CHAPTER 8.—FORECASTING GAS EMISSIONS FOR COAL MINE SAFETY APPLICATIONS

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In This Chapter

- ✓ Measuring the gas content of coal
- ✓ Predicting gas emissions based on geologic and coal reservoir property data
- ✓ Determining the gas storage capacity of coalbeds and other gas-bearing strata
- ✓ Methane drainage borehole monitoring to forecast the remaining gas-in-place and the influence on mine emissions
- ✓ Forecasting gas emissions during mining as a function of mining parameters

and

- ✓ Gas emission prediction based on numerical simulation

This chapter provides guidelines for determining the gas content of coalbeds, estimating the gas-in-place, and predicting gas flow and emissions before and during coal mining operations. The techniques are discussed briefly in the following sections. However, detailed information on the techniques is provided in the cited references.

INTRODUCTION

Coalbed methane, if not properly controlled in the underground mine environment, is a safety concern due to the potential risk for an explosion. This is a particular problem during longwall mining, where the high rate and volume of coal extraction can result in the release of large amounts of methane from the mined coalbed and other adjacent gas-bearing strata. The variability and potential hazards of these sometimes unexpectedly high gas flows provide the impetus to develop methods to predict methane emissions into the underground workplace. A forecast of the volume of gas that might be released during coal mining is helpful for designing ventilation systems and for implementing optimum methane drainage strategies to help mitigate expected gas emission problems.

A complete assessment of the need for methane drainage prior to mine development generally requires both an empirical and a theoretical approach. If there are active mines in the general area with similar geologic conditions and coal characteristics, a review of gas problems in those mines provides an initial insight into the level of gas emissions to be expected at a new location. In addition, relatively simple methods exist to determine the in situ gas content (volume of gas per unit weight of coal) of the coalbeds in a particular mining area, as well as the gas-in-place (volume of gas in the coalbed(s) within a defined geographic area).

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More sophisticated reservoir engineering methods are also available not only to estimate the gas-in-place, but also to simulate gas flow patterns in the mining horizon, as well as in the surrounding strata. With a reservoir modeling approach, gas flow to various configurations of methane drainage boreholes can be investigated to optimize the interception and extraction of coalbed methane before it can enter the mine ventilation system.

Although potentially providing valuable insights about gas flow and methane drainage in the mining environment, the site-specific input data required for reservoir modeling is not routinely available at many, if not most, mine sites. For this reason, it is recommended that if the reservoir modeling approach is anticipated due to high in situ gas contents, then the necessary geologic, engineering, and reservoir data should be obtained early so that methane drainage options can be evaluated before methane emission problems become acute.

Forecasting gas emissions requires knowledge of the relationships among gas storage in coal (and adjacent strata), the factors affecting gas emissions, and the techniques used to predict emissions.

METHANE CONTENT OF COAL

The gas content of coal can be measured or estimated using various techniques. These techniques usually fall into two categories: (1) direct methods that actually measure the volume of gas released from a coal sample (preferably wire line core) sealed in a desorption canister, and (2) indirect methods based on empirical correlations or laboratory-derived gas storage capacity data from sorption isotherms. An extensive review of direct techniques for gas content measurement for coal was published by Diamond and Schatzel [1998]. One of the most commonly used methods to determine the gas content of coal is the U.S. Bureau of Mines direct method [Diamond and Levine 1981; Diamond et al. 1986]. Properly conducted direct-method testing of coal cores provides relatively accurate estimates of in-place gas contents for most mine planning purposes while allowing for resource evaluation at a reasonably low cost. A modified-direct-method procedure [Ulery and Hyman 1991] provides an increased level of accuracy, but at a higher level of instrumentation sophistication, procedural complexity, and cost.

Direct-method testing of coal cores provides sufficient estimates of in-place gas contents for most mine planning purposes. Greater accuracy can be obtained by using the modified direct method.

