Coalbed-Methane Reservoir Simulation: An Evolving Science

Correctly determining what to model in a coalbed-methane (CBM) reservoir simulation is almost as daunting a task as the simulation work itself. The full-length paper discusses how the exploitation and development of coalbed resources throughout the world are changing and how CBM reservoir simulation is changing as well.

This article, written by Assistant Technology Editor Karen Bybee, contains highlights of paper SPE 84424, "Coalbed-Methane Reservoir Simulation: An Evolving Science," by ***T.L. Hower,*** *SPE, Malkewicz Hueni Assocs. Inc., prepared for the 2003 SPE Annual Technical Conference and Exhibition, Denver, 5–8 October.*

Introduction

Any conventional black-oil simulator can be used to simulate a CBM reservoir. The idea of modifying a conventional black-oil model to simulate the performance of CBM wells was first presented by Amoco in 1990. First, the model is initialized with a small immobile oil saturation. Oil-saturation magnitude is not important, but it is important that the oil be immobile and that the flow of the other fluids not be affected. Pore volume is adjusted to maintain the proper initial fluid volumes, and the fluid saturations are shifted to maintain the original relative permeability relationships. The last change is to supply a relationship for dissolved gas as a function of pressure that will mimic the gas-content isotherm that would normally be used to describe a CBM system. In essence, the gas dissolved in the oil replaces the Langmuir-isotherm function. The modified black-oil representation works well if the release of gas from the matrix to the cleats is fast compared to the flow of gas and water in the cleats because the modified black-oil technique implicitly assumes that the sorption time is instantaneous. Problems can occur if the actual sorption time in the coals is unusually long, or if the permeability of the cleat system is extremely high.

Fig. 1 shows a comparison of results from a modified black-oil model and a specialized CBM reservoir-simulation model for a single-well case study of a coal seam in the Lorraine basin in France. Assumptions made included that coal permeability was approximately 3 md, cleat porosity was 1%, the well was hydraulically fractured, and the coal was 30% undersaturated at initial conditions with a 325-scf/ton gas content. Even for a sorption time of 720 hours, the modified black-oil model duplicates the results from the specialized CBM model for most of the well's producing life.

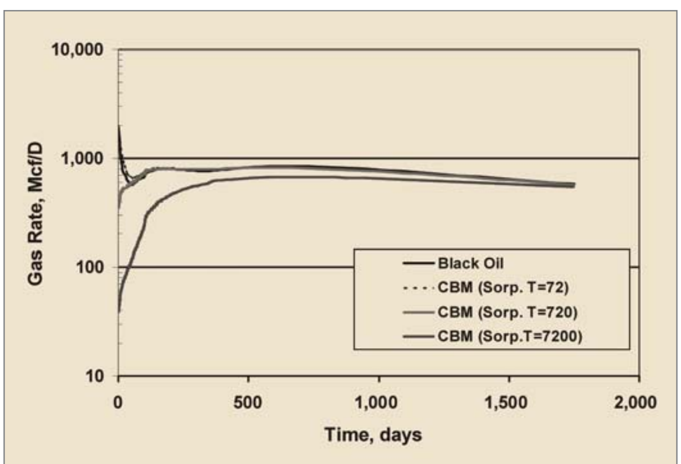

Fig. 1—Comparison of modified black-oil model and a CBM simulator.

As the worldwide exploitation and development of CBM has grown over the past 15 years, so too has the complexity of the problems. Deciding whether to use a modified black-oil model or a CBM simulation model is only the beginning

Coals and Sands

The easiest way to describe a CBM simulator is to think of a conventional reservoir simulator in a dual-porosity mode. Usually a conventional dual-porosity simulator is used to model a system such as a fractured carbonate reservoir where there is a low-permeability matrix coupled to a high-permeability fracture network. Each system has its own unique permeability and porosity, and a matrix/fracture transfer term governs the fluid flow from the matrix into the fractures.

In a CBM model, the fracture network represents the coal cleats. However, the matrix portion of the system has no effective permeability and porosity and is used only as a gas source with gas release controlled by a gas-content vs. pressure relationship supplied as input data. While it is common to refer to CBM models as dual-porosity models, they are really only single-porosity models with a pressure-dependent source term coupled to the reservoir.

