o) at initial reservoir pressure (P_o). As mentioned in the previous discussion, coals were assumed to be saturated, and calculated initial reservoir pressure was equal to desorption pressure. This means that the pressure-gas content cross point is on the isotherm and changes following the isotherm function. With these conclusions, Eq. (6) can be used since reservoir pressure will be under desorption pressure after production starts. Thus, the desorption-induced stress change in coals is:

$$\sigma - \sigma_o = -\frac{\gamma}{1-\gamma_o}(P - P_d) + \frac{E}{3-3\gamma}\varepsilon_L\left(\frac{P}{P+P_d} - \frac{P_d}{P_d+P_\varepsilon}\right) + \frac{\gamma}{1-\gamma}(P_c - Po) \quad (6)$$

The terms of Eq. (6) are γ – Poisson's ratio, P_d – desorption pressure, P_ε – the pressure at 50% of maximum matrix strain, E – Young's modulus, and ε_L – maximum strain. Unfortunately, there was no separate data available for Pratt, Mary Lee, and Black Creek groups. Thus, geo-mechanical parameters were selected for coal strain as a result of methane desorption based on reported data in literature (Fekete Associates, Inc., 2012; Robertson, 2005). Fig. 10 shows the shape of permeability change functions for coal groups and the parameters used in this study.

3.1.5. Permeability anisotropy—Interference testing studies indicate that anisotropy is best developed in the shallow, low-stress seams of the Pratt coal zone, and is typically greater than 15:1 (Pashin et al., 2010b). In the pre-fracture tests performed in Oak Grove field, the flow in the face cleat direction was favored. On the other hand, no permeability anisotropy was observed in the Mary Lee coal zone of the Oak Grove field. Observations at the Oak Grove mine, near the study area, indicate that the coals in this zone are sheared as a result of bedding-plane slip driven by Appalachian folding (Pashin, 2012). Some thin detachments within the Blue Creek seam in Brookwood field are observed. However, the coal is largely cleated and may exhibit cleat and hydraulic fracture-dominated anisotropy locally. The Black Creek seams of the Black Creek coal group exhibit weak anisotropy in the systematic joint direction in the Oak Grove field and may have anisotropy in the face cleat direction in the Brookwood field.

Because of a lack of a generally known trend and the ratio of natural permeability anisotropy in the coal groups within the study area, and because permeability anisotropy around the wells is generally dictated by the direction of hydraulic fractures created, no specific anisotropy ratio was used in history matching. For the Pratt, Mary Lee, and Black Creek groups, the direction of estimated fracture half-lengths should correspond to the general direction of fracture growth observed in previous studies (Gazonas et al., 1988; Steidl, 1993). This will be discussed later in the history matching results.

3.1.6. Relative permeability functions—Relative permeability of coal seams is not only important for deliverability of gas and water, but also for determination of gas and water production characteristics. Clarkson et al. (2011) discuss the importance of relative permeability curves for coal seam gas production.

Relative permeabilities are a function of saturation of corresponding phases in multi-phase flow in porous media. Field evidence and production characteristics of the wells suggest that cleats were initially 100% saturated with water at the start of well production. Thus, initial water saturation was taken as 100%.

Corey relative permeability functions given in Eqs. (7) and (8) were used for gas and water, respectively.

$$\frac{krg}{krgo}=\left(\frac{\bar{S}_{\mathrm{g}}-S_{gc}}{1-S_{wc}-S_{gc}}\right)^{N_{\mathrm{g}}}, \quad \bar{S}_{\mathrm{g}}\geq S_{gc} \quad (7)$$

$$\frac{k_{rw}}{k_{rwo}}=\left(\frac{\bar{S}_{\mathrm{w}}-S_{wc}}{1-S_{wc}}\right)^{N_{\mathrm{w}}}, \bar{S}_{\mathrm{g}}\geq(1-S_{wc}) \quad (8)$$

where k_{rg} is the relative permeability to gas, k_{rgo} is the end-point relative permeability to gas, k_{rw} is the relative permeability to water, k_{rwo} is the end-point relative permeability to water, N_w is the exponent of the water relative permeability curve, N_g is the exponent of the gas relative permeability curve, $\bar{S}_g$ is the average gas saturation, $\bar{S}_w$ is the average water saturation, S_{gc} is the irreducible gas saturation and S_{wc} is the irreducible water saturation.

In the absence of experimental data suggesting otherwise, gas and water end-point relative permeabilities were kept at 1. Owing to the long production durations of the wells with high gas and water rates, irreducible saturations of the phases were assigned low values—1% and 0.1% for water and gas, respectively. Basically, gas and water relative permeability exponents were the main adjustable parameters of these functions, along with other parameters of deliverability during history matching. It was found that the gas exponent could take values changing between 1 and 2, whereas the water exponent could change between 3 and 12, depending on the shape of production curves and rates. Fig. 11 shows the general shape of the relative permeability curves and the parameters of the Corey model that were used in history matching.

3.1.7. Porosity—Porosity of coal is the fracture porosity and is mostly responsible for the amount of water storage. Thus, porosity was used as a matching parameter primarily for water quantity and flow rate.

Estimated initial porosities were converted to final porosity using the following relation:

$$\frac{k}{k_o}=\left(\frac{\varnothing}{\varnothing_o}\right)^n \quad (9)$$

In this relationship, k_o and k are initial and final permeabilities, respectively, and $\varnothing_o$ and $\varnothing$ are initial and final porosities. The exponent n was set to 3, consistent with typical applications.

4. Production history matching results and their discussion

Well productions were simulated starting from their production start until the date of last collected or reported data for June, 2011. Thus, if a well has operated through 2011 and into 2012, the final value of the changing reservoir and transport properties (e.g. pressure, gas content, permeability, relative permeability, saturations) are reported for June, 2011, and are termed as “existing” in this section to refer to the “current” values in the field. However, if the well stopped production before June of 2011, the final value of the simulation at the production-end date was reported as of June 2011, assuming that the values had not changed.

As discussed earlier, history matching was performed based on the completion properties of each well to determine properties by individual coal groups and completed either as single-layer or multi-layer models. Fig. 12 shows examples of history matching results for wells 5236-C, 5603-C, and 6137-C, completed at the Mary Lee group only (single layer), at the Mary Lee and Black Creek groups (dual layer), and at the Pratt, Mary Lee, and Black Creek coal groups (three layers), respectively.

For each well and coal group, initial and “existing” reservoir properties, as appropriate, were determined using history matching. These include permeability, relative permeability (gas and water), effective permeability (gas and water), water saturation, formation pressure, gas content, skin, and fracture half-length. Minimums, maximums, means, standard deviations as well as quartiles of the distributions of existing values of reservoir and fluid transport properties for each coal group are given in Table 1. The same statistical measures for near-wellbore effects and drainage area are given in Tables 2 and 3, respectively. The following discusses matching results and reservoir parameters for the various coal groups.

4.1. Coal reservoir and fluid transport properties

4.1.1. Pressures and gas contents—Fig. 13 shows the initial and “existing” pressures of the coal groups as of June 2011. Initial pressures were calculated based on an initial pressure gradient of 0.15 psi/ft. Thus, pressures increased with depth and reached to values close to 175 psi, 265 psi, and 355 psi at the depths of the Pratt, Mary Lee, and Black Creek coal groups, respectively. After history matching, existing formation pressures in the coal groups were estimated as low as 25–50 psi at some well locations, which corresponded to the highest producers. The mean pressures estimated from all well locations were 94 psia, 117 psia, and 215 psia with standard deviations of 39, 57, and 72 psia for Pratt, Mary Lee, and Black Creek groups, respectively.