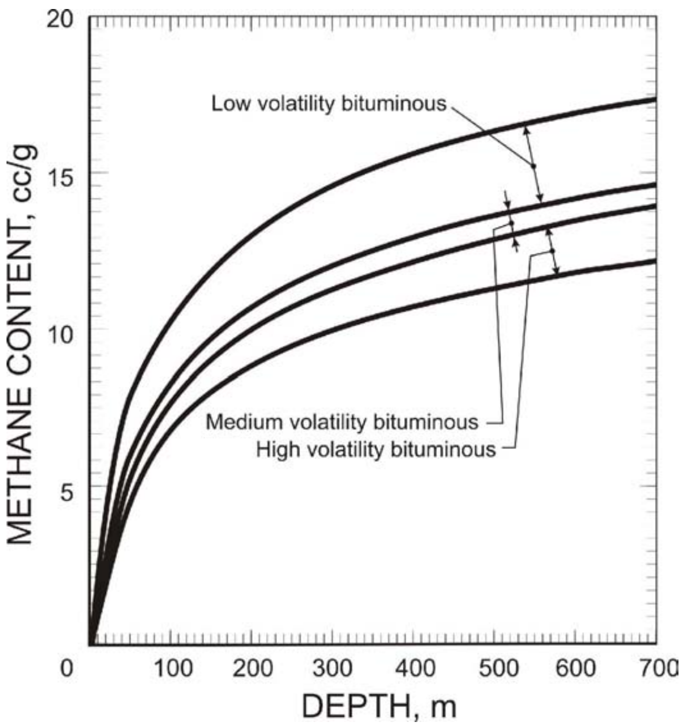

Figure 8–1.—Methane content as a function of depth and coal rank (modified from Kim [1977]).

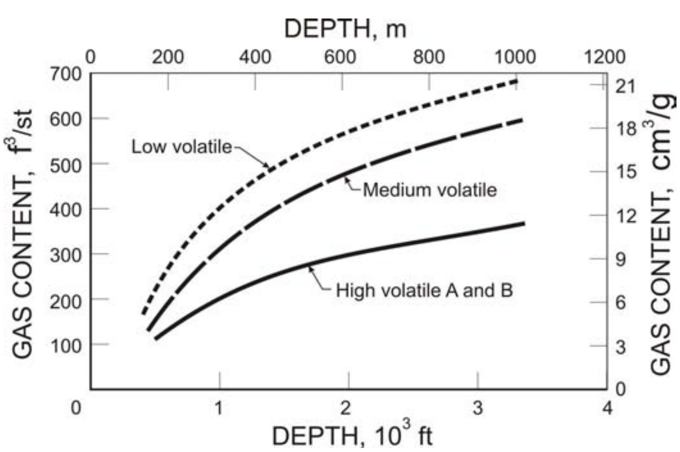

Figure 8–2.—Gas content versus depth and coal rank, Black Warrior Basin, Alabama (McFall et al. [1986]).

In the absence of extensive measured gas contents in an area of interest, an alternative approach to obtain the gas content is to use the relations proposed by Kim [1977] based on gas content determinations from adsorption analysis on different coals of various ranks and depths (Figure 8–1). This approach can be considered in parts of a basin where coal samples are initially not available for direct gas content testing. However, it is important to note that these are only estimated values and should be confirmed with subsequent direct gas content testing within the actual area of interest.

For estimating in-place gas contents for a specific area, regional gas content data on individual coal samples can be used along with data on coal rank and/or depth to construct curves such as those in Figure 8–2. Such curves are generated for a particular coalbed or closely associated group of coalbeds and can be used to estimate gas content values only if the rank or depth are known for the coalbed of interest. As an example, the graph in Figure 8–2 presents such curves for the Black Warrior Basin in Alabama [McFall et al. 1986]. Coal lithotype characteristics also affect the methane content of coal. For instance, significantly higher methane capacity was observed for bright bands (850 ft^3/ton) versus dull bands (570 ft^3/ton) in the same coalbed during an evaluation of compositional effects on coals from western Canada [Lamberson and Bustin 1993]. Total gas content varied with the amount of vitrinite and liptinite, which usually offer high methane storage capacity, whereas no obvious relationship was observed with the inertinite content. Some studies report increases in gas yield with fusain content, which tends to allow rapid desorption of methane [Creedy 1986]. Despite these examples, while the general influence of coal lithotype on gas content is of interest, it cannot be sufficiently quantified for use as a predictive gas content method.

