Fekete has been providing well test services to the oil & gas industry since 1973. These services initially included test design, procurement of test equipment/ personnel, test supervision and test analysis. In the late 1980’s Fekete began developing software to alleviate some of the laborious tasks associated with well test analysis, so the analyst could focus more attention on the interpretation of the test data. As computer technology rapidly advanced throughout the 1980’s and 1990’s, so too did the software technology, which had a significant impact on the quality of the test interpretations. Not surprisingly, many of Fekete’s clients expressed interest in acquiring the software to assist in their own test interpretations. This launched Fekete into commercial software development in the early 90’s.

Over the years, the well test group has analyzed in the order of 1000 tests a year (in excess of 30,000 tests to date!). The vast knowledge gained from this experience is evident from the workflow and user friendliness of the software today. In addition to providing the aforementioned well test services, the well test group provides the front line support for the well test software. Therefore, when a user calls for support, they actually speak to an experienced well test analyst.

The vast experience of Fekete’s well test services group is evident from the workflow and user friendliness of the software today.

With the dramatic increase in commodity prices over the last few years, optimizing production and assessing deliverability potential has become more critical to the bottom line of producers. Consequently, the demand for quality well test software and services has increased substantially. To this end, we have reorganized and expanded the well test group to serve these needs.
Practical Considerations for CBM Field Development

The most common question we are asked is how many wells do I need to develop my CBM field. The question arises not only for new developments but also in producing fields where infill drilling continues to yield incremental reserves and the optimal well spacing has not yet been determined after years of production.

There are numerous articles in the literature focusing on the early-life behavior of CBM production with its unique increasing production profile (negative decline). We find however that many of these studies focus on single well behavior. If the argument can be made that single well production profiling (i.e. decline analysis) is insufficient to evaluate infill drilling of conventional gas, the need for an alternative, even more evident in CBM due to the dewatering effect.

This article walks through our experience in weighing the practical considerations, and undertaking the necessary calculations, to understand the optimal CBM field development strategy. We preface our comments by saying we take the practical approach to reservoir modeling. We discuss first the virtues and limitations of analytical modeling, and then the situations when numerical modeling of CBM is ultimately justified and needed.

Depending on the shape of the Langmuir isotherm, CBM production may exhibit late-life hyperbolic decline with significant reservoirs performed at very low pressures. Compression and pipeline costs, necessary to flow the gas at low pressures, are the key economic driver. However, each additional compressor must be justified on an incremental economic basis which leads us back to the question of well density. To fill the compressor, a concurrent incremental economic basis which leads us back to the question of well density.

In very high permeability reservoirs, two effects are noticed. First, if the reservoir is in the early dewatering period (prior to any gas production), then additional ring-fence wells may be required in order to remove water fast enough to drop reservoir pressure below the desorption pressure. Admittedly this can be a leap of faith and can make certain companies hesitant or nervous until they see the start of gas production. Second, if the reservoir is already dewatered, then infill drilling is purely production acceleration (identical to a high permeability conventional gas reservoir).

For a truly complicated by the dewatering effect. Infill drilling accelerates dewatering resulting in lower reservoir pressure on both the infill and pre-existing wells. This sometimes causes the existing well to experience a surge in production rate as a result of the infill well. This is truly a win-win situation in the short term. Over the longer term, it must be remembered that the economics has been drastically changed by the infill well. A combined production forecast of the existing and infill well must be simulated to determine if the net gas recovery is incremental.

Our approach is to areally segregate a field into low, medium and high permeability areas. Low permeability areas are modeled on a well by well basis. Medium permeability areas are modeled on a localized (i.e. square mile) basis by incorporating individual well productivity indices and evaluating the material balance as a tank model (i.e. no transient effects) on all wells within the area. High permeability areas are modeled as one tank regardless of area extent.

The limitation of this methodology is that gas flow across these artificially defined areas is not accounted for. Nonetheless, the assumption is reasonable when one realizes that the same issue persists if a full-field simulation were attempted. CBM reservoirs are rarely edge bound as the coal seams can extend over even greater distances. As a result, we are not dealing with a closed system and attempts on a field-wide material balance are prone to being pessimistic.