The ultimate objective of any degasification process is decreasing gas content of the coal seams prior to mining. Fig. 14 shows the initial gas contents within coal groups as a function of depth, which were calculated based on initial pressures and the isotherm functions of the coal groups shown in Fig. 9. Initial values show that the highest gas contents between 275 and 360 scf/ton were in the Mary Lee coal group, followed by the Black Creek and Pratt groups. This is particularly important as the Blue Creek and Mary Lee seams are the main mining targets, and the New Castle and Jagger seams (Fig. 2) contribute to methane emissions from roof and floor, respectively. Therefore, it is important to also decrease gas content of this coal group to improve mine safety. Indeed, gas content predictions based on history matching show that gas contents of coals decreased to 50–60 scf/ton in some areas (Fig. 14), corresponding to those locations where existing pressures were lowest. However, distribution of gas content data between initial and existing values suggests that there are remaining locations in all coal groups with very high methane contents. This is particularly important for the Mary Lee coal group as it is a primary mining target. Such high gas content locations should be further degasified using other options prior to mining. The mining company operating here is presently addressing this problem by degasifying the Blue Creek seam using horizontal cross-panel holes. Although this is certainly a benefit, the overlying New Castle and underlying Jagger seams can still contribute to the emissions. Spatial distributions of existing gas contents within the Mary Lee group are shown in Fig. 15.

4.1.2. Permeability and porosity—Permeability and porosity control fluid-flow and fluid-storage capacity in porous formations. Practically, these refer to the properties of coal cleats or fractures since there is no matrix permeability. Permeability of coal seams is not only important for the efficiency of degasification, but also for methane emissions into coal workings during mining.

Initial and existing permeability and porosities of coal groups were determined using history matching of gas and water productions. In history matching, permeability and its evolution controlled both gas and water rates to match the full trend of production. Porosity was estimated to ensure there was adequate water produced and also for matching water production. Permeability change as a result of desorption and stress variation in coal was calculated using the Shi and Durucan model given in Eqs. (5) and (6). A corresponding change in porosity was calculated using Eq. (9). Results are shown in Fig. 16A and B.

Fig. 16A shows in general that Black Creek group has the minimum permeability, ranging between 0.1 and 2 md. Existing permeabilities in this group have a mean of ~1 md. The Mary Lee group, on the other hand, has existing permeabilities that vary between 0.5 and 18 md. The Pratt coal group has higher estimated permeabilities between ~4 and 15 md with a mean of 8.4 md, potentially due to its shallower depth. It is clear from Fig. 14A that the permeability of coals is sensitive to depth, and thus to stress. The statistics of permeability distribution are given in Table 1. Porosities that are given in Fig. 16B show values that generally range between 0.2% and 3%. However, they do not seem to be as sensitive to depth as permeability. Permeabilities and porosities estimated for Pratt, Mary Lee, and Black Creek coal group corroborate well with the findings and measurements reported by McKee et al. (1988) and by Pashin et al. (2004, 2008) and Pashin (2012), who presented similar values for permeability and its sensitivity to depth. They also presented porosity values under 3% as predicted in this study.

History matched values estimated for initial permeability and porosity are slightly lower than the existing values computed during the matching process (Fig. 16A and B), likely due to the matrix shrinkage effects as a result of desorption and pressure decrease. The amount of change in permeability and porosity in each coal group is given in Fig. 17A and B, respectively. These data indicate that existing permeabilities in the Pratt group coals exceed their initial values by 25–30%, whereas this increase is up to 20% in the Black Creek group coals. In the Mary Lee group, the permeability increase is up to 50%. These anomalies in different coal groups are due to the differences in their isotherms and the amount of pressure decrease and gas desorption experienced during production. Porosity has a similar trend and behavior to permeability, compared to initial values. However, calculated porosity increases are less than 15% of the initial values (Fig. 17B).

4.1.3. Relative and effective permeability—Relative permeabilities to gas and water are functions of saturation. As saturations change as a result of depletion, relative permeabilities vary based on the approximated relative permeability function in history matching. In this work, Corey functions were used, as discussed in Section 3.1.6. Values of gas and water curve exponents were adjusted during history matching for each of the wells. Fig. 18A–C shows plots of existing relative permeabilities to gas and water versus existing water saturations in each of the coal groups.

The horizontal axes of Fig. 18A–C show that water saturations, which were 100% at each location when production started, diminished to values that vary at each well location. Existing water saturation in the Pratt coal group varies between 29 and 82%, depending on the well location, placing relative permeabilities to gas between 0.2 and 0.7 (Fig. 18A). Consequently, relative permeabilities to water decreased to 0.01 and 0.26 with a mean value of 0.08. In the Mary Lee group, existing water saturation changed between 17 and 88% within the study area. Relative gas permeabilities within this coal group range between 0.07 and 0.82 (Fig. 18B). In the Black Creek coal group, existing water saturations are higher than those of the Pratt and Mary Lee groups. Existing water saturations in the Black Creek groups are between 40 and 95%, indicating there are locations with high water saturation which should be dewatered for more effective degasification. Area-wide gas relative permeabilities in Black Creek coals are between 0.05 and 0.65.

Effective permeabilities to each flowing phase in coals are as important as the relative permeabilities, as they are absolute measures of permeability to a specific phase at a given saturation. Existing effective permeabilities are calculated by multiplying the existing absolute permeabilities given in Fig. 16A for each coal group by the relative permeabilities in Fig. 18A–C. Thus, effective permeabilities prevail at the same saturation conditions. Existing effective permeabilities in each coal group and wellbore location are shown in Fig. 18D–F, for Pratt, Mary Lee, and Black Creek coal groups, respectively. These figures show that effective permeabilities to gas vary between 0.4 and 6.4 md, between 0.15 and 11.1 md, and between 0.02 and 0.9 md in various well locations, in Pratt, Mary Lee, and Black Creek groups, respectively. These values indicate the current water saturation state of these coals and that the effective permeability of gas in the Black Creek coals is very low.

Basic statistics and quartile values of existing coal reservoir and fluid-transport-related parameters presented so far are given in Table 1. These data are intended for understanding the existing values of different properties in these coal groups. More importantly, they can help researchers to construct parameter distributions for probabilistic simulations for forecasting future degasification efficiencies of the wells and related reductions in mine emissions for ventilation and mining safety applications.

4.2. Near-wellbore effects and drainage area

All wellbores in the study area were hydraulically fractured at each completion interval. Therefore, wellbore skins due to fracturing, given in Eqs. (1) and (2), were calculated during history matching for each applicable coal group. Skin due to fracturing is a negative number. Skin values computed during the matching process were later converted to fracture half-lengths in these zones (Eq. (3)). These values are given in Table 2.

Table 2 shows that values of skin in each of the coal zones range between −0.1 and −7.7. Mean skin values for coal zones are around −4.2. Although both skin values and the differences between coal zones are small numbers, they may translate to large fracture half-lengths through Eq. (3) and through their relation with dimensionless fracture conductivity. Indeed, fracture half-lengths calculated at different well locations indicate that total fracture lengths can be as long as 1100–1200 ft. Calculated median values for total lengths are within 48–89 ft, and 75% quartile values are between 320 ft and 430 ft. Fig. 19 shows the spatial distribution of fracture half-lengths calculated at different well locations in the Mary Lee coal group.