Estimated gas contents should only be used for preliminary assessments. They are not a substitute for site-specific gas content determinations.

GAS-IN-PLACE CALCULATION

One of the key steps in forecasting gas emissions during and after mining is to calculate the volume of gas-in-place that will potentially migrate to the underground mining environment. During mining, these emissions are primarily from the mined coalbed, whereas postmining emissions include not only the mined coalbed (ribs and pillars), but also gas-bearing strata above (gob) and below the mined coalbed.

The simplest method for calculating the gas-in-place for coalbeds is based on commonly available geologic mapping data for the mine site and the site-specific gas content data [Diamond 1982], as follows:

$$GIP_c = (\rho \times h \times A)GC, \tag{1}$$

where GIP_c = coal gas-in-place, ft^3;
ρ = coal density, tons/acre ft;
h = coal thickness, ft;
A = area, acres;
and GC = gas content (volume-to-mass ratio), ft^3 gas/ton of coal.

Depending on the variability of measured gas contents within the area of interest, multiple gas-in-place calculations for individual zones (based on gas content versus depth and/or coal rank data as shown in Figure 8–2) may be necessary to obtain the best total gas-in-place value. For gas-bearing strata other than coal (organic shales, etc.) where the gas is primarily stored by adsorption (as in coal) or for low matrix permeability rocks such as siltstones where the stored gas cannot readily escape from a core sample before it is sealed in a desorption canister, the gas-in-place estimate can be calculated as follows [Diamond et al. 1992]:

$$GIP_r = (h \times A)GC, \tag{2}$$

where GIP_r = rock gas-in-place, ft^3;
h = rock strata unit thickness, ft;
A = area, ft^2;
and GC = gas content (volume-to-volume ratio), ft^3 gas/ft^3 rock.

For high matrix permeability rock units, like some sandstones, where the direct-method-type gas content determinations are not appropriate, traditional reservoir engineering methods for estimating the volume of gas-in-place are more appropriate. These methods may include the use of well logs, laboratory reservoir property core testing, and well/production testing.

There are various approaches to determine an area's in-place gas volume. The preference usually depends on data availability, degree of sophistication required in the analysis, and the technical background of the personnel conducting the analysis.

Reservoir-analysis-based approaches may also be used to determine the gas-in-place for coalbeds in a specific geographic area. These approaches relate the volume of gas in the reservoir at reservoir conditions to the volume at STP[2] conditions and use the differences in remaining gas volumes as the reservoir pressure is depleting. Although reservoir-based approaches can be an essential part of gas-in-place calculations, particularly for mines that are considering marketing the produced methane, these approaches require significantly more data (at a relatively high cost) than is usually available for most mine safety applications. Two of the reservoir-analysis-based methods for calculating gas-in-place are the volumetric calculation and the material balance calculation.

The volumetric method of calculation (Equation 3) is very similar to Equation 1 above. In addition to estimating the gas-in-place (free gas, if any, and adsorbed gas) for the coal in an area based on the direct-method gas content data, this method also calculates the amount of gas in the cleats and fractures by taking into account the water saturation (Swf_i), cleat/fracture porosity (ϕ_f), and gas formation volume factor (Bg_i).[3]

$$G_i = Ah\left(\frac{43560\phi_f\left(1-Swf_i\right)}{Bg_i}+1.359Cg_i\rho_c\left(1-f_a-f_m\right)\right) \quad (3)$$

Another reservoir engineering method of estimating gas-in-place is the use of material balance calculations derived for coalbeds from conventional material balance equations. Terms are added to the equations to account for desorption mechanisms. However, this is an iterative technique and requires more data and calculation complexity than the previous methods. Details on the use of material balance calculations for coalbed methane applications were published by King [1993].

[2]Standard temperature and pressure.
[3]Refer to McLennan et al. [1995] for more information on the volumetric method of calculation and for further definition of the terms in Equation 3.

