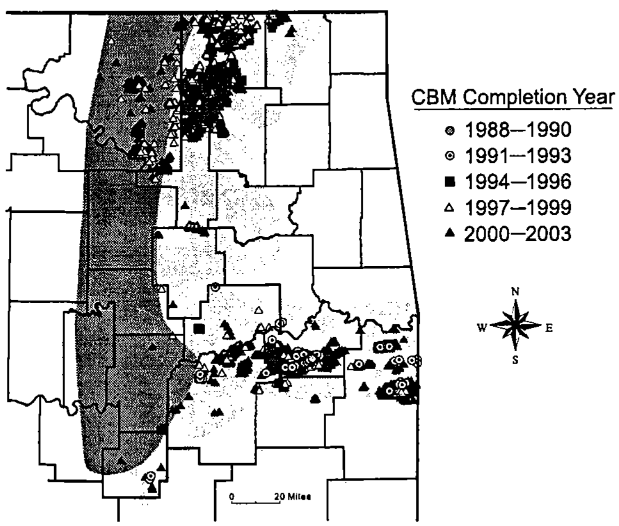
Oklahoma Geological Survey
Charles J. Mankin, *Director*

Circular 110
ISSN 0078-4397

Unconventional Energy Resources in the Southern Midcontinent, 2004 Symposium

BRIAN J. CARDOTT, *Editor*



Proceedings of a symposium held March 9–10, 2004, in Oklahoma City, Oklahoma.

Co-sponsored by:
Oklahoma Geological Survey
and
National Petroleum Technology Office,
U.S. Department of Energy

The University of Oklahoma
Norman

2005

OKLAHOMA GEOLOGICAL SURVEY

CHARLES J. MANKIN, *Director*

SURVEY STAFF

JAMES H. ANDERSON, *Manager of Cartography*
RICHARD D. ANDREWS, *Geologist IV*
BETTY D. BELLIS, *Staff Assistant III*
MITZI G. BLACKMON, *Staff Assistant II*
DAN T. BOYD, *Geologist III*
RAYMON L. BROWN, *Geophysicist III*
BRIAN J. CARDOTT, *Geologist IV*
JAMES R. CHAPLIN, *Geologist IV*
JANISE L. COLEMAN, *Staff Assistant II*
CHRISTIE L. COOPER, *Manager of Publications*
TAMMIE K. CREEL-WILLIAMS, *Staff Assistant III*
SUE B. CRITES, *Public Relations Coordinator*
CHARLES R. DYER III, *Equipment Operations Maintenance Person IV*
ROBERT O. FAY, *Geologist IV*
AMIE R. FRIEND, *Research Tech III*
JAMES W. KING, *Research Tech IV*
STANLEY T. KRUKOWSKI, *Geologist III*
EUGENE V. KULLMANN, *X-Ray/Imaging Technician*
JAMES E. LAWSON, JR., *Chief Geophysicist*
LAURIE A. LOLLIS, *Cartographic Technician II*
KENNETH V. LUZA, *Geologist IV*
MICHAEL J. MERCER, *Manager, Log Library*
GALEN W. MILLER, *Research Associate*
RICHARD G. MURRAY, *Copy Center Operator*
SUE M. PALMER, *Staff Assistant I*
DAVID O. PENNINGTON, *Facilities Attendant II*
RUTH E. RECLA, *Assistant to the Director*
CONNIE G. SMITH, *Promotion and Information Specialist*
PAUL E. SMITH, *Supervisor, Offset Press Copy Center*
G. RUSSELL STANDRIDGE, *Information Tech Analyst I*
THOMAS M. STANLEY, *Geologist III*
LLOYD N. START, *Equipment Operations Maintenance Person III*
JOYCE A. STIEHLER, *Staff Assistant II*
MICHELLE J. SUMMERS, *Technical Project Coordinator*
NEIL H. SUNESON, *Assistant Director, Geological Programs*
JANE L. WEBER, *Publication and Database Coordinator*

Cover Picture

Map of Oklahoma coalfield showing coalbed-methane well completions in Oklahoma by year (from Fig. 2, p. 70, this volume).

This publication, printed by the Oklahoma Geological Survey, is issued by the Oklahoma Geological Survey as authorized by Title 70, Oklahoma Statutes, 1981, Sections 231–238. 1,050 copies have been prepared for distribution at a cost of $6,650 to the taxpayers of the State of Oklahoma. Copies have been deposited with the Publications Clearinghouse of the Oklahoma Department of Libraries.

PREFACE

Unconventional energy resources (coalbed methane, shale gas, tight gas) are considered the next energy frontier. Of importance to these resources has been the development of completion technology to economically recover gas from low permeability coals, shales, and sandstones. Petroleum exploration and development decisions are made based on technical information and data. To facilitate this technology transfer, the Oklahoma Geological Survey (OGS) and the U.S. Department of Energy, National Energy Technology Laboratory (DOE–NETL), in Tulsa, cosponsored a symposium dealing with successful practices for developing unconventional energy resources in the southern Midcontinent. The symposium was held on March 9–10, 2004, in Oklahoma City, Oklahoma. This volume contains the proceedings of that symposium.

Research reported upon at the symposium focused on case histories, best practices, characterization, development, resources, and potential of unconventional energy reservoirs in the southern Midcontinent. We hope that the symposium and these proceedings will bring such research to the attention of the geoscience and energy-research community, and will help foster exchange of information and increased research interest by industry, academic, and government workers.

Eleven talks and one poster presented at the symposium are printed here as full papers or extended abstracts. An additional seven talks and one poster are presented as abstracts. About 345 persons attended the symposium. Stratigraphic nomenclature and age determinations used by the various authors in this volume do not necessarily agree with those of the OGS.

This is the sixteenth symposium dealing with topics of major interest to geologists and others involved in petroleum-resource development in Oklahoma and adjacent states. These symposia are intended to foster the exchange of information that will improve our ability to find and recover our Nation's oil and gas resources. Earlier symposia covered: Anadarko Basin (published as OGS Circular 90); Late Cambrian–Ordovician Geology (OGS Circular 92); Source Rocks (OGS Circular 93); Petroleum-Reservoir Geology (OGS Circular 95); Structural Styles (OGS Circular 97); Fluvial-Dominated Deltaic Reservoirs (OGS Circular 98); Simpson and Viola Groups (OGS Circular 99); Ames Structure in Northwest Oklahoma and Similar Features—Origin and Petroleum Production (OGS Circular 100); Platform Carbonates (OGS Circular 101); Marine Clastics (OGS Circular 103); Pennsylvanian and Permian Geology and Petroleum (OGS Circular 104); Silurian, Devonian, and Mississippian Geology and Petroleum (OGS Circular 105); Petroleum Systems of Sedimentary Basins (OGS Circular 106); Revisiting Old and Assessing New Petroleum Plays (OGS Circular 107); and Finding and Producing Cherokee Reservoirs (OGS Circular 108).

Persons involved in the organization and planning of this symposium include: Brian Cardott and Charles Mankin of the OGS and Bill Lawson of DOE–NETL. Other OGS personnel who contributed include Michelle Summers, meeting coordinator; Tammie Creel, registration chair; and Connie Smith, publicity chair. Appreciation is expressed to each of them and to the many authors who worked toward a highly successful symposium. Special thanks is extended to Christie Cooper, OGS manager of publications, to Thomas W. Henry (Westminster, Colorado) for technical editing of this volume, and to Sandra Rush (Denver, Colorado) for layout and production.

BRIAN J. CARDOTT
General Chairman

CONTENTS

Targeted Reservoir Characterization of Unconventional Gas: Tight Sand, Coalbed Methane, Deep Gas, and Fractured Gas Shale

Carrie Decker
Veritas Exploration Services
Houston, Texas

ABSTRACT.—Many unconventional gas reservoirs of the Midcontinent, including coalbed methane, ultra-deep gas, fractured gas shales, and tight sands, can be structurally and/or stratigraphically complex, and adequate characterization of their heterogeneity requires application of targeted reservoir characterization workflows. Optimal production of each of these resources requires a clear picture of its heterogeneity, such as discontinuities and/or compartmentalization, changes in matrix and fracture porosity, reservoir thickness, and fluid content. Conventional reservoir-characterization workflows may not be appropriate for complex unconventional fields. The correct approach is a tailored workflow that targets the problem specific to the reservoir type and that makes use of cutting-edge technologies to deliver the most information about the subsurface, particularly those that use existing data in order to be cost-effective.

Each unconventional gas-reservoir type has a specific measurable or interpretable attribute or set of attributes that most influences reservoir performance (e.g., porosity or fracture distribution in a tight sand). Thus, the first objective of successful characterization of an unconventional gas resource is to identify and rank the dominant attributes for that particular reservoir. The next step is to design a workflow that incorporates the appropriate technology to quantify changes in the attribute(s) at a suitable scale, ultimately leading to an accurate geological model, realistic simulation, optimal new well site prediction, and apt completion or stimulation recommendations. The complexity of the reservoir dictates the scale at which the key reservoir properties must be described.

Quantification of reservoir attributes in the subsurface at sufficiently high resolution vertically and laterally depends on integration of well and seismic data. Application of appropriate cutting-edge technology, such as Instantaneous Spectral Analysis, a spectral decomposition technology, can add value to seismic data as reservoir-characterization input. Spectral decomposition is emerging as a key prospecting tool; it has been applied successfully in conventional gas reservoirs to detect hydrocarbons. However, because it uses a wavelet-transform algorithm to maximize resolution vertically and laterally as well as in the frequency domain, it also delivers useful information about reservoir discontinuities and thickness, even in seismically thin beds—in practical terms, typically down to about 15 ft.

Stochastic fluid-modulus inversion, which is being used as a risking tool for quantifying the uncertainty in finding gas versus brine in conventional reservoirs, can be used to assess the value of seismic attribute data as a hydrocarbon indicator in tighter sands.

An example of a targeted workflow that focuses on identifying sweet spots of relatively higher porosity in a partly developed, generally tight sand might include the following tasks: (1) identification of key problems, review of existing data quality, and suitability of available new technology; (2) conventional interpretation of production, well log and seismic data, including building stratigraphic and structural models; (3) application of Instantaneous Spectral Analysis for hydrocarbon detection, reservoir thickness determination, and/or identification of reservoir discontinuities; (4) ANN inversion for reservoir properties using well-log, seismic, and spectrally decomposed seismic data as input; (5) high-resolution geological model building; (6) application of stochastic fluid-modulus inversion to address the potential for uncertainty introduced by incorporating seismic attribute data into the final model; and (7) simulation.

Although key attributes for each unconventional gas-reservoir type are listed in the text, most published work identifying key reservoir attributes has focused on areas outside the Midcontinent (e.g., the Rockies). It is anticipated that as more characterization studies are done in the Midcontinent that take a targeted workflow approach, the lists of key attributes will be refined, and specific technologies and/or applications of existing technologies will evolve.

Decker, Carrie, 2005, Targeted reservoir characterization of unconventional gas: tight sand, coalbed methane, deep gas, and fractured gas shale, *in* Cardott, B. J. (ed.), Unconventional energy resources in the southern Midcontinent, 2004 symposium: Oklahoma Geological Survey Circular 110, p. 1–6.

INTRODUCTION

Reservoir characterization is a term commonly used to describe a wide variety of activities, and, in practice, remains ill defined. Most commonly, it is used to describe the integration of geological, geophysical, and production data and analyses to characterize reservoir properties in three dimensions. Recently, technology needs for improving unconventional gas production in basins across the nation were identified (Engler and Perry, 2002). In the Midcontinent, key needs included reservoir characterization and imaging, stimulation technologies, data mining and reproducibility models. The need for improved reservoir characterization was common to all regions. The objectives of successful reservoir characterization include siting new wells, applying optimal completion and stimulation technologies, and recovering bypassed gas due to compartmentalization and prior production. The typical data available for reservoir characterization may include any of the following (generally ranked from most to least common):

- Analog field or outcrop.
- Well-log data.
- Production data.
- Seismic data (2-D, 3-D, multicomponent, and/or time-lapse).
- Well-test data.
- Core data (sidewall and/or full core).
- Geochemical data (for hydrocarbons and/or water).
- Other geophysical measurements (for example, magnetic, gravity, or magnetotelluric data).