Hydraulic fractures in the Black Warrior coals generally dictate the directional permeability anisotropy. Therefore, the directions of estimated fracture half-lengths should correspond to the general directions of fracture growth observed in previous studies for the Pratt, Mary Lee, and Black Creek groups. Steidl (1993) indicated that hydraulic fractures had 70° to 80° azimuths in Black Warrior coals. Gazonas et al. (1988) conducted hydraulic fracturing tests in these coal groups and interpreted tiltmeter and geophysical data to estimate dip, direction, and growth of fractures around the bore-holes. In shallow zones, they have observed both vertical and horizontal fractures. In deep intervals, they have observed a vertical fractures strike of N 78° E in the Mary Lee group and a N 93° E strike in the Black Creek group, with oblique orientations to face (N 61° E) and butt cleats. They have also calculated the length of the vertical fractures as 319 ± 269 ft in the Mary Lee group and 598 ± 245 ft in the Black Creek groups, respectively. Calculated widths of these fractures were 0.07 ± 0.025 ft. With this information, the directions of fractures reported in Fig. 19 can be approximated as N 78° E. Furthermore, it is interesting to note that the reported fracture lengths in Gazonas et al. (1988) are of the same order of magnitude of the values calculated in this study.

Drainage areas of each well for the coal group that they were completed in were also predicted during history matching. Drainage areas established in each coal group are functions of cumulative gas production, net pay thickness, porosity and gas amount stored in the coal. Predicted drainage areas are given in Table 3. These values show minimum areas 6–24 acres and maximum areas between 117 and 173 acres, depending on the coal group and the well location; smaller areas were affected by wells that did not produce for a long time.

5. An example with the use of results

It is very rare to know the exact value of each of the coal reservoir properties. The values, either measured at the laboratory or determined by well testing, can change drastically within a certain range in the field. The uncertainties associated with the values of different reservoir properties can result in over- or under-estimation of production potentials. This can ultimately affect field management for gas production and for gas control for mining safety purposes.

As mentioned earlier in this paper, the possible values of coal reservoir properties determined using history matching of productions from a large number of wells drilled and completed at various coal zones can serve for understanding the effects of various coal parameters in planning degasification wells in this field, their range of values and for conducting probabilistic simulations of well productivity. This section presents an example of using the data given in this paper as tables for probabilistic simulation.

The simulation was conducted using the Monte Carlo module in F.A.S.T CBM™. This module basically solves deliverability equations with a stochastic approach. For this example, the calculations were performed for the well at 5236-C location and for production from Mary Lee coal group. For the sake of this illustration, some of the properties were kept at constant values, while others were varied according to the results given in Tables 1–3. The data given in these tables enable to fit exact distributions (using quartiles), or to use uniform (by using minimum and maximum only), or to use an arbitrary distribution (by just using mean and standard deviation) that the researcher thinks most likely. In order not to create any bias for these options, no distribution was reported as *a priori*. However, for the example, the set of values given in Table 4 were used. The computations were performed using 1000 simulations. The results, in terms of cumulative gas and water production and rates, and with their associated probabilities (for 10, 50 and 90 percentiles) are given in Figs. 20 and 21.

Fig. 20 shows cumulative histogram built by using the results of cumulative gas and water productions from 1000 simulations. The values of gas and water productions that correspond to 10, 50 and 90 percentiles are given as an inset table in this figure. The data shows that at the most favorable cases (P90) interms of input parameters provided, gas and water productions can be as high as 527.5 MMscf and 137,100 bbl, respectively. When the input parameters are not favorable (P10), the productions are as low as 9.8 MMscf and 6900 bbl. The median values (P50) are 190.7 MMscf and 52,500 bbl for gas and water, respectively. Rates are, of course, as important as the cumulative productions. Fig. 21 shows expected gas and water production rates at P10, P50 and P90 probabilities. As a note of interest, the predicted rates are very similar to what's given for 5236-C in Fig. 12. In addition, the presented values in Fig. 20 and the entire range of values in the histogram compare well with the actual cumulative production values given in Fig. 8C and D. Both of these observations provide additional support to the results beyond literature data and suggest that the reservoir properties estimated using history matching is close to actual values.

6. Summary and conclusions

This study conducted production data analyses, decline curve analyses, and production history matching on 92 vertical coalbed methane wells drilled in a 12,900-acre area in Brookwood and Oak Grove fields. A large-scale longwall mining operation has recently commenced in this area, and will operate in the next few years to mine Blue Creek coal of the Mary Lee coal group. Therefore, understanding coal reservoir properties and their existing values is of prime importance to effectively degasify coal seams and to ensure safe mining. A brief description of Black Warrior basin and the Upper Pottsville formation where major coal groups are located is given in the first section of the paper.

The first vertical well in the study area was drilled in the 1980s and the last in 1998. The wells in the study area have been exceptional producers. Decline curve analyses showed that effective exponential decline rates of the wells were between 2 and 25% per year, except for a few wells completed only at the Mary Lee group, which have been producing with low constant percentage decline rates. Productivity of wells with produced volumes of gas and water and their rates are discussed in Section 2.

The main objective of this work was to evaluate coal reservoir properties of Pratt, Mary Lee, and Black Creek coal groups. For this purpose, history matching analyses were performed using pseudo-steady state, boundary-dominated flow solution. Since wellbores were completed at single or multiple coal zones, analyses were conducted to reflect these completion characteristics.

Results of history matching were compiled to reflect the initial and existing conditions in the coal groups. Analyses showed that pressure decreased as much as 80% to nearly 25 psi in some areas and resulted in corresponding decreases in methane content. The lowest gas content calculated for existing conditions in coal groups was 50–60 scf/ton. Water saturation in coals decreased from 100% to values between 20 and 80%, depending on location. The decrease in water saturation improved gas relative permeability to values as much as 0.8.

As a result of primary depletion and matrix shrinkage, permeability of coal seams increased between 10 and 40% compared to their original, which varied between 1 and 10 md depending on depth and coal seam. Calculated permeabilities and porosities were found to be close to the values reported in the literature for Black Warrior coals. Existing effective permeabilities calculated for gas and water at existing saturations showed that permeabilities to gas are moderate in Pratt and Mary Lee groups; however, they are very low, less than 1 md, for the Black Creek group.

Since the wells were fractured, skin and fracture lengths were calculated in matching process. Fracture lengths calculated using skin showed similar values reported in the literature for these coals. Based on the literature, permeability anisotropy that is controlled by induced-fractures was assumed to be in the N 70–90 E directions.

Since history matching was performed for 20 completions in Pratt, 92 completions in Mary Lee, and 45 completions in Black Creek coal groups, compiled results brought the same amount of data for initial and existing conditions of each of the reservoir parameters. However, existing conditions are more important for future forecasts and models related to degasification and emissions. Therefore, basic statistical values and quartile values of each of the parameters of coal groups are reported in tables. These results can be used, as shown in Section 5, to build parameter distributions for probabilistic simulations of degasification efficiency and also can be used in conjunction with geological considerations to calculate potential future methane emissions in operating mines, reducing the potential for ignitions and explosions and improving worker safety.

Supplementary Material

Refer to Web version on PubMed Central for supplementary material.