Matrix shrinkage is a known phenomenon. Several models are developed for describing its effect on coal absolute permeability but lack of experimental data to support the models is a common shortcoming in their application. Periodic build-up testing on the same well may illustrate the matrix shrinkage phenomenon. The resulting effective permeabilities from the tests are corrected for relative permeability to calculate absolute permeability. If the change in absolute permeability due to matrix shrinkage is significant, the need for infill drilling is reduced.

Finally, and most importantly from an economic perspective, is the multi-component isotherm. Given the nature of the Langmuir isotherms, much of the CH4 is desorbed at low pressures. This effect is even stronger for CO2 desorption due to higher affinity of coal to CO2.

As reservoir average pressure further declines, the CO2 fraction in desorbed gas will rise from virtually none to reported cases as high as 20%. Decisions on late-life compressor installations and recompletion of existing wells depend on gas composition but whether the CO2 percentage will be too high such that the gas will not meet sales gas specifications for heating value. The challenge is that existing wells has been altered by dewatering phenomenon and the CO2 cannot be overstated as these parameters are vital in the calculation of gas composition in a coalbed reservoir simulation.

The same effect is also present in ECBM applications where CO2 and/or N2 or a mixture of both is injected into coal seams to enhance the production of methane either by displacement or by sweeping mechanisms. While N2 injection results in a faster hike in methane production, CO2 leads to a longer lasting effect. In Figure 2, the result may vary in different locations due to high non-methane fractions over production time. The declining fraction of CH4 and the rising fraction of CO2 against increasing recoverable gas are depicted in Figure 1. Typically when the fraction of CH4 falls below 95%, the heating value of gas drops to less than marketable pipeline values. The produced gas, therefore, should be spiked or blended with a higher heating value gas and the added cost must be considered in the economics. An example of such a case is illustrated in Figure 2. Using typical coal seam properties and assuming a drainage area of 160 acres and initial in-situ adsorbed CO2 fraction of 10%, it is shown that CO2 fraction in produced gas is attained at a gas recovery of 50%. As a result, the produced gas beyond 50% recovery point needs to be spiked or blended.

After evaluating the individual well and reservoir parameters in F.A.S.T. CBM™, the results are linked to Fekete’s F.A.S.T. Piper™ software which models the gas gathering system and permits evaluation of multiple drilling/compression scenarios. The software accounts for binary component isotherms and generates both a production and compositional forecast.

Our approach using the F.A.S.T. CBM™ and F.A.S.T. Piper™ analytical software takes a practical approach that stresses understanding the reservoir characteristics and making engineering judgments in a methodical evaluation process. Ultimately, there are trade-offs for utilizing the faster analytical method. Numerical simulation remains an option when good data quality is available, when reservoir boundary effects need to be modeled or when transient pressure and interference effects need to be understood.

Conclusion

Determining the drilling schedule and ultimate density is key to maximizing return on capital and minimizing surface impact. Fekete’s F.A.S.T. Piper™ software provides a real-time feedback on the CBM development and trends toward future development opportunities. Linking F.A.S.T. Piper™ to Fekete’s F.A.S.T. CBM™ analytical reservoir simulator provides real world solutions to both pipeline and reservoir interference effects. Understanding the ultimate drilling density will permit long-term planning and minimize environmental impact.

For fair to good permeability, the evaluation of CBM reservoirs is further complicated by the dewatering effect. Infill drilling accelerates dewatering resulting in lower reservoir pressure on both the infill and pre-existing wells. This sometimes causes the existing well to experience a surge in production rate as a result of the infill well. This is truly a win-win situation in the short term. Over the longer term, it must be remembered that the economics has been drastically changed by the infill well. A combined production forecast of the existing and infill well must be simulated to determine if the net gas recovery is incremental.

Three other considerations are then layered onto the analysis: structure, matrix shrinkage and multi-component isotherms.