To effectively perform reservoir characterization, sufficient data must exist so that the resulting reservoir description describes characteristics at the scale of heterogeneity influencing reservoir production. In fact, a branch of reservoir characterization—high-resolution reservoir characterization—is used to generate a "volumetric picture of rock and fluid characteristics at any location in the reservoir at the scale of wireline logs." Such a description is likely to lead to unwieldy simulations, however, in complex reservoirs. Rather, it is preferable to describe the interwell-reservoir characteristics at a relatively high resolution. One way to guide interpretation of interwell properties is to use seismic data, which generally has a smaller bin size than well spacing.

Unfortunately, seismic data over many unconventional reservoirs does not always exist. Past emphasis on using 2-D or 3-D seismic data for exploration or development has focused on structural (and sometimes stratigraphic) interpretation and identification of "bright spots" (amplitude anomalies) that are used as indicators for gas. These approaches are not as valuable for thin beds, tight reservoirs, and particularly where exploration through the drill bit is less expensive than seismic-data acquisition, even in parts of the southern Midcontinent, such as Oklahoma, where there are tax incentives for production associated with 3-D seismic.

The challenge, for unconventional gas reservoirs, is to determine which factors that contribute to reservoir heterogeneity have the most impact on production. This approach makes the best use of available input data, focuses the resultant workflow to optimize time and cost, and ideally, makes use of cutting-edge technology to best describe key reservoir properties at the appropriate scale.

METHODOLOGY

The approach taken in this paper is to define several cutting-edge technologies that can add value to the reservoir-characterization workflow for unconventional gas resources, then to define reservoir parameters that have the most impact on production in key unconventional gas-reservoir types. It is anticipated that key properties controlling production vary from one type of unconventional gas reservoir to another. Therefore, a workflow that would be appropriate for characterizing tight gas sand would be very different from one for coalbed methane. Some of the properties may be similar to those with which production correlates in conventional oil and gas field, such as porosity and permeability (e.g., Haeberle, 2003). However, several will be quite different. Focusing on key parameters helps determine the appropriate technology and optimal workflow for a particular field, thus reducing time and cost of reservoir characterization, which is critical to make this approach accessible to producers.

For each of four key unconventional gas types (coalbed methane, fractured gas shale, deep gas, and tight gas sand), key parameters are described. For tight gas sand, a reservoir characterization workflow utilizing cutting-edge technology is suggested.

At this point, although key parameters have been identified, sensitivity studies to test the relative impact of key parameters on production still need to be done for more fields representing each of the different unconventional gas types. By testing the sensitivity of production to these parameters, then considering only those that most effect production, future workflows can become further focused, and increasingly cost and time effective.

Simulation, the final step in many reservoir characterization workflows, not only provides for studying the sensitivity of various key parameters, but also tracks changes in parameters during production (e.g., pressure drawdown and extent of gas desorption in coalbed methane; Young and Paul, 1993) that are not always captured by geologic and geophysical reservoir description (which typically looks at a snapshot during the life of the reservoir, unless time-lapse seismic data are used). Integration of geologic, geophysical, and engineering data and analyses is critical to successful reservoir characterization in any environment.

TECHNOLOGIES

What follows is not an exhaustive list of appropriate or even cutting-edge technologies, but rather an overview of some of key technologies that can be used for each of several objectives. Many technologies are out there that can still be considered "new" because they are still not universally used for reservoir characterization, including interpretation of multicomponent seismic data for fracture or other anisotropy, cross-well seismic for determining reservoir attributes at a high resolution between wells, and formation micro-scanning or FMS logs for viewing fractures in the borehole. This section focuses on Instantaneous Spectral Analysis and stochastic fluid-modulus inversion in greater detail, because information on these technologies is not so widely available in the literature.

For all cutting-edge technologies, integration of key results with conventional analyses, and interpretation in a context that is reasonable in a geologic and engineering sense, yields results that add value to reservoir characterization. It should be noted that the converse is true—interpreting results of new technologies in a reservoir characterization context can be preferable to interpretation of results of new technology without valuable contextual input.

Because the technologies described below rely on seismic data for input, it is important to remember that successful reservoir characterization, integrating seismic data (with two-way travel time as the vertical dimension) with depth-based input, such as well-log data, requires a good understanding of the velocity field over the region of interest. In highly complex reservoirs, time-depth correlation may vary significantly across the area, and requires special attention.

Sometimes, relatively new technologies that can add value to a reservoir characterization study may require the acquisition of new data, which can be relatively costly, depending on the scale of the study and the environment in which the data need to be collected (3-D seismic, multicomponent seismic, core data). Alternatively, new technology may entail new ways of analyzing existing data (spectral decomposition, if 2-D or 3-D seismic data have been collected already).

Instantaneous Spectral Analysis

Instantaneous Spectral Analysis is a wavelet-transform–based spectral decomposition technology that optimizes resolution vertically, laterally, and in terms of frequency (Castagna and others, 2002). Spectral decomposition, which involves separating out broadband-seismic data into its component frequencies, is being used more and more as a prospecting tool, and an increasing number of commercially available products use different transforms to go from the input seismic data to the spectrally decomposed output. Most forms of spectral decomposition yield attribute data that show an improved resolution laterally over conventional seismic data and can be used to interpret small-scale reservoir changes or discontinuities that contribute to compartmentalization. Wavelet-transform–based spectral decomposition, however, also optimizes vertical resolution, eliminating windowing problems associated with, for example, Fourier-transform based methods. This technology also optimizes resolution in terms of frequency, so that it has been applied successfully in conventional gas reservoirs to detect hydrocarbons.[1] Because Instantaneous Spectral Analysis uses a wavelet-transform algorithm to maximize resolution vertically and laterally as well as in the frequency domain, it also delivers useful information about reservoir discontinuities and thickness, even in seismically thin beds—in practical terms, typically down to about 15 ft.

The ability to interpret changes in reservoir discontinuities and thickness leads to improved ability to identify channels. In the Rockies, channels have not only been shown to be associated with sweet spots in tight sands, but may be linked to elevated natural fracture distribution (Ammer, 2002).

Because of the elevated resolution of spectrally decomposed output, it is ideal for use in characterizing complex reservoirs. In addition to being interpreted directly, it can be used as high-resolution input, with well-log data, for example, into Artificial Neural Network (ANN) inversion (e.g., Urquidi-Macdonald and others, 1991; Russell and others; 2004) for reservoir attributes such as porosity, permeability, and saturation, yielding an improved picture of interwell-reservoir properties.

Although spectral decomposition has been used commercially to predict changes in fluid content and reservoir thickness, the technology also responds to changes in rock properties, which may prove to be the most useful application for most unconventional gas reservoirs, for example in terms of interpreting changes in fracture density.

Stochastic Fluid-Modulus Inversion

Stochastic fluid-modulus inversion is a statistical comparison of real and synthetic seismic attributes, using all known or inferred information about a reservoir unit, to quantify the probability of a particular fluid modulus and fluid density at a given point in the reservoir (White and Castagna, 2002). It can be used as a risking tool in conventional reservoirs to quantify the uncertainty in finding gas versus brine, but it is most effectively used to assess the value of seismic-attribute data as a hydrocarbon indicator in tighter sands.

Stochastic fluid-modulus inversion is an example of a technology that, at this stage in its development, may be appropriate for tight sand (if used to evaluate the value of seismic data for determining hydrocarbon content) but not for other unconventional gas-reservoir characterization workflows, underscoring the need for appropriate application of new technology. It should be noted, however, that it is sometimes instructive to apply technology that is marginally applicable when it is within time and cost budgets to do so and if potential exists for additional information about reservoir properties.

[1]Gas, for example, illuminates at a higher tuning frequency than brine; attenuation of high frequencies by gas-bearing units can also be interpreted from spectrally decomposed data if the frequency resolution is sufficiently high.

PARAMETERS: COALBED METHANE

Production of coalbed methane is becoming increasingly important to the independent producer in the southern Midcontinent. Coalbed-methane resources include those of the Arkoma Basin. Most published work characterizing coalbed-methane reservoirs has focused on the Rockies. However, for most coalbed methane, regardless of the geographic area, the key parameters are:

- Drainage area, thickness of producing zone(s).
- Coal depositional environment, coal rank (which may correspond to structural trends).
- Cleat porosity.
- Radial permeability.
- Stress state, which, coupled with cleat orientation, may indicate a preferred direction for permeability (e.g., Tyler and others, 1994), or which may influence fracture treatment design (Stevens and others, 1992).
- Sorption characteristics.
- Gas properties.
- Hydrodynamics.
- Correct evaluation of gas-in-place; gas-in-place may be calculated from gas content, which (in turn) may or may not be correctly predicted by depth for a given coal rank (Stevens and others, 1992). Correct prediction of gas content from depth may depend on understanding the complex geologic history for a given basin. Measurement of gas content may be problematic; there is a growing concern that existing measurements commonly underestimate the resource.
- Association with tight-gas, fractured shales; the idea of treating these groups of associated unconventional gas types as a package that can be jointly considered a resource and developed with a plan that optimizes exploitation of all types simultaneously, is coming under discussion (e.g., Tyler and others, 1994).

To highlight the complexity of coalbed-methane reservoirs, one example (Paul and Young, 1993) from the Rockies shows variability in absolute cleat permeability from 0.1 to 50 md, in gas content from 100 to 500 scf/ton, and in reservoir pressure from 200 to 1,600 psia.

The same study (Paul and Young, 1993) tested the sensitivity of production to several of the parameters listed above, and determined that the most critical parameters in that field (in the Fruitland coal) were cleat permeability, gas content, and the adsorption isotherm.

PARAMETERS: FRACTURED GAS SHALE

The principal resource for shale gas production in the southern Midcontinent is the Barnett Shale. Other localized resources have yet to be well-characterized, and it remains to be seen if these resources have similar key characteristics to those observed in the well-published Appalachians, northern Midcontinent, and Rockies. To date, identified key parameters affecting production from fractured gas shale include:

- Drainage area size, shape, and orientation.
- Fracture versus matrix porosity.
- Permeability.
- Anisotropy.
- Fracture length, spacing, conductivity.
- Relationship between natural and induced hydraulic fractures.
- Mechanical properties.

Of these parameters, natural fracture characteristics dominate control on production (e.g., K & A Energy Consultants, 1993b). In some fields (e.g., in some Devonian shales), lithologic variations do not seem to significantly impact production. ResTech Houston (1995) noted that gas porosity and kerogen content, however, may contribute to productivity.

Because individual fractures may be limited in lateral and vertical extent, multiple fracture sets, forming a three-dimensional permeability network, are important for good production (K & A Energy Consultants, 1993a; ResTech Houston, 1995; Decker and others, 1992). K & A Energy Consultants (1993a), however, cautioned that fractures in fractured gas shale may not be as effectively captured by imaging tools such as FMS logs as in other rock types.

PARAMETERS: DEEP GAS

Deep gas (>15,000 ft) is different from other unconventional gas types in that it encompasses a wide range of structural and stratigraphic styles. In the Rockies, structural traps are important, as is structural compartmentalization of reservoirs. In the Midcontinent, source availability and local/historical thermal profiles may play a role (Dyman, 1991). Offshore, in an area that is currently receiving a great deal of attention, stratigraphic traps may play a critical role, and understanding depositional and charge history is critical. Because very few wells have been drilled to depths greater than 15,000 ft (less than 5% of all wells drilled on the Gulf of Mexico shelf, according to 2001 data), much of the available information draws from seismic data (Wood and others, 2003). In all cases pressure compartmentalization may be an issue.

In general the key parameters that must be identified for successful reservoir characterization of deep gas include:

- Trap type, structure, stratigraphy.
- Porosity, permeability, saturation.
- Pressure, temperature.
- Charge, gas chemistry.

PARAMETERS: TIGHT SAND

A typical tight gas sand resource for the southern Midcontinent might include those of the Anadarko Basin. The key parameters controlling production for a tight gas sand are:

- Stratigraphy, structure.
- Porosity, permeability.
- Fracturing parameters: length, spacing, connectivity, anisotropy.
- Mechanical properties.