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Nomenclature

A_D	drainage area (acres)
B_w	water formation volume factor (bbl/stb)
E	Young's modulus (psi)
ε	max. strain as P approaches 0
h	net pay thickness (ft)
k	permeability (md)
k_{eg}	gas effective permeability (md)
k_{ew}	water effective permeability (md)
k_o	initial permeability (md)
k_{rg}	relative permeability to gas
k_{rw}	relative permeability to water
N_g	gas exponent (Corey equation)
N_w	water exponent (Corey equation)
$m(P)$	gas pseudo-pressure (psi^2/cp)
μ_w	water viscosity (cp)
$Ø$	porosity
$Ø_o$	initial porosity
$\dot{P}$	average reservoir pressure (psia)

$\boldsymbol{P_{\mathrm{d}}}$	desorption pressure (psi)
$\boldsymbol{P_{\varepsilon}}$	pressure at 50% of maximum matrix strain (psia)
$\boldsymbol{P_{\mathrm{L}}}$	Langmuir pressure parameter (psia)
$\boldsymbol{P_{\mathrm{o}}}$	initial pressure
$\boldsymbol{P_{\mathrm{wf}}}$	bottomhole flowing pressure (psia)
$\boldsymbol{q_{\mathrm{g}}}$	gas rate (mscf/d)
$\boldsymbol{q_{\mathrm{w}}}$	water rate (bbl/day)
$\boldsymbol{r_{\mathrm{e}}}$	external radius (ft)
$\boldsymbol{r_{\mathrm{w}}}$	wellbore radius (ft)
$\boldsymbol{s}$	skin
$\boldsymbol{S_{\mathrm{w}}}$	water saturation (%)
σ	effective stress (psi)
$\boldsymbol{T}$	temperature (R)
$\boldsymbol{V(P)}$	gas content (scf/ton)
$\boldsymbol{V_{\mathrm{L}}}$	Langmuir volume parameter (scf/ton)
$\boldsymbol{X_{\mathrm{f}}}$	fracture half-length (ft)
γ	Poisson’s ratio

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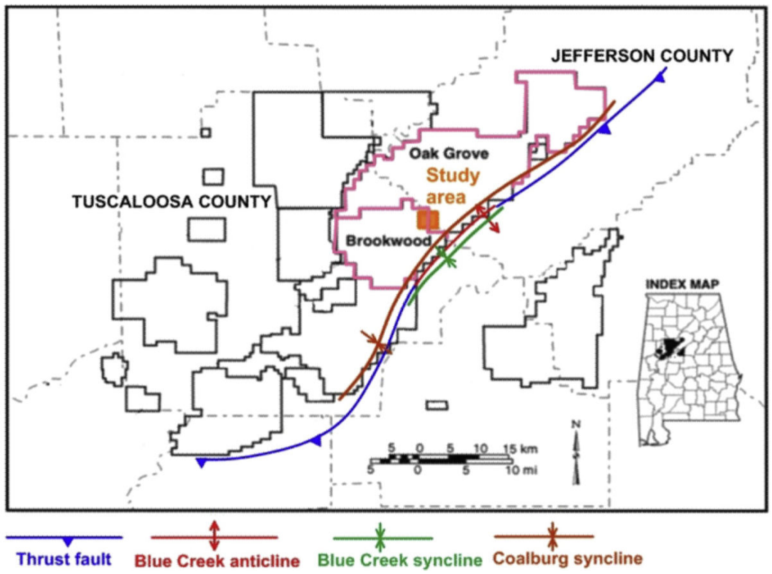

Fig. 1.

Coalbed methane fields in west-central Alabama (shown by solid black lines), major fault and folds along the upturned margin of the basin, and location of the study area between the Brookwood and Oak Grove fields (modified from Pashin and Groshong, 1998).

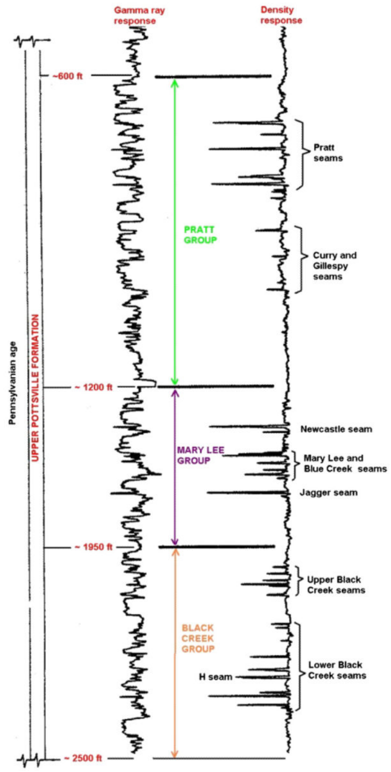

Fig. 2.
A typical well log showing gamma ray and density log responses of Upper Pottsville coals. The figure also shows the seams within each coal group and their approximate depth intervals within the study area.

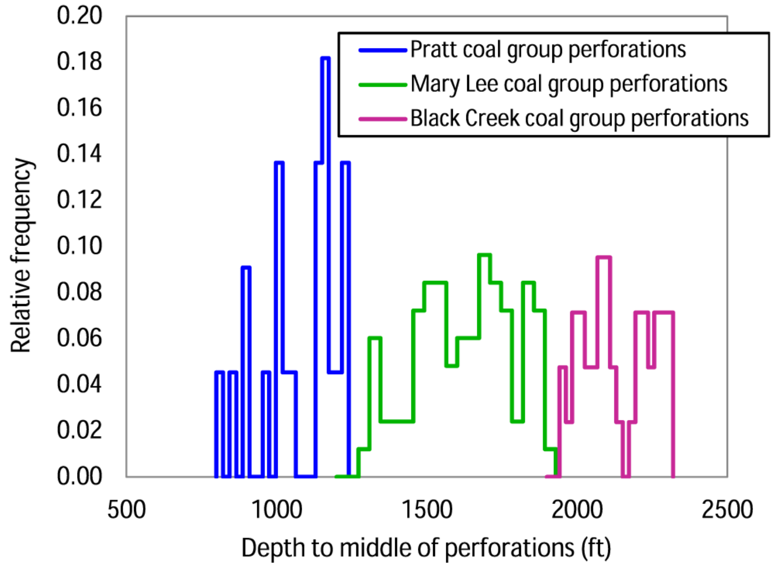

Fig. 3.
Completion depth intervals of each coal group in the study area.

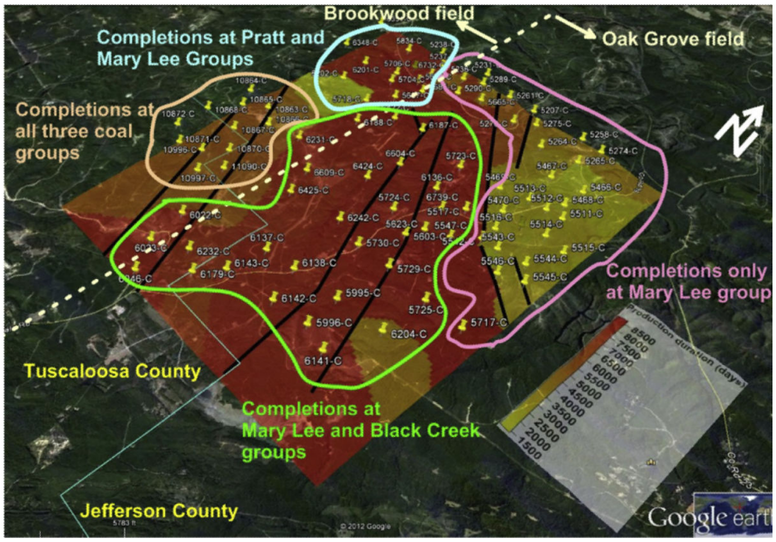

Fig. 4.

A detailed picture showing the study area, field boundary, and location of wells with their permit names and their completion intervals. The image overlay is the production duration of the wells as of the last data recording at the beginning of 2012, and solid black lines are the normal faults detected within the area.

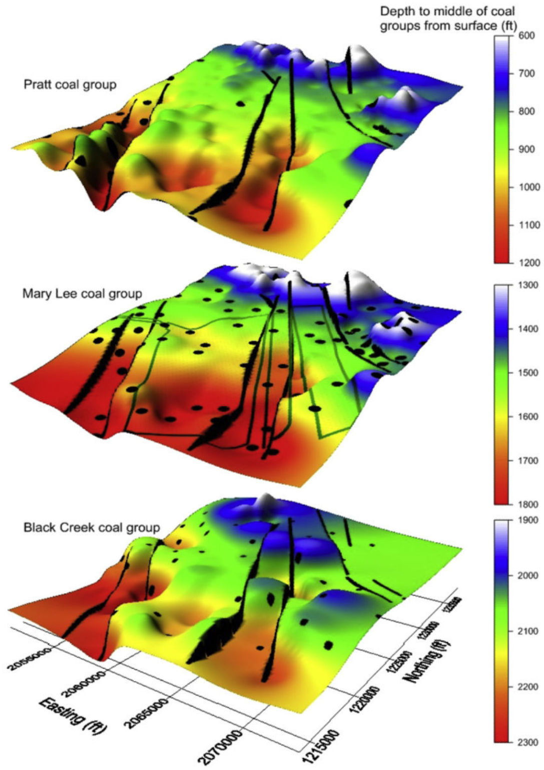

Fig. 5.