FORECASTING REMAINING GAS-IN-PLACE FROM PRODUCING METHANE DRAINAGE BOREHOLES IN THE AREA OF INTEREST (PRODUCTION DECLINE ANALYSIS)

Analysis of production decline trends for premining methane drainage boreholes in an area of interest, when combined with the original gas-in-place estimate, can provide a reasonably accurate estimate of the volume of gas remaining in the coalbed and available for flow to the mining environment. This method is widely accepted in the natural gas industry due to its ease of application and requires only the gas production histories from existing wells. However, in contrast to conventional gas reservoirs, it usually takes a long time (potentially a year or longer) for a coalbed methane borehole to exhibit a production decline. Thus, there may be a long delay before the data can be analyzed. Also, borehole spacing, formation permeability, desorption properties of coal, and production problems not related to the reservoir can affect the production profile.

Production decline analysis can be used for forecasting the future methane flow and emission potential from a coalbed by analyzing the time-resolved production trends of methane drainage boreholes. However, these boreholes are generally completed only at the mined coalbed interval, which makes analysis for mine safety applications more complex and difficult. During longwall mining, gas emissions in the relaxed strata are usually a combination of different sources of migrating gas (from coalbeds plus other gas-bearing strata in the overburden and underburden) due to horizontal and vertical fracturing of the surrounding strata. Therefore, it is difficult to compare the estimated gas flow and emission rates from decline analysis of methane drainage boreholes completed in the mined coalbed with the actual gas emissions observed during mining. The result is that the forecasts of gas emissions based on decline curve analysis of commercial coalbed methane wells (or vertical degasification wells), completed at a single interval (the mined coalbed), will likely underestimate the volume of gas that will be released from the mined coalbed and surrounding strata into the mine environment.

In a case where one can be sure that there is no gas source other than the mined coalbed, the decline curve analysis technique may be applicable for estimating the remaining gas-in-place for that coalbed that might still migrate to the ventilation system during future mining activities. In order to be able to use decline curve techniques for this situation, all or most of the criteria below need to be met for a high degree of confidence in production forecasts:

- Decreasing gas and water rates
- A stable slope in gas rates for at least 6 months
- A length of producing well life greater than 2 years
- Bounded wells and well spacing

It is also recommended that decline-based gas-in-place and future methane flow/emission potential projections be compared against projections from volumetric or other available analytical techniques [Hanby 1991].

Alternatively, type-curve matching techniques are a reservoir engineering tool in which the solutions of complex equations for various situations are represented in graphical form. The techniques rely on matching the actual gas production data plots (prepared with the same set of units and graphical form as in the type-curves) to the theoretical curves. These techniques can also be used to analyze production decline curves to predict remaining gas-in-place and future emissions for mine safety assessments [Chen and Teufel 2000]. In addition, if the gas production is exclusively from the coalbed to be mined, type-curve analysis can provide other reservoir information that needs to be determined for emission forecasting studies (e.g., modeling).

In summary, type-curves can contribute to:

- Stimulation (fracturing) effectiveness diagnosis
- Recovery efficiency (recovery factor based on initial gas-in-place)
- Estimation of reservoir flow properties (permeability, flow capacity, etc.)
- Reservoir storage properties
- Future prediction of production

Both production decline analysis and type-curve matching techniques can be used to analyze methane drainage boreholes for future production rates and thus predict the remaining gas-in-place at the time of mining. However, gas emissions from different gas sources may be commingled, especially during longwall mining. Therefore, one can expect higher emission rates during mining compared to what is predicted by the analysis.

PREDICTING GAS EMISSIONS DURING MINING

The main sources for gas (generally predominantly methane) that can be released into the underground mine workings are the mined and adjacent coalbeds and other surrounding gas-bearing strata [Mucho et al. 2000; Diamond et al. 1992]. Mining activities disturb the existing stress equilibrium in the rock mass and create changes to the structural integrity of the affected strata. The mining processes can thus create sudden and unstable gas problems, which may increase the risk of an explosion in the underground workplace. Gas flow from these sources is initiated and maintained by differential pressures between the source (higher pressure) and the mine workings (lower pressure). The flow paths are both the naturally occurring rock joints, faults, and coal cleat, as well as mining-induced fractures in the surrounding strata.