What follows is a generalized workflow for a tight gas sand that makes use of the technologies described above, targeting the controlling parameters for tight sand, including changes in porosity that may control localized "sweetspots" and changes in fracture porosity. For each field, however, the available data and the specific objectives of a reservoir characterization project, as well as budgeted time and cost, will dictate the actual workflow.

Conventional reservoir characterization activities, including review of existing data quality, and suitability of available new technology and interpretation of production, well log and seismic data, including building stratigraphic and structural models are necessary even in an unconventional-gas–targeted workflow.

Application of cutting-edge technologies to determine reservoir properties include Instantaneous Spectral Analysis for hydrocarbon detection, reservoir thickness determination, identification of reservoir discontinuities, and (most especially) changes in rock properties. Changes in reservoir properties potentially include changes in reservoir quality (for example, changes in clay content, which increases attenuation; e.g., Tutuncu and others, 1992) or more likely, changes in fracture porosity. Additional application of cutting-edge technologies includes ANN inversion for reservoir properties using well-log, seismic, and spectrally decomposed seismic data as input; high-resolution geological model building; application of stochastic fluid modulus inversion to address the potential for uncertainty introduced by incorporating seismic attribute data into the final model; and simulation.

CONCLUSIONS

Not all unconventional gas types have the same reservoir characterization needs as conventional gas reservoirs or as other types of unconventional gas.

Based on past studies, key parameters can be identified for each unconventional gas type that most influence production. The need to quantify these parameters dictates the technologies that should be used to describe changes in these properties across the reservoir, including between wells, as well as a targeted reservoir characterization workflow.

Integration of new technologies with conventional analyses adds value to either approach used separately.

The complexity of the reservoir dictates the scale at which the key reservoir properties must be described. Many unconventional reservoirs are structurally or stratigraphically complex, mandating detailed reservoir description between wells.

Seismic-based technologies are currently one of our most rewarding technologies to determine interwell properties in areas where it is economically feasible to collect seismic data. With the increasing applicability of seismic technologies to determine changes in rock properties (as opposed to hydrocarbon indication alone), the range of areas over which acquisition of seismic data is economically feasible is growing.

Additional work will constrain further those parameters that exert the most influence on production, and will target further workflows appropriate for unconventional gas reservoirs. In particular, focused work in the southern Midcontinent may lead to revision of lists of key parameters based on prior studies in the Rockies and elsewhere.

Targeted workflows optimize time and cost, improving reservoir characterization as a tool for producers.

REFERENCES CITED

Ammer, J., 2002, Tight gas technologies for the Rocky Mountains: GasTIPS, v. 8, no. 2, p. 18–23.

Castagna, J.; Sun, S.; and Siegfried, R., 2002, The use of spectral decomposition as a hydrocarbon indicator: GasTIPS, v. 8, no. 3, p. 24–26.

Decker, D.; Coates, J-M.; and Wicks, D., 1992, Stratigraphy, gas occurrence, formation evaluation, and fracture characterization of the Antrim Shale, Michigan Basin: GRI-92/0258, Gas Research Institute, Chicago, 101 p.

Dyman, T., 1991, Geologic controls and resource potential of natural gas in deep sedimentary basins in the United States: GRI-91/0363, Gas Research Institute, Chicago, 51 p.

Engler, T.; and Perry, K., 2002, Creating a roadmap for unconventional gas R&D: GasTIPS, v. 8, no. 4, p. 16–20.

Haeberle, F. R., 2003, Reservoir property analysis can guide Texas Gulf Coast exploration: Oil and Gas Journal, v. 101.7, p. 38–43.

K & A Energy Consultants, Inc., 1993a, Characterization of natural fractures in the Devonian shale, GRI Experimental Development Research Area, Pike County, Kentucky: GRI-93/0197.1, Gas Research Institute, Chicago, 46 p.

_____1993b, Geologic controls on gas production, GRI Experimental Development Research Area, Pike County, Kentucky: Gas Research Institute, Chicago, 42 p.

Paul, G.; and Young, G., 1993, Characterization of Fruitland coal through reservoir simulation: GRI-0460.1, Gas Research Institute, Chicago, 155 p.

ResTech Houston, Inc., 1995, Development of laboratory and petrophysical techniques for evaluating shale reservoirs: GRI-95/0496, Gas Research Institute, Chicago, 286 p.

Russell, B. H.; Lines, L. R.; and Hampson, D. P., 2004, Application of the radial basis function neural network to the prediction of log properties from seismic attributes: Published online at http://www.hampson-russell.com/technicalpapers.htm.

Stevens, S.; Lombardi, T.; Kelso, B.; and Coates, J., 1992, A geologic assessment of natural gas from coals seams in the Raton and Vermejo Formations, Raton Basin: GRI-92/0345, Gas Research Institute, Chicago, 84 p.

Tyler, R.; Kaiser, W.; McMurry, R.; Nance, H.; Scott, A.; and Zhou, N., 1994, Geologic characterization and coalbed methane occurrence: Williams Fork Formation, Piceance Basin, northwest Colorado: GRI-94/0456, Gas Research Institute, Chicago, 218 p.

Tutuncu, A.; Sharma, M.; and Podio, A., 1992, The effect of clay content, stress, frequency, and saturation on compressional and shear velocities in tight gas sands: GRI-92/0193, Gas Research Institute, Chicago, 94 p.

Urquidi-Macdonald, M.; Javitz, H.; Park, W.; Lee, J.; and Bergman, A., 1991, Feasibility of calculating petrophysical properties in tight sand reservoirs using neural networks: GRI-91/0209, Gas Research Institute, Chicago, 138 p.

White, L.; and Castagna, J., 2002, Stochastic fluid modulus inversion: Geophysics, v. 67, no. 6, p. 1835–1843.

Wood, L.; Hentz, T.; Zeng, H.; De Angelo, M.; and Dutton, S., 2003, Applying sequence stratigraphy and seismic stratal slice technology in the Gulf of Mexico: GasTIPS, v. 9, no. 1, p. 10–21.

Young, G.; and Paul, G., 1993, Reservoir characterization of Mary Lee and Black Creek coals at the Rock Creek Field Laboratory, Black Warrior Basin: GRI-93/0179, Gas Research Institute, Chicago, 131 p.

Overview of Unconventional Energy Resources of Oklahoma

Brian J. Cardott
Oklahoma Geological Survey
Norman, Oklahoma

ABSTRACT.—Unconventional energy resources of Oklahoma include coalbed methane, gas shales, oil shales, tight gas and ultra-deep reservoirs, and oil sands. Coalbed methane (CBM), gas shales, and tight gas reservoirs are commonly referred to as continuous gas accumulations because they are regionally extensive, generally not buoyancy driven, and commonly independent of structural and stratigraphic traps.

Excluding workover wells, 704 vertical coalbed-methane (CBM) wells in the Arkoma Basin produced 46 billion cubic feet (Bcf) gas from 1989 to 2003, whereas 274 horizontal CBM wells in the Arkoma Basin produced 33 Bcf gas from 1998 to 2003. About 837 CBM wells in the northeast Oklahoma shelf produced >36 Bcf gas from 1994 to 2003.

Shale-gas production in Oklahoma is a frontier play. Potential gas shales in Oklahoma are the Woodford Shale (Upper Devonian–Lower Mississippian; <1–14% total organic carbon, TOC), Caney Shale (Mississippian; 2.02–5.4% TOC) and Mulky coal/Excello Shale (Pennsylvanian; 1–17% TOC). The Woodford Shale produced 27 Bcf gas from June 1961 to August 2003 from 20 Woodford-only wells in Bryan, Carter, Grady, Marshall, and McClain Counties. The Caney Shale produced 680 MMcf gas from February 1998 to August 2003 from four wells in Love, McIntosh, and Stephens Counties. Gas production from the Excello Shale is included with the Mulky coal.

Commercial quantities of oil and natural gas can be extracted from oil shales by retorting (heating to 500°C). Fischer Assay oil yields of the Woodford Shale were 8.4–20.3 gallons per short ton of rock, whereas hydroretorting assay oil yields on the same samples were 22.9–46.8 gallons per short ton of rock.

Tight gas and ultra-deep reservoirs in Oklahoma are poorly understood. Identified tight-gas plays include the Red Fork play in the Anadarko Basin of Oklahoma, the Cleveland and Granite Wash plays in the Anadarko Basin of Texas, and the Atoka Formation in the Arkoma Basin.

Rock asphalt was produced from oil sand pits in the Arbuckle Mountains for road-paving material from 1890 to 1962. Synthetic crude oil has never been a product of the Oklahoma asphalt deposits.

INTRODUCTION

Unconventional energy (oil and gas) resources may be defined broadly as energy resources that are difficult and costly to extract even with specialized technology. They traditionally include coalbed methane (CBM), gas shales, oil shales, tight sands, tight carbonates, ultra-deep reservoirs (basin-centered gas accumulations), oil (tar) sands, and gas hydrates (Law and Curtis, 2002; Dyni, 2003). Coalbed methane, gas shales, and tight gas reservoirs are commonly referred to as continuous gas accumulations because they are extensive regionally, generally not buoyancy driven, and commonly independent of structural and stratigraphic traps (U.S. Geological Survey, 1995; Schmoker, 1999; Popov and others, 2001; Law and Curtis, 2002). Henry and Finn (2003, p. 3) stated that: "Continuous gas accumulations are those in which the entire assessment unit is considered to be gas-charged. Within these assessment units, there may be wells drilled that are not economic successes but all are expected to contain gas."

According to Schmoker and others (1996, p. 96), "Common geologic characteristics of a continuous gas accumulation include occurrence downdip from water-saturated rocks, lack of obvious trap and seal, crosscutting of lithologic boundaries, large areal extent, relatively low matrix permeability, abnormal pressure (either high or low) and close association with source rocks. Common production characteristics of a continuous gas accumulation include large in-place gas volume, low recovery factor, absence of truly dry holes, dependence on fracture permeability, and a serendipitous 'hit or miss' character for production rates and ultimate recoveries of wells."

Non-conventional (or unconventional) fuels that were eligible for tax credits under the Internal Revenue Ser-

Cardott, B. J., 2005, Overview of unconventional energy resources of Oklahoma, *in* Cardott, B. J. (ed.), Unconventional energy resources in the southern Midcontinent, 2004 symposium: Oklahoma Geological Survey Circular 110, p. 7–18.

vice Code Section 29 from 1980–2002 included the following: (1) oil from shale; (2) oil from tar sands; (3) natural gas from geopressured brine, coal seams, Devonian shale, or tight sands; (4) liquid, gaseous, or solid synthetic fuel, including petrochemical feedstocks, (other than alcohol) from coal liquefaction or gasification facilities; (5) gas from biomass (including wood); (6) steam from solid agricultural by-products; and (7) qualifying processed solid wood fuels (Sanderson and Berggren, 1998).

Unconventional energy resources should not be confused with renewable energy supplies. Renewable energy supplies, which will not be covered, include biomass (plant and animal sources), wind (see Hughes and others, 2002, for application of wind power in Oklahoma), geothermal (see Nielson, 2003, for application of ground-source [geothermal] heat pumps in Oklahoma), solar, small-scale hydropower, wave and current, and tidal (Williams, 2003b; EIA, 2004).

Unconventional energy resources of Oklahoma include coalbed methane, gas shales, oil shales, tight gas and ultra-deep reservoirs, and oil (tar) sands.

COALBED METHANE

Coal is both a source and reservoir rock for natural gas. Natural gas from coal is rich in methane. Therefore, coalbed methane (CBM) is a methane-rich gas produced from coals. Methane is primarily adsorbed to the organic matter in coal. In 2002, CBM proved reserves in the U.S. were 18,491 billion cubic feet (Bcf) and accounted for 10% of U.S. dry-gas proved reserves. CBM production in the United States in 2002 was 1,614 Bcf and accounted for 8% of the dry-gas production (EIA, 2003). Limerick (2003) summarized the CBM reserves and production for U.S. coal basins. Oklahoma CBM basins (Arkoma and Cherokee) and six smaller U.S. coal basins accounted for 1% of U.S. CBM cumulative production through 2001.