If the system modeled is entirely coal, the simulation approach is straightforward. Coal properties must be supplied as input data as well as system permeability, porosity, initial pressure, and initial fluid saturations. As water is removed from the cleat system, the reservoir pressure declines, gas is desorbed from the coal into the cleats, and gas production begins. This approach has been used successfully over the years in models representing simple single-well systems as well as larger, more-complex models containing thousands of producing CBM wells.

One complexity that can arise in setting up a CBM simulation is if there is a mixture of coals and sands, with both reservoirs contributing to gas production. In this case, gas depletion from the conventional reservoir as well as desorption of gas from the coal into the cleats must be represented accurately. The coal layers in the model are treated in the same way as if the system were entirely coal; a Langmuir isotherm describes the desorption process, and the porosity, permeability, and relative permeability control fluid flow in the cleats. The sand layers in the model are treated in the same way, except the Langmuir isotherm supplied for the sands has zero gas content. The fracture component of the sand layers is assigned rock properties consistent with the sand characteristics.

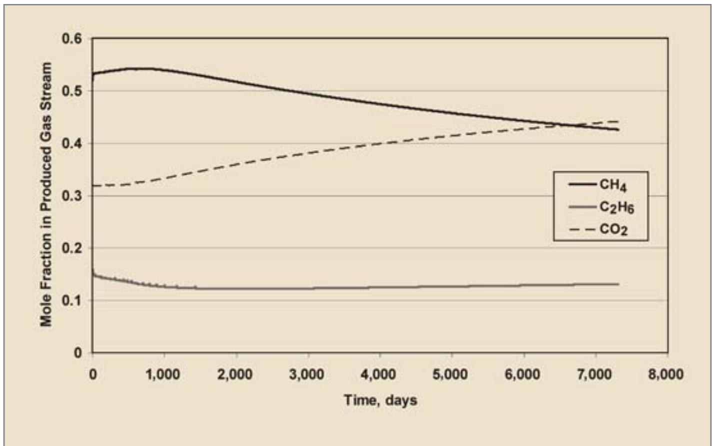

Fig. 2—Produced-gas composition predicted by a compositional CBM model.

Multicomponent Gases

Enhanced CBM recovery involves the injection of carbon dioxide (CO_2) or nitrogen into the coal to enhance methane production. CO_2 becomes preferentially adsorbed onto the coal, displacing methane. Nitrogen flushes the methane from the coal by reducing the methane partial pressure to zero. In either case, a compositional model is required to track the individual components and to account properly for the adsorption/desorption of the different components on/from the coal surface.

Besides being the deepest commercial coal play in the world, the White River Dome field also is unique because it produces a three-component gas: methane (CH_4), ethane (C_2H_6), and CO_2. The coal has a greater affinity for CO_2 at any pressure. Also, the desorption of significant CO_2 volumes does not occur until low pressures. This is why the CO_2 content in gas produced from many CBM reservoirs increases late in field life. Compositional CBM models require the initial adsorbed-gas composition and individual-component isotherm relationships as input data. **Fig. 2** shows the change in gas composition predicted by the compositional CBM model over the life of this well. The methane is preferentially depleted first, while the percentage of CO_2 produced increases in late life. The amount of ethane remains relatively constant during the producing life of the well. Compositional CBM models predict the total produced gas stream and track the individual components in the gas as well. Not all commercially available reservoir-simulation models can model three or more components in the gas stream. The results presented in the full-length paper were generated by a compositional CBM reservoir simulator developed at Pennsylvania State U.

Besides tracking the individual components in a multicomponent gas stream, the second most critical requirement for a CBM simulator is the ability to model the shrinking and swelling of the coal matrix. Nearly all available simulation models provide the ability to enter a relationship for variations in porosity and permeability as a function of pressure (stress). For most standard CBM applications, this capability is sufficient to model the expected changes in the cleat system as reservoir pressure declines and the coal matrix shrinks because of gas desorption. However, recent research indicates that the shrinking and swelling is magnified and significantly more complex when CO_2 is present in the gas. Thus, for multicomponent CBM systems, more-specialized simulation models may be required to address these factors.