It is generally observed that the amount of gas released during the mining process is greater than that contained in the actual volume of coal mined at the face [Kissell et al. 1973]. This apparent discrepancy is due to the continual emission of gas from the coal that is left in place as ribs and pillars, as well as the migration of gas from the surrounding strata, including the longwall gob [Mucho et al. 2000]. Methane emission rates change over time in the life cycle of a mine because of the interaction of variable geotechnical, mine design, and operational factors. The following mathematical formula by Lunarzewski [1998] addresses this phenomenon and calculates the quantity of gas released into a mine during various stages in the life of a mine:

$$Q(y) = \frac{g}{CA}\left(\left(\sum_{0}^{y+1} C\right)^{m} + 1 - \left(\sum_{0}^{y} C\right)^{m} + 1\right), \tag{4}$$

where $Q(y)$ is the average methane emission (cubic meters of methane) in a year "Y" of the mine's existence, CA is the coal output in 1 year only (tons), C is the total coal output for the life of the mine up to year "Y", and g and m are coefficients dependent upon geological and mining conditions.

The highest gas emissions can be expected as the coal is extracted and the floor and roof strata are relaxed. The instantaneous volume of gas released from all potential sources when 1 ton of coal is extracted can be calculated, and practical experience has shown that gas emissions are related to daily and weekly coal production levels and to the time factor, as follows [Lunarzewski 1998]:

$$Q = a\sqrt{CP} + b, \tag{5}$$

where Q is the total methane emission rate expressed in liters of methane per second, CP is the daily coal production rate in tons, and a and b are empirical constants related to weekly coal production levels and number of working days per week [Lunarzewski 1998].

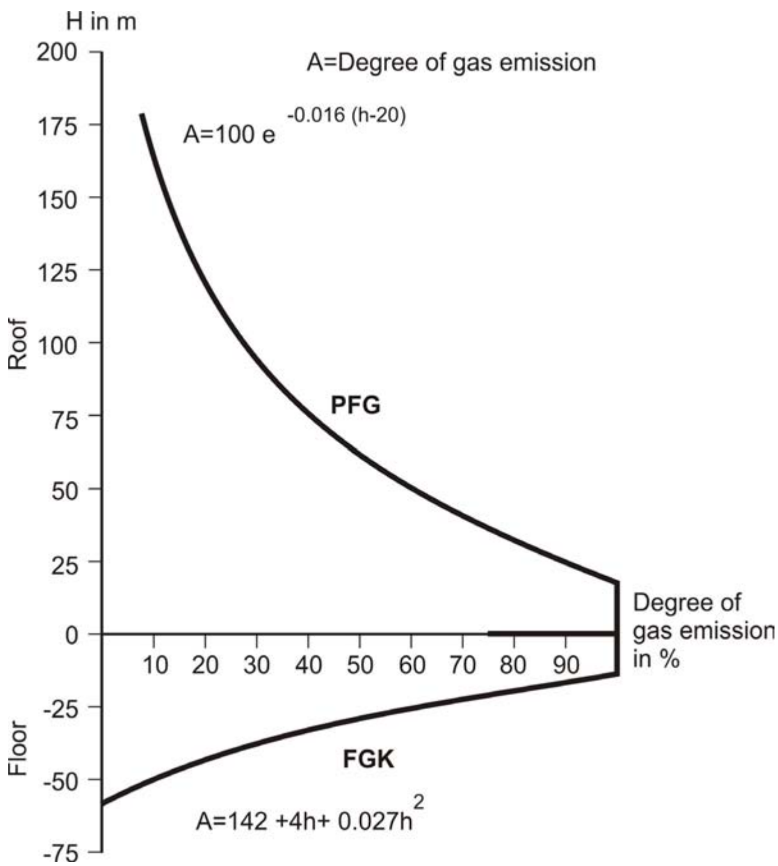

Figure 8–3.—PFG/FGK method to predict gas emissions in a previously disturbed zone [Noack 1998]. PFG = degree of gas emission curve for the roof; FGK = degree of gas emission curve for the floor.