The Oklahoma coalfield is in the western region of the Interior Coal Province (Cardott, 2002a). The first wells drilled specifically for CBM in Oklahoma were completed in 1988. CBM in Oklahoma is produced in the northeast Oklahoma shelf (Cherokee Platform) and Arkoma Basin. Through December 2003, 2,896 CBM completions were reported in Oklahoma—1,171 in the Arkoma Basin and 1,725 on the northeast Oklahoma shelf. Excluding workover wells, 704 vertical CBM wells in the Arkoma Basin produced 46 Bcf gas from 1989 to 2003, whereas 274 horizontal CBM wells in the Arkoma Basin produced 33 Bcf gas from 1998 to 2003. About 837 CBM wells in the northeast Oklahoma shelf produced >36 Bcf gas from 1994 to 2003. Cardott (2005 [this volume]) provided an update of CBM activity in Oklahoma.

GAS SHALES

Gas shales and oil shales are varieties of hydrocarbon source rocks, which are distinguished based on type and quantity of organic matter and thermal maturity. Organic-matter type refers to the kerogen or maceral type and can be grouped into gas-generative, oil-generative, or inert. Gas shales should contain either gas-generative organic matter or overmature oil-generative organic matter. Oil may decrease the permeability of shales containing mature (oil window) oil-generative organic matter. Organic-matter quantity is determined by the total organic carbon (TOC) content (weight percent, whole-rock basis). Vitrinite reflectance (%Ro, oil immersion) is the most common thermal-maturity indicator. Vitrinite is a maceral derived from the woody tissues of vascular plants. The oil window is considered to be from 0.5% to 1.3% Ro.

Gas shales are organic-rich, fine-grained sedimentary rocks (shale to siltstone) containing a minimum of 0.5 wt% TOC. Gas shales may be thermally marginally mature (0.4–0.6% Ro), mature (0.6–1.3% Ro), or overmature (>1.3% Ro) and contain biogenic to thermogenic methane. Gas is generated and stored *in situ* in gas shales as both sorbed (on organic matter) and free gas (in fractures and pores); thus, it is similar to natural gas in coals and, like coal beds, gas shales are self-sourced reservoirs (Curtis, 2002). Potential gas-shale resources occur where the greatest volume of organic-rich (high-TOC content) shale containing gas-generative organic matter is at moderate depth.

The requirement of natural fractures in shales for commercial gas-shale production is controversial. Hill and Nelson (2000), Curtis (2002), and Faraj and others (2004) suggest that low-permeable shales require extensive natural fractures to produce commercial quantities of gas. However, experience in the Barnett Shale and other shales indicates that induced fractures from stimulation (hydraulic fracturing) are necessary for gas shales to be economic (Faraj and others, 2004; Bowker, 2005 [this volume]).

Devonian gas-shale resources (362+ trillion cubic feet of gas-in-place, Tcf) in the eastern United States have been identified in the New Albany Shale (Illinois Basin), Antrim Shale (Michigan Basin), and the Ohio Shale (Appalachian Basin) (Martini and others, 2003). "The EIA estimates that there are 55.42 Tcf of technically recoverable shale gas in the United States, representing just under 5 percent of total recoverable resources" (NaturalGas.org, 2004).

Hill and Nelson (2000) indicated that most of the gas-shale production in the United States from 1979 to 1999 was from the Ohio Shale, Antrim Shale, New Albany Shale, Mississippian Barnett Shale (Fort Worth Basin), and Cretaceous Lewis Shale (San Juan Basin). They indicated that the Barnett Shale play is primarily in the gas window (vitrinite reflectance >1.0% Ro) at a depth of 6,500–8,500 ft. Other gas-shale plays occur at depths from 500 to 6,000 ft and thermal maturities from 0.4% to 1.88% Ro (Hill and Nelson, 2000).

Shale-gas production in Oklahoma is a frontier play. Johnson and Cardott (1992) summarized the oil-generative (types I and II kerogen) and gas-generative (type III kerogen) hydrocarbon source rocks in Oklahoma (Fig. 1). The Woodford Shale (Upper Devonian–Lower Mississippian), known primarily as an oil source rock with type II kerogen, may become an important gas shale. The Woodford Shale has less than 1–14% TOC (Comer, 1992; Hendrick, 1992; Johnson and Cardott, 1992; Cardott and Chaplin, 1993). Black shale laminations in the Woodford Shale can have as much as 25% TOC

SYSTEM	PRODUCING INTERVAL	HYDROCARBON-SOURCE ROCK	KEROGEN TYPE	TOC %
PERMIAN	PERMIAN (UNDIFFERENTIATED)			
PENNSYLVANIAN	VIRGILIAN	UPPER AND MIDDLE PENNSYLVANIAN	II III	<1-25
	DESMOINESIAN			
	ATOKAN			
	MORROWAN	MORROWAN	III	0.5-3.4
MISSISSIPPIAN	SPRINGER FORMATION	SPRINGER FORMATION	III	
	PRE-CHESTERIAN MISSISSIPPIAN (UNDIFFERENTIATED)	WOODFORD SHALE	II III	<1-14
DEVONIAN	HUNTON GROUP			
SILURIAN				
ORDOVICIAN	SIMPSON GROUP	SYLVAN SIMPSON GROUP	II I II	<1-9
UPPER CAMBRIAN	ARBUCKLE GROUP			

Figure 1. Paleozoic producing intervals, hydrocarbon source rocks, kerogen type, and total organic-carbon content (TOC %) of Oklahoma (modified from Johnson and Cardott, 1992).

(Roberts and Mitterer, 1992). Amsden (1989) delineated the thickness and extent of the Woodford-Chattanooga Shale in Oklahoma (Fig. 2). The Woodford Shale is >900 ft thick in the southern part of the Anadarko Basin (Amsden, 1975) and >200 ft thick in the southern part of the Arkoma Basin (Amsden, 1980). Amsden (1975, 1980) published structure maps of the Woodford Shale in Oklahoma. GTI (2000) and Hill and Nelson (2000) outlined the oil-productive area of the Woodford Shale in the Anadarko Basin on a gas shale resource map. Occurrences of oil and gas lease production from reservoirs within the Woodford Shale and correlatives are reported in Campbell and others (1993) and Northcutt and others (2001). The Woodford Shale is a potential gas shale in areas where the thermal maturity is higher than the oil window (>1.3% vitrinite reflectance). Figure 3 shows areas where the Woodford Shale is within the condensate/gas window at >1.3% Ro in the Anadarko, Ardmore, and Arkoma Basins. According to IHS Energy, the Woodford Shale produced 27,168,431 Mcf (thousand cubic feet) of gas from June 1961 to August 2003 from 20 Woodford-only wells in Bryan, Carter, Grady, Marshall, and McClain Counties in the Aylesworth, Caddo, Golden Trend, Madill, and Springer fields. Gas production by well is from Oklahoma Corporation Commission Form 1004. Well locations with Woodford Shale-only production based on Oklahoma Tax Commission lease data are shown in Figure 4.

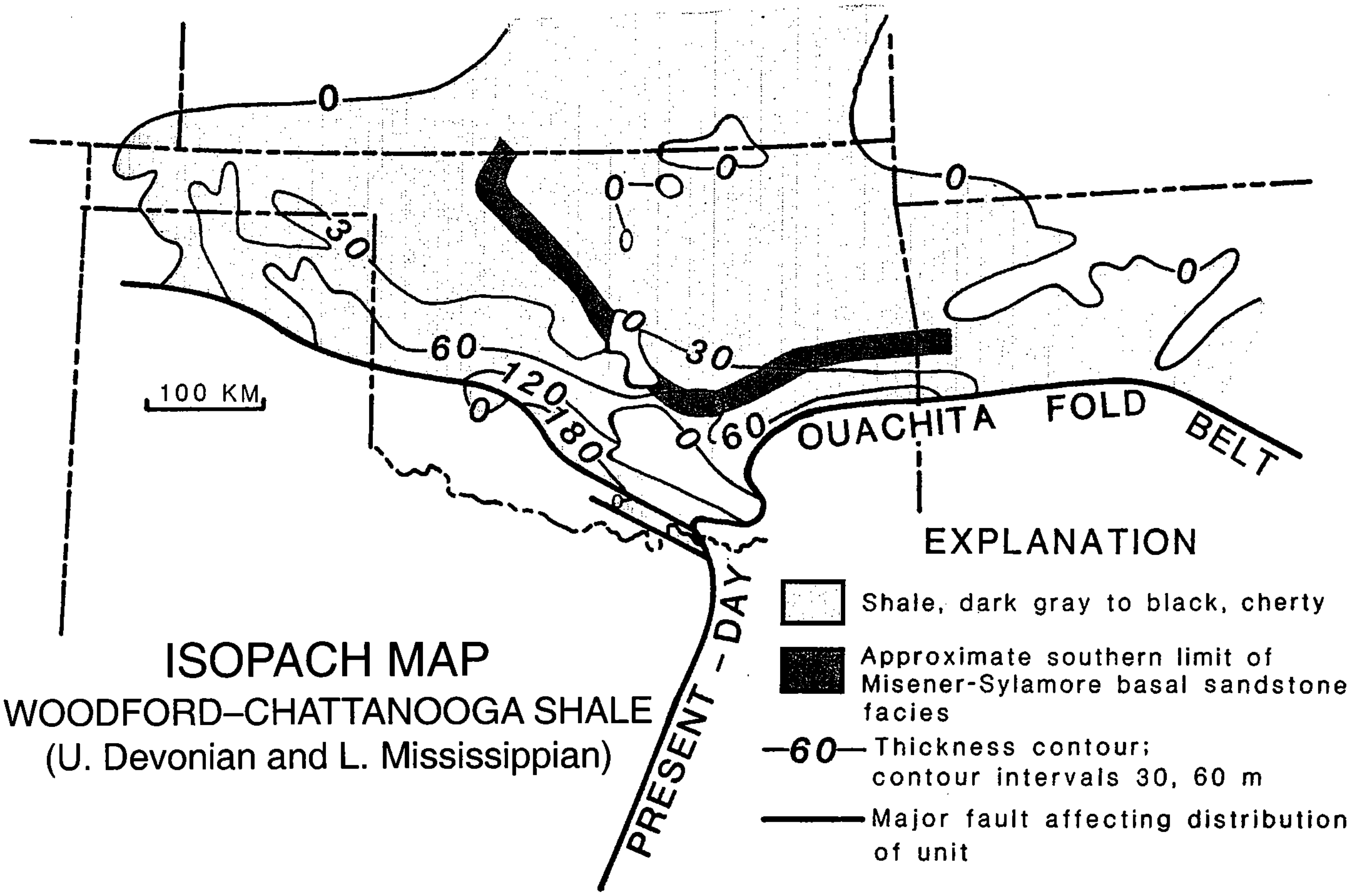


Figure 2. Woodford-Chattanooga Shale isopach and dominant lithologies map (modified from Amsden, 1989).