3-Dimensional depth view of coal groups studied in this paper. The variations in these figures show the changes of coal depths from surface and the displacements due to structural faults. Each figure also shows the locations of well completions within each of them. Mary Lee group’s figure in the middle shows the boundaries of the coal mine.

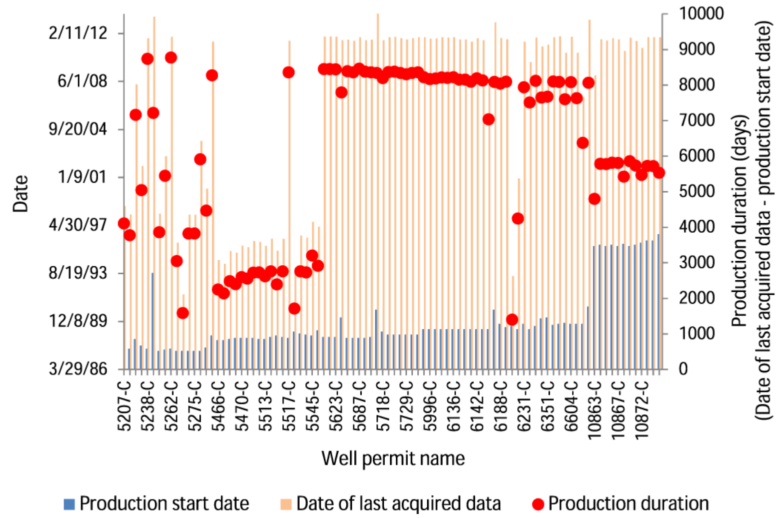

Fig. 6.

Production start dates, production durations, and the date at which the last data was recorded at the time of this work as shown in graphical form for each wellbore. This plot shows that a majority of wells were drilled in the 1980s and the remainder in the 1990s. Most wells have been producing for about 8000 days.

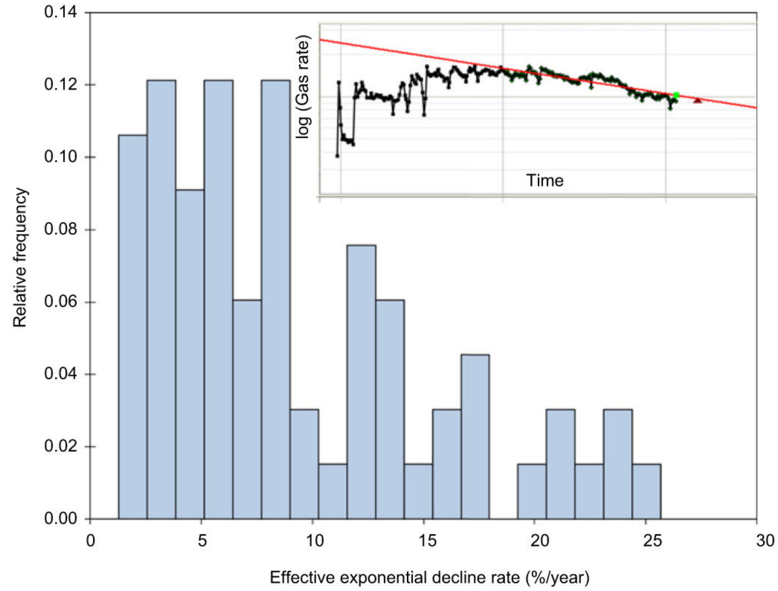

Fig. 7.
Exponential decline rates of the wells determined by conventional decline curve analyses. The inset is a logarithm of gas rate versus time plot of one of the wells given as an example to show exponential decline.

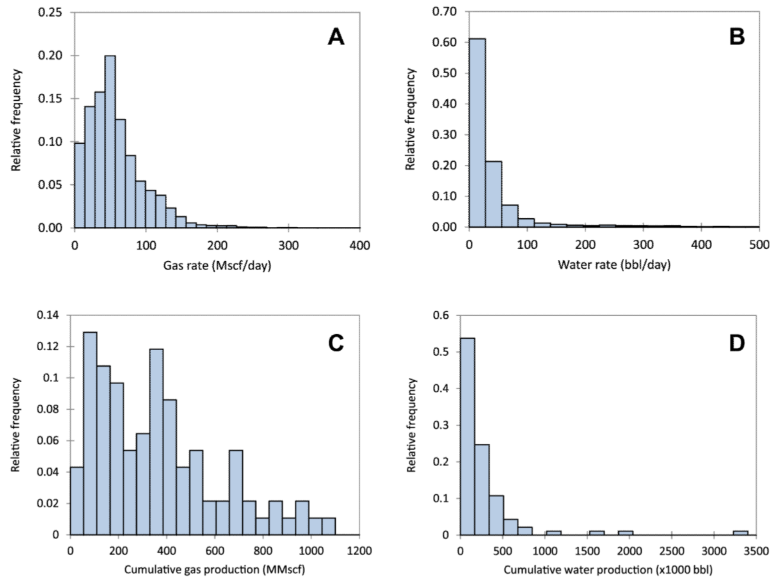

Fig. 8.

Histograms of methane rate (A), water rate (B), cumulative methane production (C), and cumulative water production (D) plotted from the data of all wells in the study area. Maximum methane and water rates reported in the text were not included in the plots since they were outside of the main data population. However, they were included in the reported mean and standard deviation values.

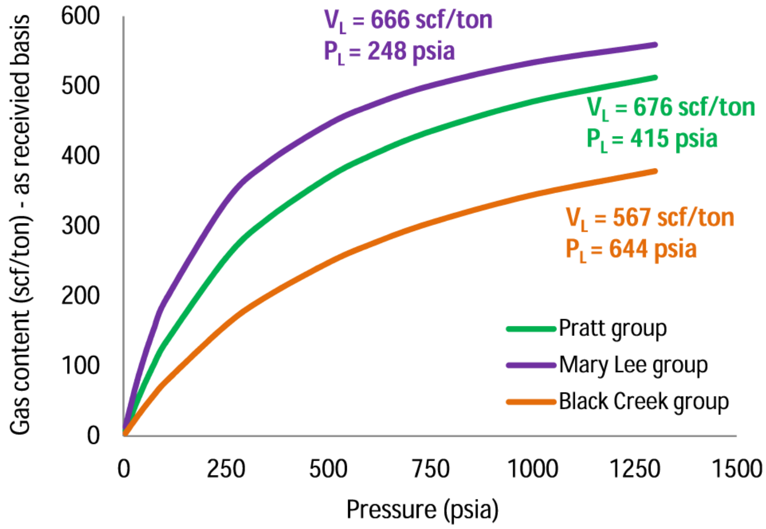

Fig. 9.

Langmuir isotherms and their parameters determined for each of the coal groups.