Another empirical method to predict the total gas emissions from longwall mining is the use of degree-of-gas emission curves. Figure 8–3 is an example of a degree-of-gas emission curve for previously disturbed roof and floor strata in a slightly to moderately dipping coalbed [Noack 1998]. In such a condition, the prediction can be made assuming that the emitted methane proportion is not a function of the initial gas content, but rather a function of the geometric location with respect to the longwall face [Noack 1998]. For practical purposes, the upper boundary of the zone from which gas can be released is assumed to be at +541 ft (+165 m), whereas the lower boundary is at -194 ft (-59 m). In the absence of gas emission measurements, a mean degree of gas emission of 75% of the gas content in the mined coalbed is assumed, as is the case for Figure 8–3. Above the coalbed from 0 to 66 ft (20 m) and below the coalbed from 0 to -36 ft (-11 m), the degree of gas emission is assumed to be 100%.

Because these curves are empirical correlations or standard assumed degrees of emissions, there may be considerable variations when they are applied to other locations. As always, it should be remembered that the best information for prediction is the measured data and the derived empirical correlations at a specific site of interest.

On the other hand, if the roof and floor have not been fractured before, the prediction can be based on gas pressure, and thus a remaining gas content. In this case, the proportion of gas emitted depends on the gas pressure (gas content) and the location of the strata. The gas emission prediction for such a situation can be based on the remaining gas profiles, as shown in Figure 8–4. There are three zones designated in the roof and two in the floor, which are characterized by varying the remaining gas gradients.

Based on Figure 8–4, the residual gas pressures are first determined layer by layer in accordance with the mean normal distance of a gas-bearing layer from the mined coal seam. The residual gas pressures are converted to remaining gas contents using the Langmuir isotherm. The difference between the remaining and initial gas contents represents the emitted portion of the adsorbed gas, which is the required value [Noack 1998]. Free gas is then added to this value.