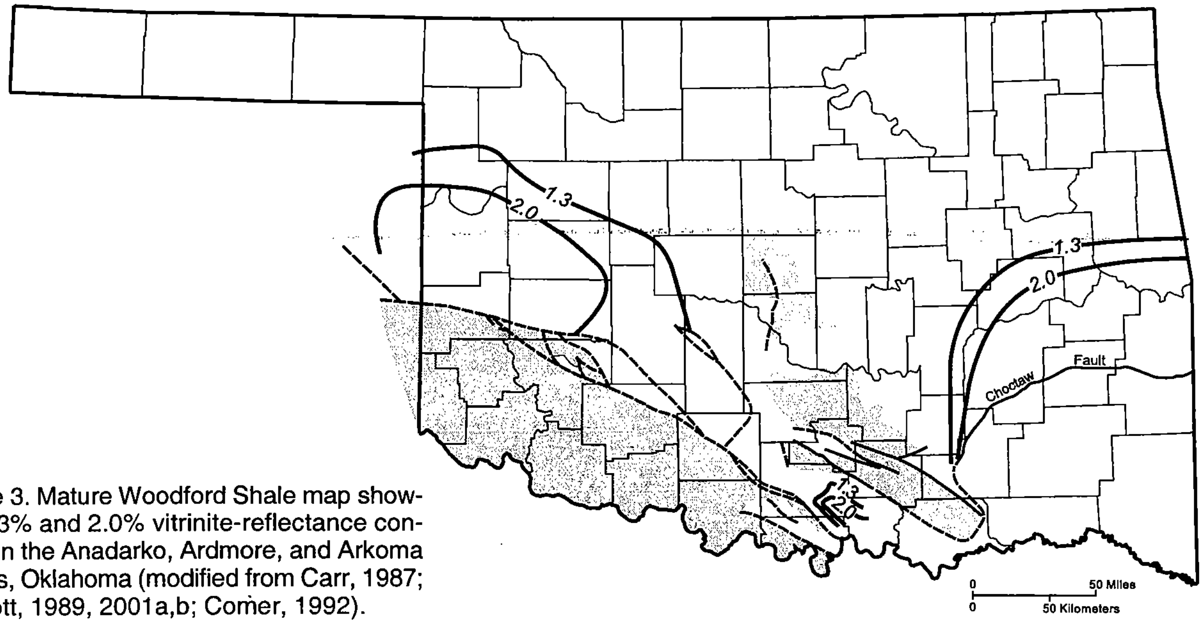


Figure 3. Mature Woodford Shale map showing 1.3% and 2.0% vitrinite-reflectance contours in the Anadarko, Ardmore, and Arkoma Basins, Oklahoma (modified from Carr, 1987; Cardott, 1989, 2001a,b; Comer, 1992).

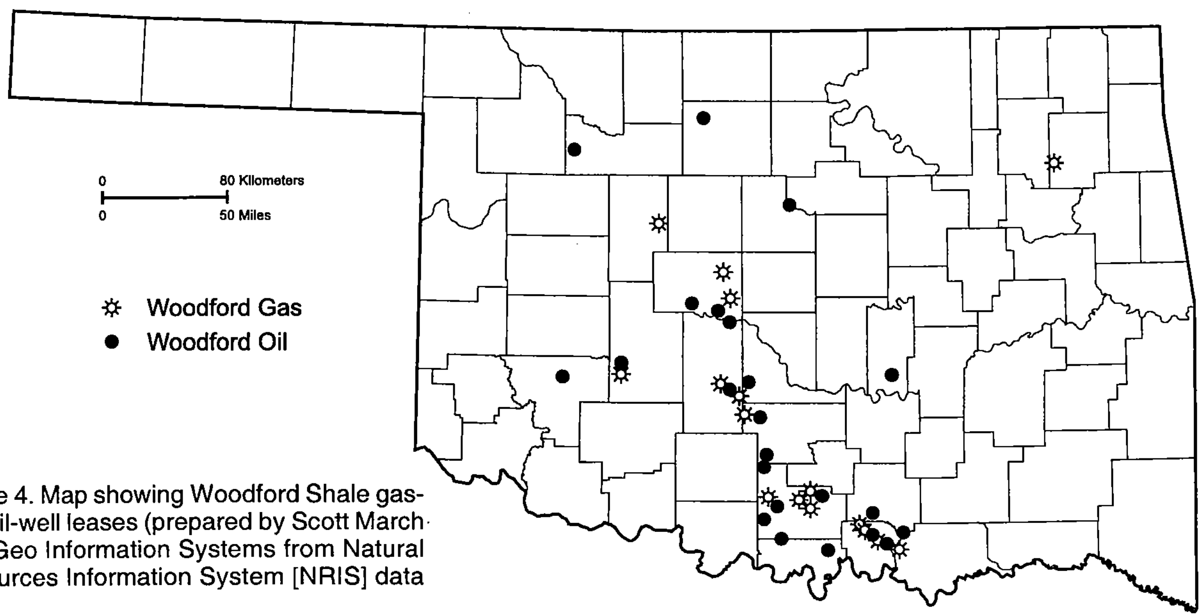


Figure 4. Map showing Woodford Shale gas- and oil-well leases (prepared by Scott March with Geo Information Systems from Natural Resources Information System [NRIS] data files).

Additional potential gas shales in Oklahoma are the Caney Shale (Mississippian) and Mulky coal/Excello Shale Member (Pennsylvanian). The Caney Shale interval is known by several names in southern Oklahoma. The Caney Shale is equivalent to parts of, in ascending order, the Sycamore Limestone, Delaware Creek Shale, and Goddard Formation in the Ardmore Basin and southwestern Arbuckle Mountains, and is divided into the Ahloso Member, Delaware Creek Member, and Sand Branch Member in the northeastern Arbuckle Mountains (Meramecian and Chesterian Series, Mississippian System; Elias and Branson, 1959; Sutherland, 1981; Monaghan, 1985). The Caney Shale members are differentiated based on paleontology rather than lithology (Sutherland, 1981). Weaver (1958) indicated that the Caney Shale is characterized by the abundance of illite clay minerals and may be used to distinguish the Caney Shale from other Upper Mississippian and Lower Pennsylvanian shales. Andrews (2003) described a "False Caney" above the true Caney Shale on electric logs. His cross sections indicate that the Caney Shale thickens from north to south and east to west to almost 300 ft in southern Hughes County in the Arkoma Basin. Structure and isopach maps of the Caney Shale are unavailable. The Caney Shale has oil-generative organic matter (Wavrek, 1992; Weber, 1994). The TOC content of the Caney Shale is 2.02–4.04% from 16 samples in the Arkoma Basin and 4.4–5.4% from three samples in the Ouachita Mountains (Hendrick, 1992; Cardott, 1994; Weber, 1994). According to IHS Energy, the Caney Shale produced 680,693 Mcf gas from February 1998 to August 2003 from four wells in Love, McIntosh, and

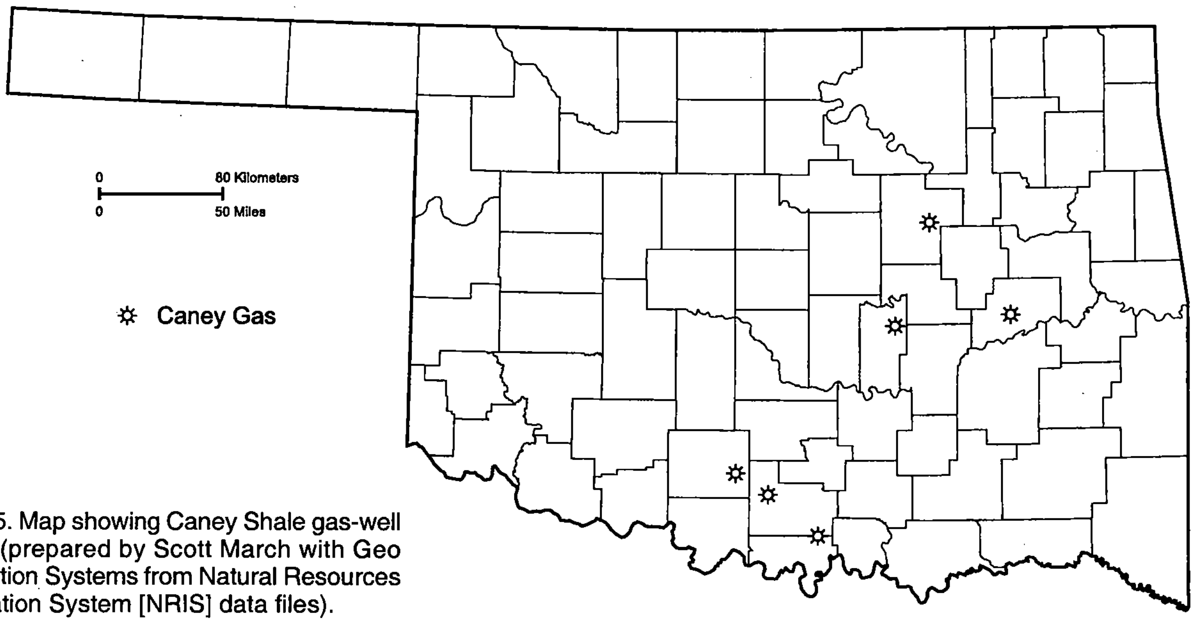


Figure 5. Map showing Caney Shale gas-well leases (prepared by Scott March with Geo Information Systems from Natural Resources Information System [NRIS] data files).

Stephens Counties in Enville West, Sho-vel-tum, Stidham Southeast, and Vernon North fields. Well locations with Caney Shale production based on Oklahoma Tax Commission lease data are shown in Figure 5.

Nelson and Pratt (2001) recommended including gas content from higher density (1.75–2.4 g/cm^3) impure coals/carbonaceous shales in calculating the net coalbed-reservoir thickness in coalbed-methane wells after realizing that some CBM wells produced more gas than the calculated gas-in-place reserves. The Mulky coal, the uppermost coal in the Senora Formation, occurs at the base of the Excello Shale Member and varies in composition from pure to impure coal with increasing amounts of mineral matter (Cardott, 2002a). The Mulky coal is one of the most important CBM reservoirs in the northeast Oklahoma shelf (Cardott, 2002b). Hemish (2002, p. 3) made the following statement: "The occurrence of the Mulky coal downdip to the west in Nowata, Washington, and Osage Counties has not been verified by the OGS from coring. It seems probable that the methane is being produced from the Excello black shale." Cassidy (1968) indicated that outcrop samples of the Excello Shale near Tulsa had an average composition of 17.9% organic matter (not related to TOC) with a range of 13.5–23.4% and 9.4% bitumen. Excello Shale core samples from northeast Oklahoma had 7.5–11.0% TOC (James and Baker, 1972). Ece (1987a,b) described the stratigraphy, paleogeography, depositional environments, and shale petrology of the Excello Shale. The black shale lithofacies of the Excello is as much as 6.7 ft thick in Rogers and Craig Counties, Oklahoma (Ece, 1987a). Ece (1989) described the thermal maturation, hydrocarbon-generation potential, and organic facies of the Excello black shale in Oklahoma, southeast Kansas, and Missouri. The Excello Shale contains a mix of types II and III kerogen (Fig. 6). TOC content of the black shale lithofacies in the Excello Shale ranges from 1 to 17 wt% (average of 10 wt%) (Ece, 1989). Thermal-maturity data of Excello Shale core samples from western Oklahoma are in error due to the inclusion of recycled vitrinite. Wenger and others (1988) indicated that a core sample of the Excello Shale from Rogers County, Oklahoma, had 13.3% TOC and a hydrogen index (HI) of 321 mg HC/g TOC, whereas core samples from Kansas had up to 25.2% TOC and HI of 382 mg HC/g TOC. Hatch and Leventhal (1997) reported that Excello Shale core samples from two wells in northeast Oklahoma had 5.5–15.2% TOC and HI of 57–290 mg HC/g TOC. Mixed oil and gas source rocks have an HI of 200–300 mg HC/g TOC when immature, whereas oil source rocks have an HI >300 mg HC/g TOC (Peters and Cassa, 1994). Gas produced from the Excello Shale Member has been included with gas produced from the Mulky coal.