Horizontal and Multilateral Wells

More-sophisticated drilling and completion techniques were developed as tighter and thinner coal seams were targeted for exploitation. While the challenge for the CBM simulation engineer used to be properly characterizing a hydraulic fracture or a region of cavitation around a wellbore, now one is faced with incorporating irregular well trajectories that may extend for thousands of feet and a well path that can exit and re-enter the coal several times. In some cases, given all the other uncertainties inherent in the evaluation of CBM reservoirs, it is not necessary to describe the well path down to the last foot of its trajectory.

However, in numerous cases, a rigorous description of the CBM-well trajectory is required for proper simulation. **Fig. 3** shows the reservoir-pressure trends for a multilateral CBM well drilled in Queensland, Australia. Fig. 3 illustrates the predicted areas of pressure depletion at a given point in time. Approximately 400 m at the end of the top lateral had collapsed. With this portion of the upper lateral effectively shut in, the pressure distribution is asymmetric. The complex grid was extended to include the collapsed portion so the benefits of re-entering the well and extending the lateral can be simulated and evaluated. With the sophisticated software tools available today, grids similar to the one shown in Fig. 3 can be created in minutes and imbedded into a standard Cartesian grid system. Because simulation run times will increase because of the increased grid complexity, each situation should be evaluated to determine whether a simple Cartesian simulation is sufficient or a more sophisticated approach is required.

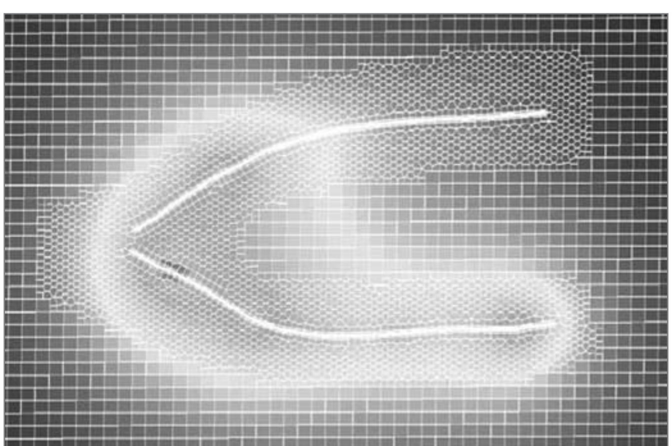
Fig. 3—Hexagonal grid imbedded in a Cartesian grid to simulate a multilateral well.

Coalbed and Coal-Mine Methane

Mining operations in a worked coal seam create large regions of fractured and destressed coals above and below the mined seam. The gas resources associated with these destressed coal seams have been recovered by use of large-diameter, low-pressure (suction) vent wells.

Traditionally, coal-mine-methane production was modeled by use of specialized 3D simulation tools. Recently, conventional CBM reservoir simulators have been used to evaluate coal-mine-methane projects. Construction of a coal-mine-methane model involves developing a combined areal model to represent the multiple coal seams in the area of interest, including both the high-permeability fractured (destressed) region and the outlying (stressed) coals that desorb gas and contribute to methane production. Once the model is constructed, the reservoir must be coupled, and the permeability, gas-content relationships, and initial pressure of the various parts of the system must be described accurately.

Coal-mine-methane simulation involves a few unique challenges including the following.

- The residual gas content of the coal seams and its spatial distribution throughout the abandoned mine must be determined.
- The historic mining activities and the effect of those activities on the permeability of the seams surrounding the mine must be evaluated.
- Estimates of water level in the mine and changes in water level during vent-well production must be made because submerged seams cannot desorb methane.
- Variations in the percent of methane in the produced gas over time because of ingress of air into the mine must be estimated.

Typically, coal-mine-methane projects are commercialized with a target gas-supply plateau rate in mind. Facilities are designed to meet that plateau, or contract gas rate for a certain period of time. Simulations can provide a graph of total projected vent gas flow rate vs. cumulative gas production.

Single, Dual, or Triple Porosity

A recent paper discussed the development of a specialized CBM model that included a triple-porosity reservoir system. The model includes a porosity system within the coal matrix blocks to provide storage for additional free gas and water. The net effect is to slow the gas-movement process from desorption from the coal micropores into the coal cleat network by introducing this intermediate-porosity system. It is argued that in certain cases, the lower gas and higher water production rates generated by the triple-porosity model are more consistent with observed field performance. JPT

For a limited time, the full-length paper is available free to SPE members at www.spe.org/jpt. The paper has not been peer reviewed.