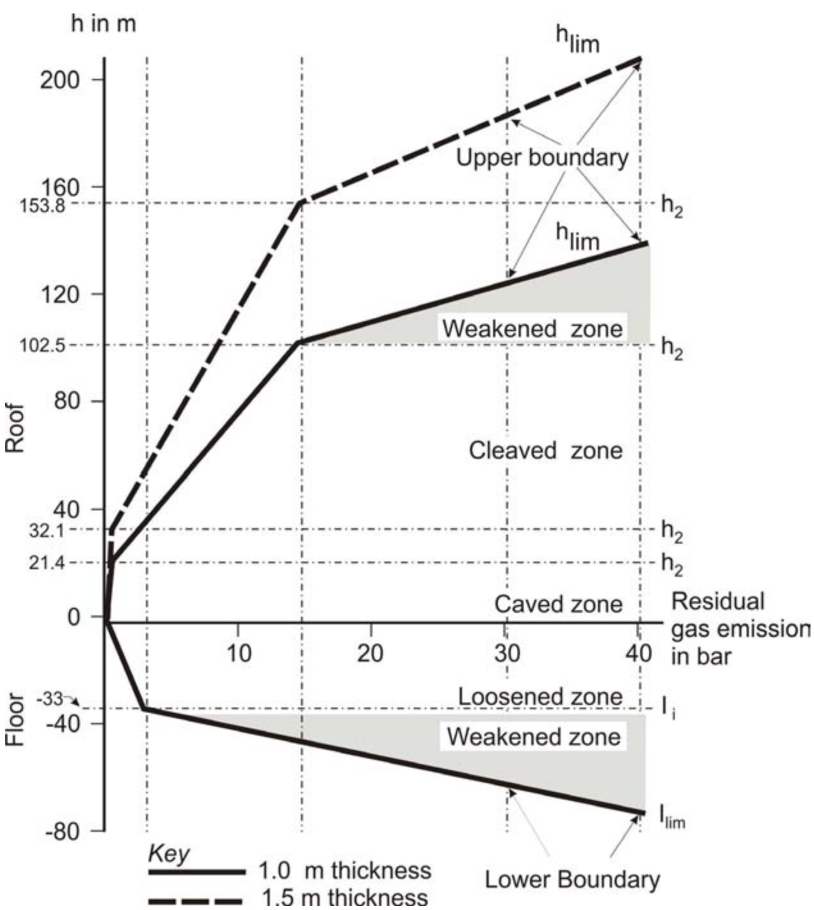

Figure 8–4.—Gas pressure method: residual gas pressure lines are dependent on thickness of the mined coalbed [Noack 1998].

The gas pressure method has the advantage of not defining upper and lower zones strictly compared to the prediction based on the degree of gas emission. Also, this method takes into account both the adsorbed gas and the free gas in the surrounding strata.

There is another method based on using zones of emission, reviewed extensively by Curl [1978]. This model describes methane emissions in terms of the geometry of the zone of emissions, the size of the zone of emissions, and the degree of emissions. The geometry and size of the zone of emissions simply refer to the shape and extent of the zone. The degree of emissions refers to the percentage of desorbable gas that is released into the mine workings at a given location near the coalbed being mined. In this model, underburden emission zones and the degree of emissions are generally more limited in extent. The lateral extent of the zone of emissions is generally limited to the dimensions of the panel. In these models, sandstone units within the emission zone are ascribed 10% of the gas contained in a nearby coalbed of equal thickness, whereas shale is assigned 1% of the gas contained in coalbeds of equal thickness.

Schatzel et al. [1992] used such a model to predict methane emissions from longwall panels. They reported that this approach performed well for longwall panels in Cambria County, PA, but poorly in the Central Appalachian Basin of southwestern Virginia. This suggests that although the simplistic predictive techniques and empirical methods may offer quick calculation advantages, in general they are not sufficiently reliable for making emission estimates given the complex interplay of the geotechnical and mining variables involved. Thus, the use of numerical models to simulate the physics of both the failure mechanics of rock strata and the fluid flow in porous media is more appropriate for obtaining reliable emission estimates, for flexibility in adapting the models to different situations, and for optimizing methane drainage systems and mine designs accordingly.

Simple calculations and empirical models are usually site-specific and are very limited in their capabilities to estimate methane emissions. Realistic numerical simulations offer flexibility, confidence in estimates, and guidance for optimizing methane drainage systems and mine designs.

GAS PREDICTION TECHNIQUES BASED ON NUMERICAL SIMULATION

Reservoir simulation is the process of integrating geology, petrophysics, reservoir engineering, and production operations to more effectively develop and produce hydrocarbon resources. Numerical reservoir simulations can also be useful in mine safety applications. In fact, reservoir simulations are currently the only analytical method that can be used to establish the complex relationships between coalbed methane reservoir properties, methane drainage, and mining operations in a reliable and cost-effective manner. Numerical simulation is also the only practical method to describe how reservoir properties affect both gas and water flow and can address the intricate mechanisms of gas desorption and diffusion in coal due to either methane drainage and/or mining of the coalbed reservoir.

Reservoir simulators can be used to perform a variety of analyses. The primary applications relative to coalbed methane/mining are:

- Determining the volume of gas-in-place
- Developing optimum methane drainage systems to reduce the flow of gas into underground mine workings
- Predicting the methane emission consequences of changing mining methods and practices

- Identifying and diagnosing production problems in operating methane drainage systems
- Predicting gas recovery from methane drainage systems associated with underground mines

In general, three different types of coalbed methane reservoir simulators are available: gas sorption and diffusion simulators, compositional simulators, and black oil simulators. The compositional simulators with coalbed methane options that can handle the sorption and diffusion processes are widely used and are more appropriate for coalbed methane applications due to their capability for simulating different gas mixtures.