OIL SHALES

Duncan and Swanson (1965, p. 3) defined oil shale as an "organic-rich shale that yields substantial quantities of oil by conventional methods of destructive distillation of the contained organic matter, which employ low confining pressures in a closed retort system." Oil shale is further defined as "any part of an organic-rich shale deposit that yields at least 10 gallons (3.8 percent) of oil per short ton of shale" (Duncan and Swanson, 1965, p. 3). Tissot and Welte (1984, p. 254) stated, "There is actually no geological or chemical definition of an oil shale. In fact, any shallow rock yielding oil in commercial amount upon pyrolysis is considered to be an oil shale." Hutton (1995, p. 17) indicated that "an oil shale is defined as a sedimentary rock that contains organic matter that, when retorted, produces sufficient oil to produce more energy than the energy required to produce the oil initially." Lithologically, oil shales are

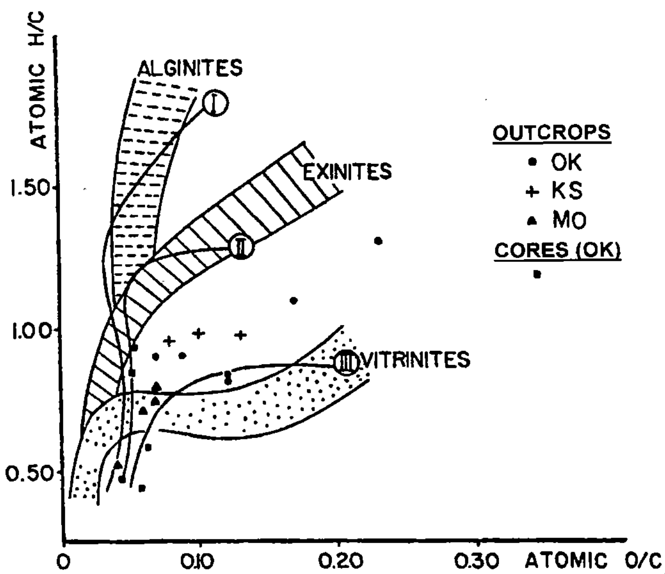


Figure 6. Van Krevelen diagram showing kerogen types of Excello Shale outcrop and core samples (modified from Ece, 1989).

mudstone, siltstone, marlstone, or carbonate, range in age from Cambrian to Tertiary, are thermally immature to mature with respect to oil generation, are organic-rich, and occur near the surface (Tissot and Welte, 1984; Dyni, 2003). Oil shales contain a minimum of 5 volume percent (not directly related to TOC) oil-generating organic matter (hydrogen-rich liptinite macerals, particularly alginite and fluoromorphinite, from types I and II kerogen) (Tissot and Welte, 1984; Hutton, 1995). Commercial quantities of oil and natural gas can be extracted from oil shales by mining, crushing and retorting (heating to 500°C).

Oil-shale deposits that are currently being exploited are in Estonia, Brazil, and China (Dyni, 2003). The largest oil-shale resources in the world are in the Green River Formation (Eocene) in Colorado, Utah, and Wyoming. The Green River Formation has an oil yield greater than 25 gallons per ton (Nowacki, 1981). Summaries of world oil-shale deposits are in Tissot and Welte (1984), Russell (1990), and Dyni (2000, 2003).

Oil shales that contain type I kerogen have the highest conversion of organic matter into shale oil (Tissot and Welte, 1984). However, shales containing type II kerogen also produce oil upon distillation. The Woodford Shale (Upper Devonian–Lower Mississippian) in Oklahoma contains mainly type II kerogen (Johnson and Cardott, 1992). The Woodford Shale in the Arbuckle Mountains is a marginally mature (defined as having a vitrinite reflectance of 0.4–0.6% Ro) hydrocarbon source rock (Cardott and others, 1990). Swanson (1960) and Landis (1962) reported that 7 samples of the Woodford Shale from Murray County, Oklahoma, had an oil yield of 3.8–15.3 gallons per ton (average of 11.5 gallons per ton), determined by the modified Fischer Retort method. Hycrude (1986) evaluated the oil yield of an exposure of the Woodford Shale in the Arbuckle Mountains. Ninety pounds of Woodford Shale (Sample No. MH-4) was collected from the Hunton quarry and Woodford Shale pit located in the SE¼SE¼NW¼ sec. 31, T. 1 S., R. 3 E. (Murray County, Oklahoma). Shale from this quarry is used on county roads. The Woodford Shale at this locality is marginally mature and contains type II kerogen with 9.5% TOC. Conditions for test runs 13, 22, 23, and 24 were 550°C , 541°C (30 minutes), 541°C (60 minutes), and 545°C (120 minutes), respectively. The Fischer Assay oil yields were 8.4–20.3 gallons per short ton of rock, whereas the hydroretorting assay oil yields on the same samples were 22.9–46.8 gallons per short ton of rock. Hydroretorting is the heating (>540°C) of shale in a retort under a hydrogen-rich atmosphere at elevated pressures (1,000 psi). In summary, the Woodford Shale in southern Oklahoma is a potential oil shale based on limited data determined under test conditions.

TIGHT GAS AND ULTRA-DEEP RESERVOIRS

"Tight gas sands are low-permeability gas-bearing reservoirs (in a variety of rock types) that have an *in situ* permeability to gas of less than 0.1 md, exclusive of natural-fracture permeability. The reservoirs are areally extensive, usually abnormally pressured, and often (but not always) found in basin-center settings" (Kuuskraa and Bank, 2003).

Tight gas and ultra-deep reservoirs (>15,000 ft) in Oklahoma are poorly understood. Al-Shaieb and Walker (1986) and Walker (1986) emphasized the development of secondary porosity (in what might be expected to be a tight-gas reservoir) in deep (depth range of core samples of 6,981 to 19,001 ft) Pennsylvanian Morrow sandstones in the Anadarko Basin. Popov and others (2001) and Law (2002) illustrated areas of potential basin-centered gas accumulations in the United States, including the Anadarko and Arkoma Basins in Oklahoma (Fig. 7). Popov and others (2001) distinguished continuous basin-center accumulations from low-permeability (tight) conventional accumulations by the former being abnormally pressured (either underpressured or overpressured). Popov and others (2001) included the Anadarko Basin in the list of high-potential accumulations. They made the following statement (p. 14): "Strong evidence for a basin-centered gas accumulation is present in the form of thermally mature source rocks, widespread production and shows of gas, and overpressuring that cuts across stratigraphic boundaries." Potential reservoirs include the Devonian–Mississippian Woodford Shale through the Pennsylvanian Oswego lime (Fort Scott Formation, Marmaton Group). "Shales, tightly cemented sands and other tight (low-permeability rocks) have the potential to produce where naturally fractured (many deep Anadarko Basin fields have permeabilities of less than 0.1 md)" (p. 16).

Popov and others (2001, p. 30) included the Arkoma Basin in the list of other potential accumulations and stated, "The extensive source rocks and high thermal-maturity levels in the Arkoma Basin indicate that basin-centered gas accumulations may exist which have not yet been identified. Thick Atoka shales probably provide the primary barriers to gas migration. In the

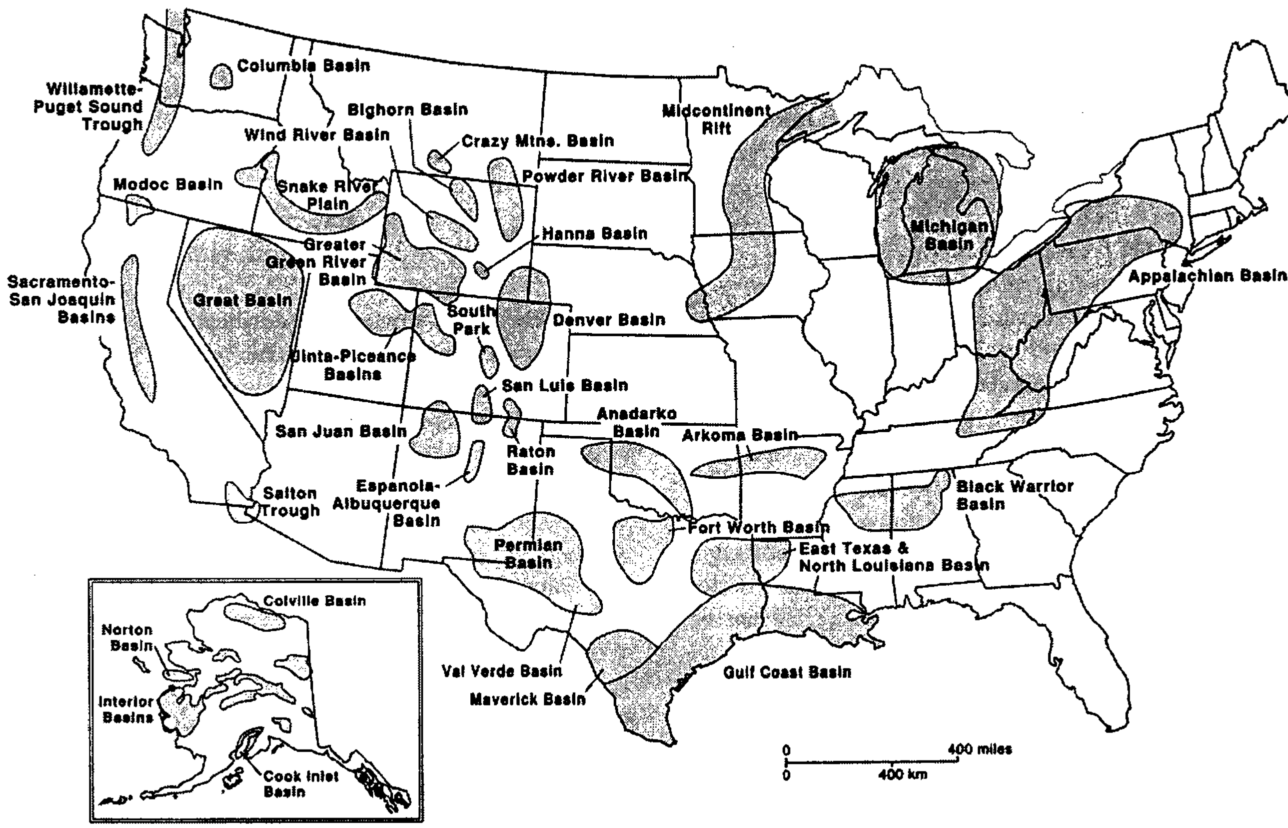


Figure 7. Map of the United States showing the geographic distribution of known and potential basin-centered gas accumulations (from Law, 2002).

lower Paleozoic section, several shale intervals encasing productive carbonate and sandstone reservoirs are thought to be effective seals."

GTI (2001) showed areas of a Red Fork tight-gas play in the Anadarko Basin of Oklahoma and Cleveland and Granite Wash tight-gas plays in the Anadarko Basin of Texas. Prouty (2001) provided reservoir properties for the Red Fork, Cleveland, and Granite Wash tight-gas plays in the Anadarko Basin. The Red Fork play has an average expected ultimate recovery (EUR) of 2,200–8,800 million cubic feet (MMcf) of gas per well at a depth of 9,000–13,000 ft, net pay of 7–200 ft, porosity of 1–18%, permeability of 0.1–20 md, and estimated ultimate recoverable of 2,890.6 Bcf. The Cleveland play has an average EUR of 1,000 MMcf/well at a depth of 5,500–12,000 ft, net pay of 6–55 ft, porosity of 3–14%, permeability of 0.001–20 md, and estimated ultimate recoverable of 702.9 Bcf. The Granite Wash play has an average EUR of 1,500 MMcf/well at a depth of 6,500–11,500 ft, net pay of 10–60 ft, porosity of 4–12%, permeability of 0.0009–1.4 md, and estimated ultimate recoverable of 349 Bcf. The Atoka Formation in the Arkoma Basin is also considered a tight gas reservoir (Prouty, 2001).

Ultra-deep reservoirs are present in the Anadarko and Arkoma Basins. The Anadarko Basin has some of the deepest wells in the United States (Dyman and others, 2003). Rogers and others (2004) described a U.S. Department of Energy benchmark study of wells >15,000 ft deep drilled from January 1, 1997 through December 31, 2001. They reported 372 wells drilled from 15,000 to 26,566 ft in the Anadarko Basin and 32 wells drilled from 15,047 to 17,638 ft in the Arkoma Basin.

OIL (TAR) SANDS

Rottenfusser (2003) made the following statement: "Oil sands (also called tar sands in the U.S.) are sandstones or carbonate strata containing bitumen or other hydrocarbons of such high viscosity as to be immobile under normal reservoir temperatures. In order to be utilized, the hydrocarbons must be mined or extracted *in situ* from the rock by the use of heat or solvents."