Structure plays a role in higher permeability reservoirs. Dewatering wells are best placed downip in order to lower the water table as much as possible. Conversely, production wells placed at the top of the structure will see the earliest onset of gas production. Structural placement of infill wells, with respect to the current water table, will significantly vary the production results.

As reservoir average pressure further declines, the CO2 fraction in desorbed gas will rise from virtually none to reported cases as high as 20%. Decisions on late-life compressor installations and recompletion of existing wells depend on gas composition but whether the CO2 percentage will be too high such that the gas will not meet sales gas specifications for heating value. The challenge is that existing wells has been altered by dewatering phenomenon and the CO2 cannot be overstated as these parameters are vital in the calculation of gas composition in a coalbed reservoir simulation.

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Figure 1 Typical simulated CH4 and CO2 mole fraction profiles.

Figure 2 Relationship between CO2 fraction, cumulative gas production and average reservoir pressure.
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The most common question we are asked is how many wells do I need to develop a field. The question arises not only for new developments but also in producing fields where infill drilling continues to yield incremental reserves and the optimal well spacing has not yet been determined after years of production.

There are numerous articles in the literature focusing on the early-life behavior of CBM production with its unique increasing-production profile (negative decline). We find however that many of these studies focus on single well behavior. If the argument can be made that single well production profiling (i.e. decline analysis) is insufficient to evaluate infill drilling of conventional gas, the need for an alternative approach is even more evident in CBM due to the dewatering effect.

This article walks through our experience in weighing the practical considerations, and undertaking the necessary calculations, to understand the optimal CBM field development strategy. We preface our comments by saying we take the practical approach to reservoir modeling. We discuss first the virtues and limitations of analytical modeling, and then the situations when numerical modeling of CBM is ultimately needed and justified.

Depending on the shape of the Langmuir isotherm, CBM production may exhibit late-life hyperbolic decline with significant reservoir water produced at very low pressures. Compression and pipeline costs, necessary to flow the gas at low pressure, may become the key economic driver. However, each additional compressor must be justified on an incremental economic basis which leads us back to the question of well density. To fill the compressor, a concurrent incremental economic basis which leads us back to the alternative approach is even more evident in CBM due to the low pressures, then become the key economic driver. However, increasing-production profile (negative decline). We find that many of these studies focus on single well behavior. If the argument can be made that single well production profiling (i.e. decline analysis) is insufficient to evaluate infill drilling of conventional gas, the need for an alternative approach is even more evident in CBM due to the dewatering effect.

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Matrix shrinkage is a known phenomenon. Several models are developed for describing its effect on coal absolute permeability but lack of experimental data to support the models is a common shortcoming in their application. Periodic build-up testing on the same well may illustrate the matrix shrinkage phenomenon. The resulting effective permeabilities from the tests are corrected for relative permeability to calculate absolute permeability. If the change in absolute permeability due to matrix shrinkage is significant, the need for infill drilling is reduced.

Finally, and most importantly from an economic perspective, is the multi-component isotherm. Given the nature of the Langmuir isotherms, much of the CH₄ is desorbed at low pressures. This effect is even stronger for CO₂ desorption due to higher affinity of coal to CO₂.

Three other considerations are then layered onto the analysis:
1. Structure, matrix shrinkage and multi-component isotherms.
2. As reservoir average pressure further declines, the CO₂ fraction in desorbed gas will rise from virtually none to reported cases as high as 26%. Decisions on late-life compressor installations and production rates are impacted by this fact, but whether the CO₂ percentage will be too high such that the gas will not meet sales gas specifications for heating value. The degradation of the existing wells has been largely limited to the water gas production. Structural placement of infill wells, with respect to the current water table, will significantly vary the production results.