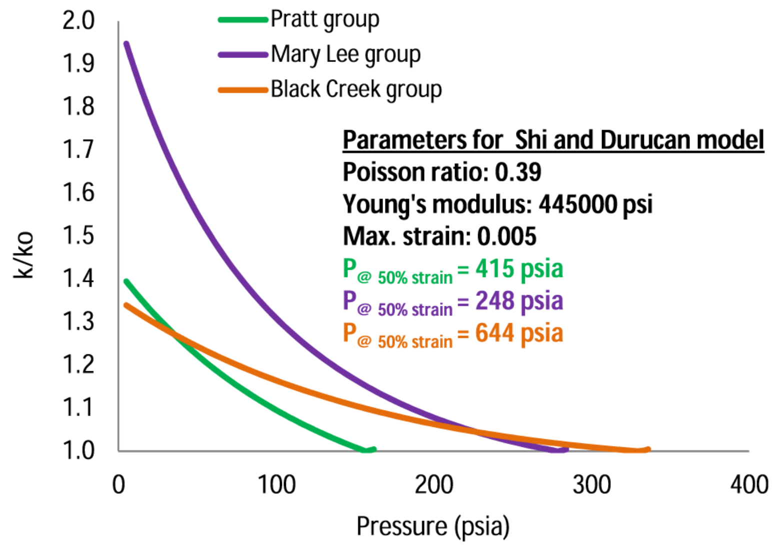

Fig. 10.

Estimated permeability increase in Pratt, Mary Lee, and Black Creek coal groups as a function of pressure change.

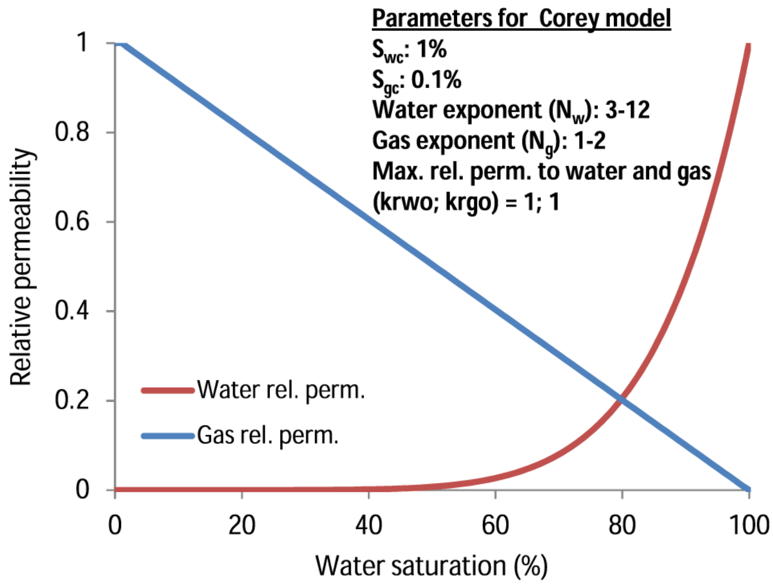

Fig. 11.
Relative permeability curves and Corey model parameters used.

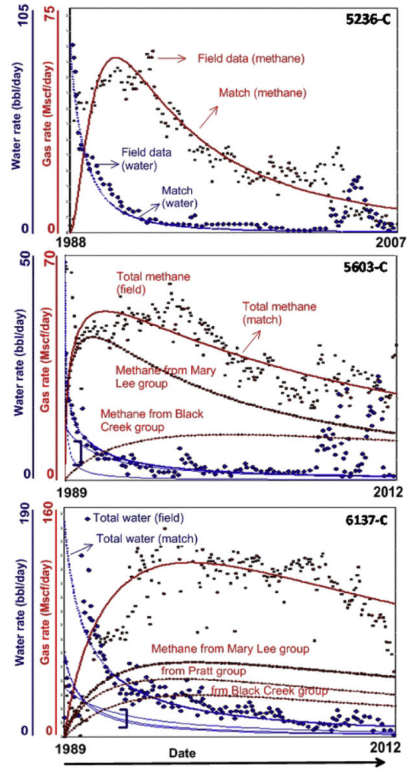

Fig. 12.

Example history match results from wells that are completed in one, two, and three layers. The bracket “]” shows water rate predictions contributed from each coal group.

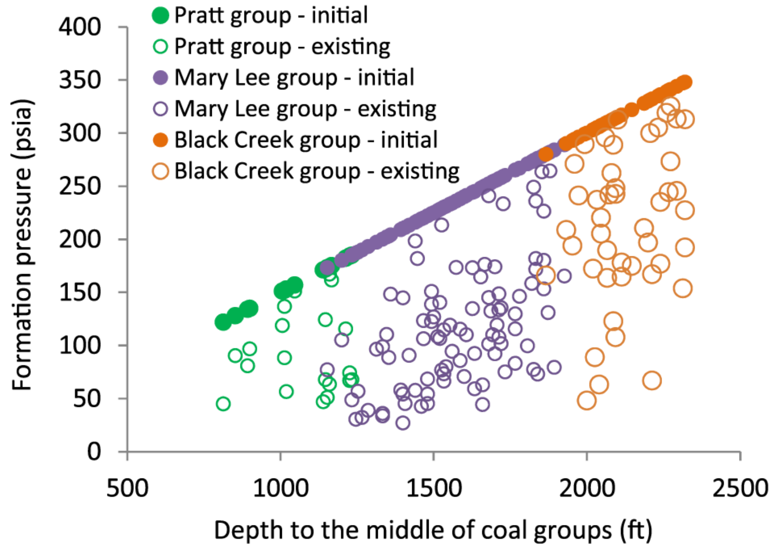

Fig. 13.

Calculated initial pressures and estimated existing pressures of the coal groups, from history matching (based on 0.15 psi/ft pressure gradient).

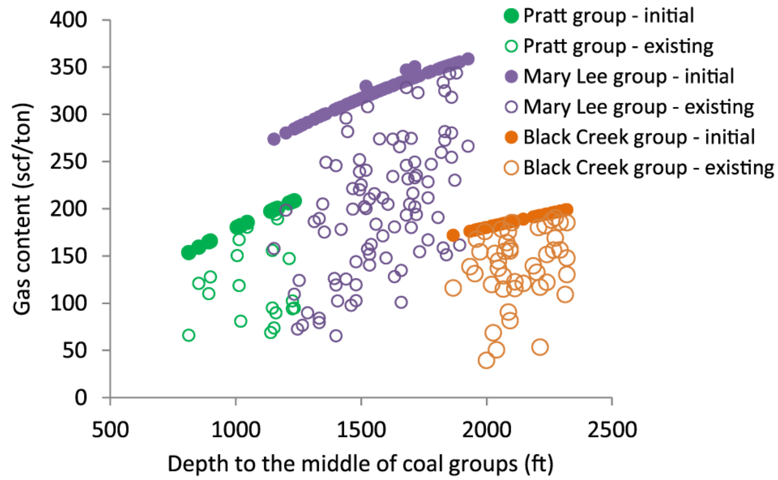

Fig. 14.

Calculated initial gas contents of the coals using initial pressures and the isotherms given in Fig. 9. Circles are existing gas contents based on existing pressures.

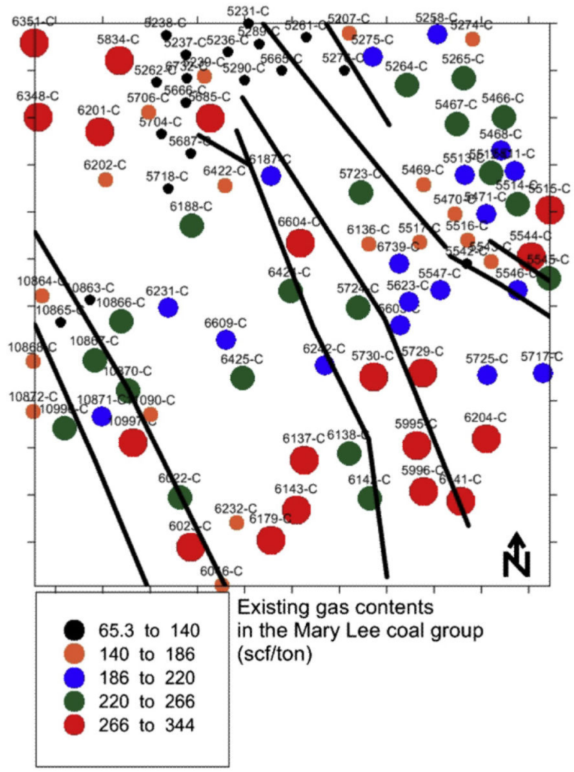

Fig. 15.