Portions of the following section are adapted from Cardott and Chaplin (1993, field-trip stops 5 and 7). A number of terms have been used in the literature for asphaltic material (e.g., oil sand, tar sand, bitumen, heavy oil, oil seep, and asphalt). According to Meyer and de Witt (1990), natural bitumens are semisolid or solid mixtures of hydrocarbons (composed of hydrogen and carbon) and as much as 50% heterocyclic compounds (containing sulfur, oxygen, nitrogen, and trace metals, especially iron, nickel, and vanadium). Natural bitumens are divided into two groups: pyrobitumens (in-bitumens (soluble in carbon disulfide). Soluble natural bitumens are divided into three subgroups: mineral wax, natural asphalt, and asphaltite. Natural asphalt ("asphalt"), the object of this discussion, is synonymous with the terms "oil sand" and "tar sand." Meyer and de Witt (1990) defined tar sand as any consolidated or unconsolidated rock that contains natural bitumen (viscosity >10,000 centipoises at reservoir temperature) and heavy oil as having an American Petroleum Institute (API) gravity <20° and viscosity <10,000 centipoises. The organic matter of tar sands is called extra-heavy oil, bitumen, tar, or asphalt, resulting from petroleum degradation in the reservoir (Tissot and Welte, 1984). Usage of the term "bitumen" in this report will refer to organic matter soluble in organic solvents (e.g., carbon disulfide), and the terms "asphalt" and "oil sand" will refer to any consolidated or unconsolidated rock that is impregnated with bitumen.

The Athabasca oil-sands deposit of northeastern Alberta, Canada, which contains more than one trillion barrels of bitumen in place, is the largest petroleum resource in the world (Rottenfusser, 2003). In-place bitumen resources in oil sands throughout Canada may be 2 trillion barrels (Williams, 2003a). Potential heavy-hydrocarbon reserves from oil sands in Canada are 315 billion barrels at current technology and economic conditions (Williams, 2003a).

Jordan (1964) compiled data on 297 occurrences of petroleum-impregnated rocks, asphaltite deposits (e.g., grahamite), and asphaltic-pyrobitumen deposits (e.g., impsonite) located in southern and northeastern Oklahoma (Fig. 8). Petroleum-impregnated rocks include: (1) sandstones and limestones, at or near the surface, that contain asphalt; and (2) rocks in the shallow subsurface (to a depth of 500 ft) that contain crude oil. More than 45 oil-sand sites were identified in the Arbuckle Mountains region (Johnson and others, 1984). Three commercial oil-sand deposits in the Arbuckle Mountains are known as the Dougherty (or Brunswick), Sulphur (or Buckhorn), and South Woodford districts. Cardott and Chaplin (1993) and Brown and Corrigan (1997) summarized the asphalt deposits in the Dougherty and Sulfur districts. Brown and Corrigan (1997) included a discussion on the origin of the Dougherty and Sulphur asphalt. Johnson and others (1984) and Harrison and Burchfield (1987) summarized the asphalt deposits in the South Woodford district.

The Dougherty district asphalt quarries were operated from 1890 to 1960. Harrison and Burchfield (1987) calculated the total probable in-place bitumen resource of the Dougherty district to be 3.6 million barrels. Johnson and others (1984) estimated the total production of bitumen-impregnated Viola Group limestone (Middle and Upper Ordovician) to be in excess of a million short tons (Fig. 9).

The Sulphur district asphalt quarries were open from about 1890 to 1962. Harrison and Burchfield (1987) calculated the total measured and probable in-place bitumen resource of the Sulphur district to be at least 46.4 million barrels. Johnson and others (1984) estimated the total production of the Sulphur district to be at least 1.5 million short tons of bitumen-bearing sandstone of the Oil Creek Formation (Simpson Group, Middle Ordovician) (Fig. 10). Bitumen-impregnated rock was quarried from the Dougherty district and Sulphur district and taken by truck to the crushing, screening, and mixing plant near Dougherty. The blended asphalt product was used as road-paving material. Synthetic crude oil has never been a product of the Oklahoma asphalt deposits.

Geologists with Suncor Energy, Inc. (Calgary, Alberta, Canada) evaluated the Sulphur oil-sand deposit in 1998 as part of a worldwide exploration for oil-sand reserves. Brian McKinstry (formerly with Suncor Energy; personal communication, June 2003) indicated that the Oklahoma deposits were structurally complex (dipping at steep angles) and had limited bitumen resources for a large-scale, economic oil-sand operation

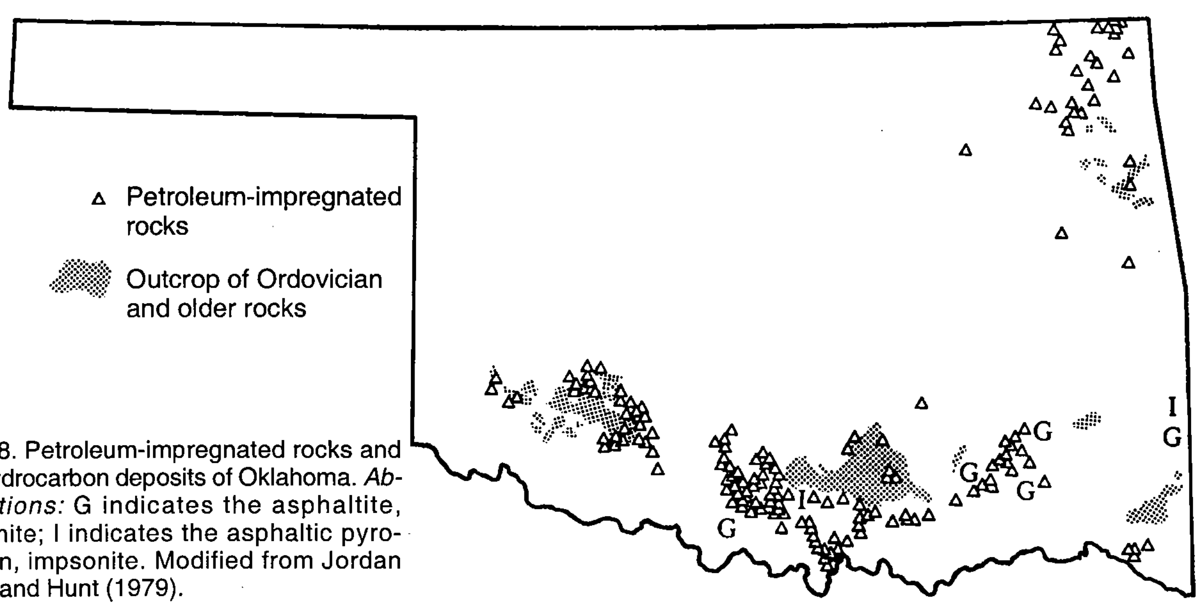


Figure 8. Petroleum-impregnated rocks and solid hydrocarbon deposits of Oklahoma. *Abbreviations:* G indicates the asphaltite, grahamite; I indicates the asphaltic pyrobitumen, impsonite. Modified from Jordan (1964) and Hunt (1979).

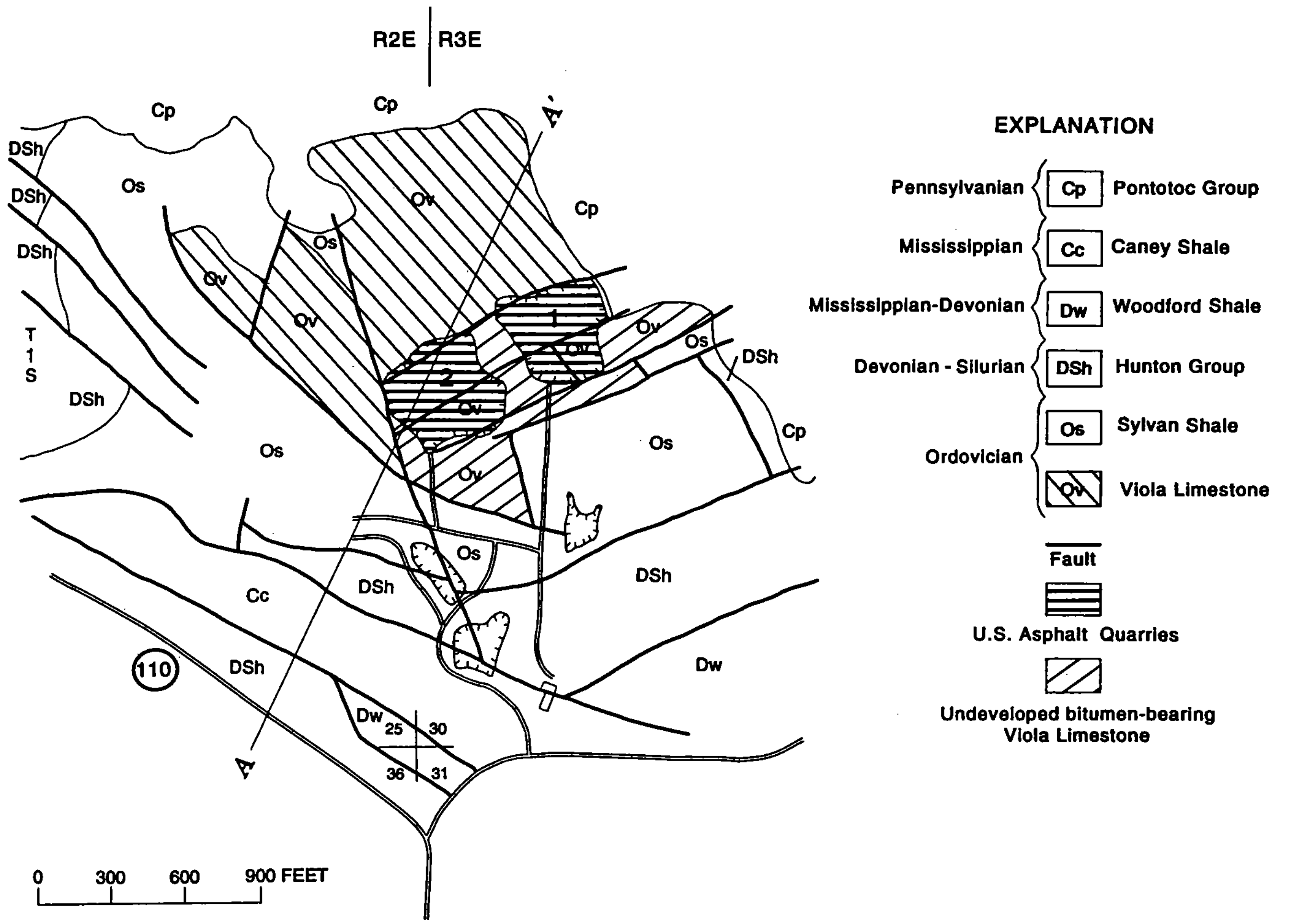


Figure 9. Geologic map of the Dougherty asphalt district. Numbers refer to U.S. Asphalt Co. No. 1 and No. 2 quarries (modified from Cardott and Chaplin, 1993).