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The same effect is also present in ECBM applications where CO₂ and/or N₂ are mixed into coal seams to enhance the production of methane either by displacement or by sweeping mechanisms. While N₂ injection results in a faster hike in methane production, CO₂ leads to a longer lasting effect that is the result in different profiles of non-methane fractions over production time. The declining fraction of CH₄ and the rising fraction of CO₂ against increasing recoverable gas are depicted in Figure 1. Typically when the CH₄ fraction of CO₂ falls below 95%, the heating value of gas drops to less than marketable pipeline values. The produced gas, therefore, should be spiked or blended with a higher heating value gas and the added cost must be considered in the economics. An example of one such case is illustrated in Figure 2. Using typical coal seam properties and assuming a drainage area of 160 acres and initial in-situ adsorbed CO₂ fraction of 18%, it is shown that 5% CO₂ fraction in produced gas is attained at a gas recovery of 50%. As a result, the produced gas beyond 50% recovery point needs to be spiked or blended.

After evaluating the individual well and reservoir parameters in F.A.S.T. CBM™, the results are linked to Fekete’s F.A.S.T. Piper™ software which models the gas gathering system and permits evaluation of multiple drilling/compression scenarios. The software accounts for binary component isotherms and generates both a production and compositional forecast.

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Conclusion

Determining the drilling schedule and ultimate density is key to maximizing return on capital and minimizing surface impact. Fekete’s F.A.S.T. Piper™ software provides a real-time field development and management tool to run future development and production scenarios. Linking F.A.S.T. Piper™ to Fekete’s F.A.S.T. CBM™ analytical reservoir simulator provides real world solutions to both pipeline and reservoir interference effects. Understanding the ultimate drilling density will permit long-term planning and minimize environmental impact.
What’s News at Fekete

Fekete at SPE Conference in Dallas

Fekete at SPE Conference in Dallas
We want to see you! Please come visit us at the SPE Annual Technical Conference in Dallas, October 9 – 12, 2005.

Experts in well testing, CBM, pipeline optimization, rate-transient analysis and acid gas will be on-hand including those you have seen in our technical videos, Louis Mattar, Dave Anderson and Ralph McNeil.

We’ll have a large screen set up for group software presentations and discussion but our technical support goes beyond just software use. You’re welcome to bring along any data and our technical staff will be more than happy to review it with you.

We always look forward to these opportunities to visit both personally and professionally. Our booth is #1963, located near the center of the exhibition hall.

Pick Up Video 7 SPE ATCE Dallas

Receive the 7th video in our Technical Video Series before it’s distributed to the public in December 2005. Pick-up your copy at booth #1963 at the SPE ATCE in Dallas.

In Video # 7, Ralph McNeil presents, “Gas Reserves Determination — Use Basic Classical Techniques to Reduce Uncertainty.” This presentation demonstrates how reserve determination should be based on combinations of methods. Since each method has certain advantages and limitations, combinations of the methods will reduce uncertainty in the reserve estimates and will also increase understanding of the reservoir drive mechanism and the potential for further recovery.

The presentation begins with a brief introduction to the methods highlighting their advantages and limitations: Volumetric, Traditional Decline, Material Balance, Advanced Decline (Rate Transient Analysis) and Simulation. It then presents four case studies highlighting how combinations of volumetric, decline and material balance can improve the certainty of the reserve assignments and provide a means for identification of additional potential.

Ralph McNeil, PIng., is a Senior Technical Advisor at Fekete Associates Inc. He has over 24 years of petroleum engineering experience, specializing in reservoir engineering and gas gathering system optimization.

Fekete’s Well Test Services

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Reza Ali, a senior reservoir advisor with 18 years industry experience (the last 10 years at Fekete), has assumed the responsibility of managing the well test group, which now consists of 10 reservoir analysts.

Marty Santos, the previous manager and technical lead of the well test group (with 29 years of well test experience), will play a larger role in technical training, development of the well test software, in addition to providing technical support to the well test group.

Frank Brunner, with 25 years of well test experience, has recently joined the well test group as a senior technical advisor. For the last 15 years, Frank was responsible for all the domestic well testing requirements at Encor/Talmann Energy, in addition to assisting on a number of challenging international projects.

Louis Mattar, who is renowned for his technical expertise in well testing, will continue to provide technical support to the well test group and software development, and teach well test interpretation, nationally and internationally.

From Left to right: Frank B., Louis M., Marty S., Reza A.