Spatial distribution of predicted existing gas contents within the Mary Lee coal group in the study area. In the sorted class map, symbol sizes were scaled according to their magnitude.

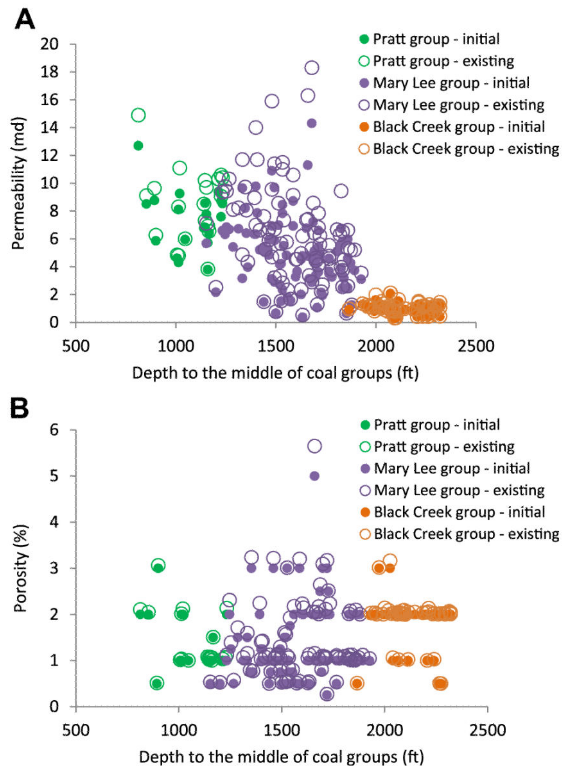

Fig. 16.
Initial and existing permeability (A), and initial and existing porosity (B) of coal groups estimated using production history matching.

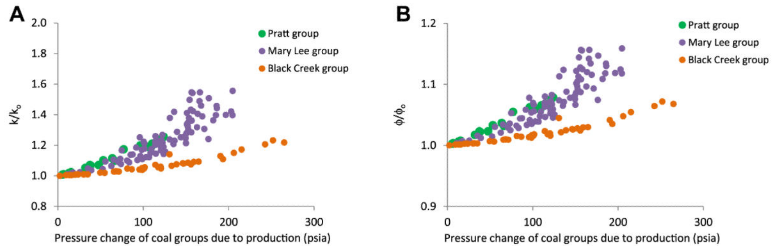

Fig. 17.

Fractional changes in permeability (A) and porosity (B) in coal groups compared to initial values as a result of matrix shrinkage. Presented data points correspond to each of the well locations in the study area.

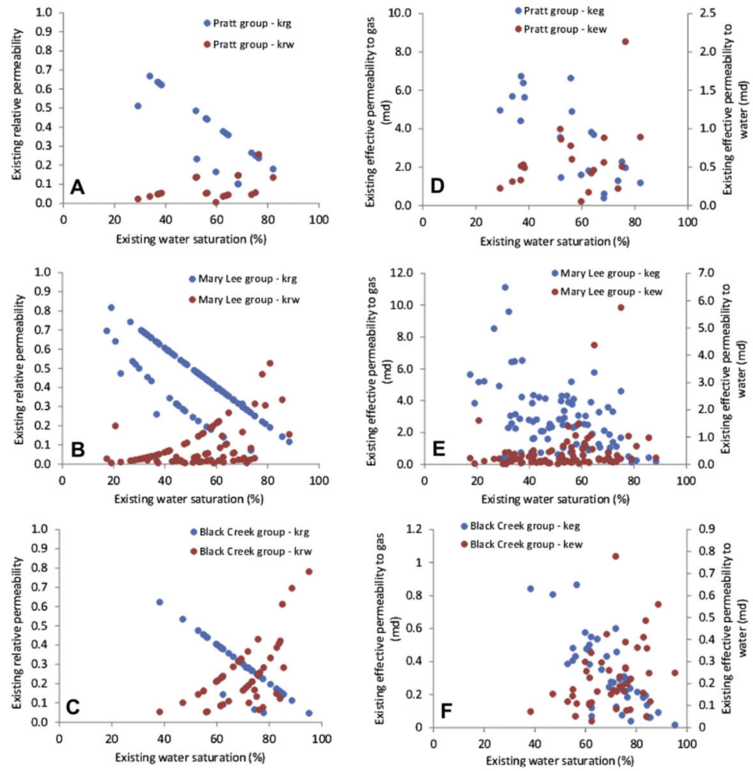

Fig. 18.
Existing relative (A–C) and effective permeabilities (D–F) to gas and water in Pratt, Mary Lee, and Black Creek coal groups.

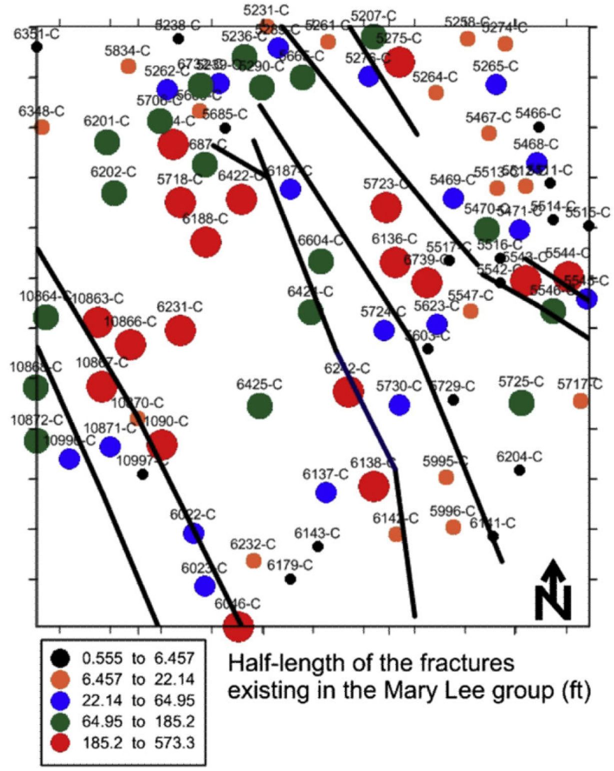

Fig. 19.
Spatial distribution of calculated hydraulic fracture half-lengths in the Mary Lee coal group within the study area. In the sorted class map, symbol sizes were scaled according to their magnitude.

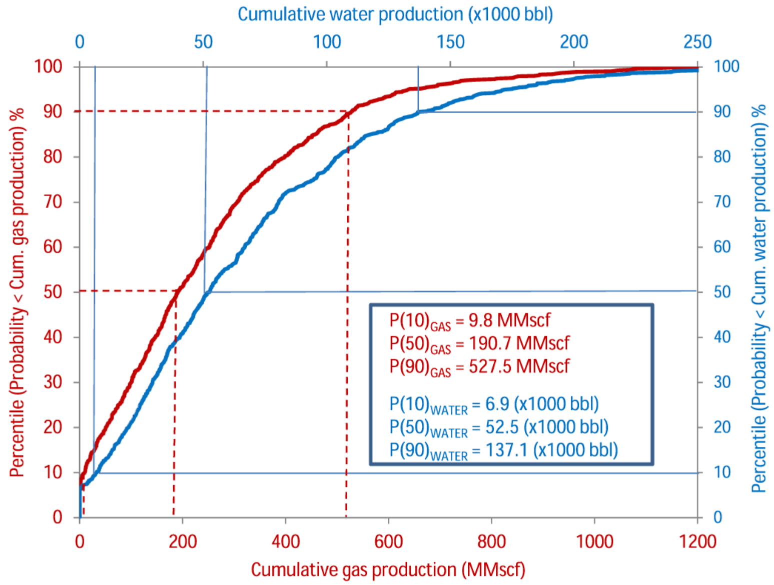

Fig. 20.