Reservoir simulators for coalbed methane applications are also classified based on their treatment of the gas sorption process. More than 50 coalbed methane reservoir simulators are described in the literature [King and Ertekin 1989a,b; 1991], which are classified as equilibrium sorption (pressure-dependent) and nonequilibrium sorption (time- and pressure-dependent) simulators. The basic difference between these two classifications is that when using equilibrium simulators, it is implicitly assumed that as the pressure declines, the gas immediately enters the fracture system. This oversimplification gives optimistic gas flow rates in some cases. Nonequilibrium models, which take the sorption time into account and include modifications to the conventional dual-porosity models, are more realistic. The primary modifications required to enhance the simulation capability of the dual-porosity models are to account for methane storage by adsorption on the matrix-coal surface and control of gas transport through the coal matrix by diffusion until the gas reaches the fracture network, where conventional Darcy flow mechanics are the controlling transport factor.

The most realistic simulations of gas flows in coalbeds are provided by compositional, nonequilibrium, dual-porosity reservoir models. These models account for sorption time, methane storage by adsorption, and gas transport by diffusion through the coal matrix to the fracture network.

Although numerical reservoir simulation techniques offer more reliable emission predictions and guidance for optimum methane drainage system designs, building objective-oriented models requires more time and effort for gathering site-specific data, careful analysis of field data, and detailed planning.

The basic steps of performing a gas flow/production study using a reservoir simulator are as follows [Saulsberry et al. 1996]:

- State the study objectives
- Select a reservoir simulator
- Collect and evaluate all geologic and engineering data
- Construct a geologic model for reservoir
- Design the simulation grid
- Digitize the maps
- Install engineering data into the model
- Define the well operating constraints
- Perform simulations

Reservoir models require a substantial amount of site-specific data to provide reliable simulations of gas flow and production from boreholes/wells. Commonly, all of the reservoir property data required to conduct a simulation are not available or are unknown. This is particularly true in the mining industry where reservoir modeling is relatively new and coalbed reservoir property base data acquisition is not part of the routine site evaluations. However, as more mines are considering the commercial production of coalbed methane, the value of obtaining coalbed reservoir data is becoming more widely recognized. It is an accepted reservoir engineering practice to use measured gas production data from boreholes and wells in "history matching" exercises to estimate some of the unknown reservoir properties. For mining-related applications, gas production data from both vertical and horizontal methane drainage boreholes and gob gas ventholes can be used for history matching. Because of the potential for gas production variabilities due to non-reservoir-related reasons (such as mechanical problems with pumps, etc.), using multiwell data sets for history matching is usually more dependable than single-well simulations, and they provide a better representation of the reservoir.

Although reservoir simulators are very successful in the representation of the multiphase flow and time-dependent gas diffusion processes in coalbeds, they do not readily model the dynamics of the mining process on the coalbed reservoir and surrounding strata. The progressive advance of the mine face and associated removal of the coalbed reservoir is a key dynamic that must be accounted for in mining-related simulations and can be accomplished with "frequent restart" files representing periodic updates of the reservoir geometry consistent with expansion of the mine.

Another aspect of longwall mining that cannot be predicted by conventional reservoir simulators is the geomechanical response in the surrounding strata, causing permeability changes that influence the drainage of gob gas. This problem can be manually overcome by computing the changes in rock properties (in particular, permeability) with a geomechanical program such as FLAC[4] [Itasca Consulting Group 2000] and representing those reservoir property changes in the appropriate reservoir simulation steps. Karacan et al. [2005] discuss how these dynamic mining-related processes can be addressed in a longwall mining simulation to optimize gob gas venthole methane drainage.

Other alternatives to reservoir simulation to predict gas emissions due to mining are "Roofgas" and "Floorgas" programs specifically designed for mining applications. They produce graphical representations of strata relaxation and gas flow using boundary-element and bed separation techniques to calculate the strata response and the rate of gas release [Lunarzewski 1998].

Numerical analysis and modeling techniques are the most powerful tools available to simulate gas flows and emissions in the mining environment. However, the successful application of these methods is highly dependent on the availability of valid, site-specific, reservoir property data.

[4]Fast Lagrangian Analysis of Continua.

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