Cumulative frequency histogram of gas and water productions estimated using the values in Table 4 with a stochastic approach. The percentile values are given in the inset table.

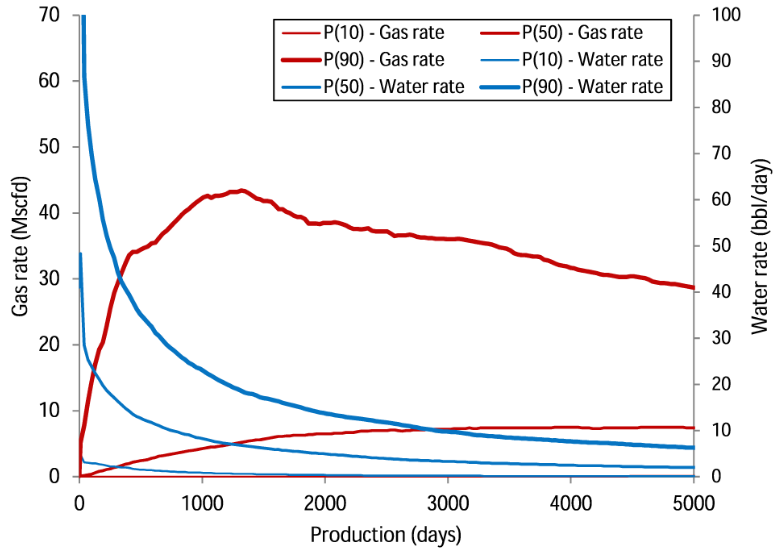

Fig. 21.
Gas and water rates (P10, P50 and P90) predicted using stochastic simulation and the input values given in Table 4.

Table 1

Basic statistics and quartile values of existing coal reservoir and fluid-transport-related parameters in each coal group.

Coal group and variable	Minimum	Maximum	Mean	1st quartile	Median (2nd quartile)	3rd quartile	Standard deviation
Pratt – P (psia)	44.90	167.15	93.51	66.07	84.45	120.14	38.76
Mary Lee – P (psia)	26.98	264.19	116.55	74.42	109.05	148.18	57.09
Black Creek – P (psia)	47.99	325.22	214.70	172.17	220.39	271.01	72.34
Pratt – $V(P)$ (scf/t)	72.53	251.97	156.19	116.80	150.80	198.64	56.38
Mary Lee – $V(P)$ (scf/t)	65.35	343.53	202.40	153.72	203.40	249.10	69.05
Black Creek – $V(P)$ (scf/t)	39.32	190.26	138.64	119.61	144.57	167.94	38.14
Pratt – k (md)	3.83	14.90	8.42	6.48	8.79	10.23	2.65
Mary Lee – k (md)	0.53	18.30	6.24	3.84	5.72	8.09	3.53
Black C – k (md)	0.32	2.12	1.03	0.81	1.06	1.22	0.40
Pratt – k_{rg}	0.10	0.67	0.39	0.24	0.37	0.54	0.19
Mary Lee – k_{rg}	0.07	0.82	0.44	0.31	0.44	0.57	0.16
Black Creek – k_{rg}	0.05	0.62	0.29	0.17	0.28	0.39	0.13
Pratt – k_{rw}	0.01	0.26	0.08	0.04	0.05	0.14	0.06
Mary Lee – k_{rw}	0.01	0.53	0.08	0.02	0.04	0.08	0.10
Black Creek – k_{rw}	0.05	0.78	0.24	0.12	0.21	0.29	0.16
Pratt – k_{eg} (md)	0.39	6.73	3.45	1.56	3.62	5.13	2.12
Mary Lee – k_{eg} (md)	0.14	11.11	2.80	1.15	2.50	3.88	2.07
Black Creek – k_{eg} (md)	0.02	0.87	0.32	0.18	0.27	0.46	0.21
Pratt – k_{ew} (md)	0.05	2.13	0.60	0.33	0.51	0.80	0.45
Mary Lee – k_{ew} (md)	0.02	5.75	0.43	0.11	0.20	0.44	0.78
Black Creek – k_{ew} (md)	0.03	0.78	0.22	0.12	0.19	0.27	0.15
Pratt – Ø (%)	0.52	3.07	1.40	1.02	1.07	2.02	0.63
Mary Lee – Ø (%)	0.27	5.65	1.42	1.01	1.11	2.01	0.85
Black Creek – Ø (%)	0.50	3.16	1.87	2.00	2.02	2.05	0.54
Pratt – S_w (%)	29.20	82.12	56.22	38.33	58.01	68.38	16.01
Mary Lee – S_w (%)	17.37	88.44	51.63	39.37	52.88	62.74	16.13
Black Creek – S_w (%)	38.30	95.22	70.30	61.61	72.12	77.62	11.82

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Table 2

Basic statistics and quartile values of skin and fracture half-lengths existing in each coal group.

Coal group and variable	Min.	Max.	Mean	1st quartile	Median (2nd quartile)	3rd quartile	Standard deviation
Pratt – skin	−0.7	−6.9	−4.2	−6.1	−4.0	−2.7	2.0
Mary Lee – skin	−0.1	−7.7	−4.3	−5.8	−4.6	−3.0	1.8
Black Creek – skin	−1.1	−7.1	−4.1	−5.8	−3.9	−2.5	1.7
Pratt – Frac. half-length (ft)	1.0	513.0	119.8	7.9	27.6	214.1	160.3
Mary Lee – Frac. half-length (ft)	0.6	573.3	100.0	9.2	44.8	160.9	130.0
Black Creek – Frac. half-length (ft)	1.6	607.7	103.1	6.2	23.8	161.6	144.8

Table 3

Statistics of drainage area (A_D) calculated for each coal group.

Coal group and variable	Min.	Max.	Mean	1st quartile	Median (2nd quartile)	3rd quartile	Standard deviation
Pratt – A_D (acres)	24.0	117.0	76.1	51.0	76.0	95.0	26.7
Mary Lee – A_D (acres)	6.0	173.0	58.4	25.0	50.0	81.0	39.0
Black Creek – A_D (acres)	12.0	136.0	59.8	35.3	54.0	77.3	32.5

Table 4

Parameter values and their ranges used in probabilistic well deliverability calculation for Mary Lee coal group.

Parameter	Unit	Values				Distribution
P_i	psia	Mean:	116.6	Std. Dev:	57.1	Normal
V_L (CH_4)	scf/ton	Constant:	666			
P_L (CH_4)	psia	Constant:	248			
$V(P)$	scf/ton	Constant:	291.5			
A_D	acres	Mean:	58.34	Std. Dev:	39.01	Normal
h	ft	Constant:	22			
Ø	%	Mean:	1.42	Std. Dev:	0.85	Normal
S_w	%	Constant:	100			
T	oF	Constant:	86			
k	md	Mean:	6.24	Std. Dev:	3.53	Normal
s		Mean:	−4.3	Std. Dev:	1.8	Normal
S_{wc}	%	Constant:	1			
S_{gc}	%	Constant:	0.1			
N_w		Min:	3	Max:	12	Uniform
N_g		Min:	1	Max:	2	Uniform