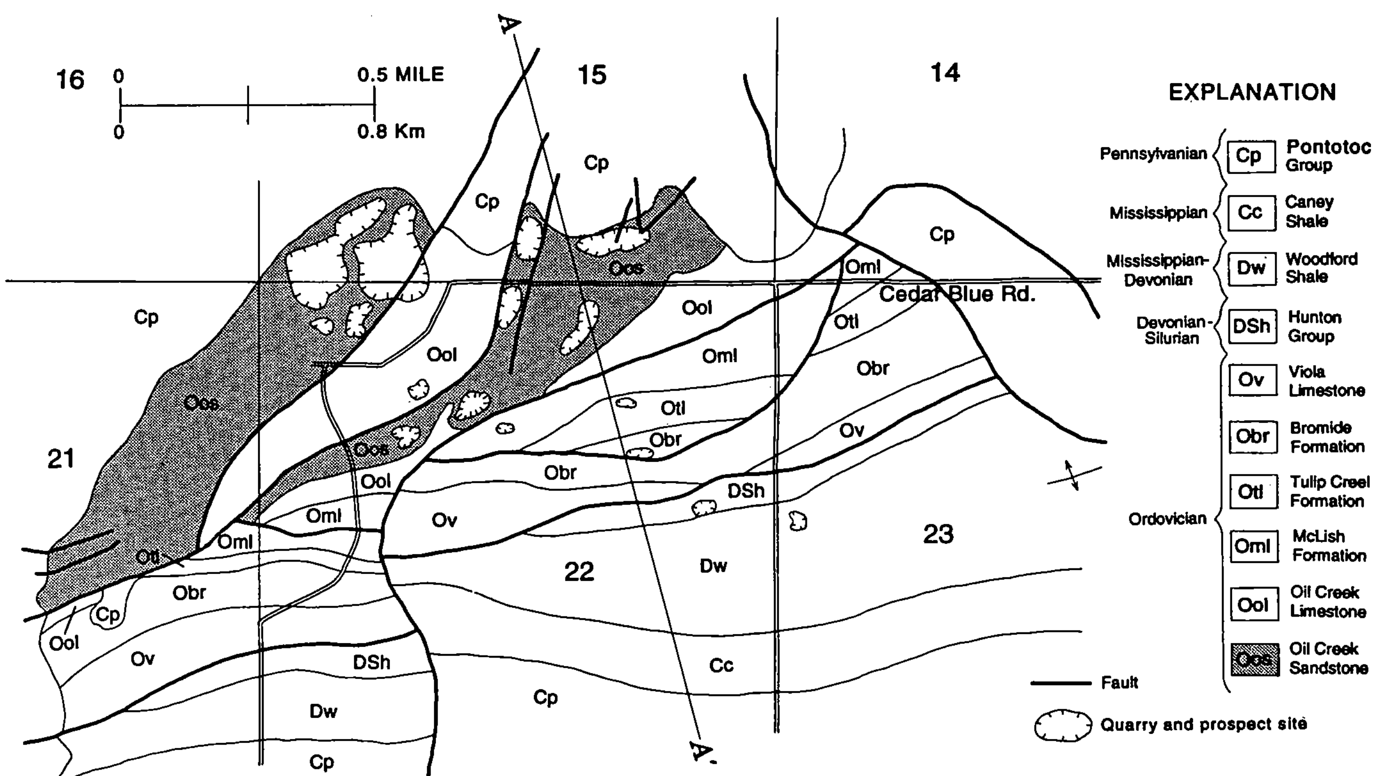


Figure 10. Geologic map of the Sulphur asphalt district (modified from Cardott and Chaplin, 1993).

sources for a large-scale, economic oil-sand operation compared with the Athabasca operation. In the end, Suncor decided to further develop Canada's oil sands resources (Moritis, 2004).

CONCLUSIONS

Potential unconventional energy resources of Oklahoma include coalbed methane, gas shales, oil shales, tight gas and ultra-deep reservoirs, and oil sands. The most actively pursued unconventional energy resource in Oklahoma currently is coalbed methane, with more than 2,600 wells drilled since 1988. Excluding old-well–workover wells, 704 vertical coalbed-methane (CBM) wells in the Arkoma Basin have produced 46 Bcf gas from 1989 to 2003, whereas 274 horizontal CBM wells in the Arkoma Basin have produced 33 Bcf gas from 1998 to 2003. About 837 CBM wells in the northeast Oklahoma shelf have produced >36 Bcf gas from 1994 to 2003.

Several shales in Oklahoma produce gas. The Woodford Shale (Upper Devonian–Lower Mississippian) produced >27 Bcf gas from 1961 to August 2003. The Caney Shale (Mississippian) produced 680 MMcf gas from 1998 to August 2003. Gas produced from the Excello Shale Member (Pennsylvanian) has been included with gas produced from the Mulky coal.

Tight gas and ultra-deep reservoirs in the Anadarko and Arkoma Basins of Oklahoma are poorly understood but have great potential. Retorting data on the Woodford Shale in the Arbuckle Mountains indicate limited oil-shale–resource potential. Limited bitumen resources in structurally complex oil sands in the Arbuckle Mountains indicate marginal potential. Premier oil sands and an oil shale in Oklahoma have been used as road material.

ACKNOWLEDGMENTS

I gratefully acknowledge that gas production data was supplied by Petroleum Information/Dwights LLC dba IHS Energy Group, © 2004, IHS Energy Group, all rights reserved. I thank Scott March with Geo Information Systems in Norman, Oklahoma, for preparing the Woodford Shale and Caney Shale lease maps. I thank Neil Suneson, Oklahoma Geological Survey, for comments on an earlier version of this paper.

REFERENCES CITED

Al-Shaieb, Z.; and Walker, P., 1986, Evolution of secondary porosity in Pennsylvanian Morrow sandstones, Anadarko Basin, Oklahoma, *in* Spencer, C. W.; and Mast, R. F. (eds.), Geology of tight gas reservoirs: American Association of Petroleum Geologists Studies in Geology 24, p. 45–67.

Amsden, T. W., 1975, Hunton Group (Late Ordovician, Silurian, and Early Devonian) in the Anadarko Basin of Oklahoma: Oklahoma Geological Survey Bulletin 121, 214 p.

_____ 1980, Hunton Group (Late Ordovician, Silurian, and early Devonian) in the Arkoma Basin of Oklahoma: Oklahoma Geological Survey Bulletin 129, 136 p.

_____ 1989, Thickness and dominant lithologies, Woodford-Chattanooga Shale (Upper Devonian and Lowest Mississippian), *in* Johnson, K. S.; and others, Geology of the southern Midcontinent: Oklahoma Geological Survey Special Publication 89-2, pl. 5.

Andrews, R. D., 2003, Cromwell play in southeastern Oklahoma: Oklahoma Geological Survey Special Publication 2003-2, 87 p.

Bowker, K. A., 2005, The Barnett Shale play, Fort Worth Basin, *in* Cardott, B. J. (ed.), Unconventional energy resources in the southern Midcontinent, 2004 symposium: Oklahoma Geological Survey Circular 110 [this volume], p. 35.

Brown, A. A.; and Corrigan, J., 1997, Petroleum systems, Ardmore Basin and Arbuckle Mountains, Oklahoma: Dallas Geological Society Guidebook for Field Trip 2, American Association of Petroleum Geologists Annual Convention, 88 p.

Campbell, J. A.; Brown, D. P.; Cardott, B. J.; and Mycek-Memoli, A., 1993, Petroleum production from potentially fractured pre-Pennsylvanian reservoirs in Oklahoma, *in* Johnson, K. S.; and Campbell, J. A. (eds.), Petroleum-reservoir geology in the southern Midcontinent, 1991 symposium: Oklahoma Geological Survey Circular 95, p. 199–205.

Cardott, B. J., 1989, Thermal maturation of the Woodford Shale in the Anadarko Basin, *in* Johnson, K. S. (ed.), Anadarko Basin symposium, 1988: Oklahoma Geological Survey Circular 90, p. 32–46.

_____ 1994, Thermal maturity of surface samples from the frontal and central belts, Ouachita Mountains, Oklahoma, *in* Suneson, N. H.; and Hemish, L. A. (eds.), Geology and resources of the eastern Ouachita Mountains frontal belt and southeastern Arkoma Basin, Oklahoma: Oklahoma Geological Survey Guidebook 29, p. 271–276.

_____ 2001a, Thermal maturation of the Woodford Shale in south-central Oklahoma [abstract], *in* Johnson, K. S. (ed.), Silurian, Devonian, and Mississippian geology and petroleum in the southern Midcontinent, 1999 symposium: Oklahoma Geological Survey Circular 105, p. 170.

_____ 2001b, Thermal maturation of the Woodford Shale in eastern Oklahoma [abstract], *in* Johnson, K. S.; and Merriam, D. F. (eds.), Petroleum systems of sedimentary basins in the southern Midcontinent, 2000 symposium: Oklahoma Geological Survey Circular 106, p. 193.

_____ 2002a, Introduction to coal geology of Oklahoma, *in* Cardott, B. J. (compiler), Fourth annual Oklahoma coalbed-methane workshop: Oklahoma Geological Survey Open-File Report 9-2002, p. 34–55.

_____ 2002b, Coalbed-methane activity in Oklahoma, 2002 update, *in* Cardott, B. J. (compiler), Fourth annual Oklahoma coalbed-methane workshop: Oklahoma Geological Survey Open-File Report 9-2002, p. 56–82.

_____ 2005, Coalbed-methane activity in Oklahoma, 2004 update, *in* Cardott, B. J. (ed.), Unconventional energy resources in the southern Midcontinent, 2004 symposium: Oklahoma Geological Survey Circular 110 [this volume], p. 69–82.

Cardott, B. J.; and Chaplin, J. R., 1993, Guidebook for selected stops in the western Arbuckle Mountains, southern Oklahoma: Oklahoma Geological Survey Special Publication 93-3, 55 p.

Cardott, B. J.; Metcalf, W. J., III; and Ahern, J. L., 1990, Thermal maturation by vitrinite reflectance of Woodford Shale near Washita Valley fault, Arbuckle Mountains, plications of thermal maturity studies to energy exploration: Society of Economic Paleontologists and Mineralogists Rocky Mountain Section, p. 139–146.

Carr, J. L., III, 1987, The thermal maturity of the Chattanooga Formation along a transect from the Ozark Uplift to the Arkoma Basin: Oklahoma City Geological Society Shale Shaker, v. 38, p. 32–40.

Cassidy, H. M., 1968, Excello Shale, northeastern Oklahoma: clue to locating buried reefs: American Association of Petroleum Geologists Bulletin, v. 52, p. 295–312.

Comer, J. B., 1992, Organic geochemistry and paleogeography of Upper Devonian formations in Oklahoma and northwestern Arkansas, *in* Johnson, K. S.; and Cardott, B. J. (eds.), Source rocks in the southern Midcontinent, 1990 symposium: Oklahoma Geological Survey Circular 93, p. 70–93.

Curtis, J. B., 2002, Fractured shale-gas systems: American Association of Petroleum Geologists Bulletin, v. 86, p. 1921–1938.

Duncan, D. C.; and Swanson, V. E., 1965, Organic-rich shale of the United States and world land areas: U.S. Geological Survey Circular 523, 30 p.

Dyman, T. S.; Wyman, R. E.; Kuuskraa, V. A., Lewan, M. D.; and Cook, T. A., 2003, Deep natural gas resources: Natural Resources Research, v. 12, p. 41–56.

Dyni, J. R., 2000, Oil shale: American Association of Petroleum Geologists Energy Minerals Division web site. http://emd.aapg.org/technical_areas/oil_shale.cfm

_____ (ed.), 2003, Unconventional energy resources of North America: American Association of Petroleum Geologists Special Publication, Energy Minerals Division Poster.

Ece, O. I., 1987a, Stratigraphy, paleogeography and depositional environments of the upper middle Carboniferous (Desmoinesian) cyclothemic Excello black shale of the Midcontinent region, USA: Marine and Petroleum Geology, v. 4, p. 243–254.

_____ 1987b, Petrology of the Desmoinesian Excello black shale of the Midcontinent region of the United States: Clays and Clay Minerals, v. 35, p. 262–270.

_____ 1989, Organic maturation and paleoceanographic/paleogeographic implications of the Desmoinesian cyclothemic Excello black shale of the Midcontinent, USA: Oklahoma City Geological Society Shale Shaker, v. 39, p. 90–104.

EIA, 2003, Advance summary: U.S. crude oil, natural gas, and natural gas liquids reserves, 2002 annual report: Energy Information Administration, U.S. Department of Energy, DOE/EIA-0216(2002), 16 p. http://www.eia.doe.gov/oil_gas/fwd/adsum2002.html

_____ 2004, Renewable energy annual 2003: DOE/EIA-0603. http://www.eia.doe/cneaf/solar.renewables/page/rea_data/rea_sum.html

Elias, M. K.; and Branson, C. C., 1959, Type section of the Caney Shale: Oklahoma Geological Survey Circular 52, 24 p.

Faraj, B.; Williams, H.; Addison, G.; and McKinstry, B., 2004, Gas potential of selected shale formations in the western Canadian sedimentary basin: GasTIPS, v. 10, no. 1, p. 21–25.

GTI [Gas Technology Institute], 2000, United States fractured shale gas resource map: Distributed with GasTIPS, v. 6, no. 2.

_____ 2001, Tight gas resource map of the United States: Distributed with GasTIPS, v. 7, no. 2.

Harrison, W. E.; and Burchfield, M. R., 1987, Resource evaluation of selected tar-sand deposits in southern Oklahoma, *in* Meyers, R. F. (ed.), Exploration for heavy crude oil and natural bitumen: American Association of Petroleum Geologists Studies in Geology 25, p. 571–588.

Hatch, J. R.; and Levanthal, J. S., 1997, Early diagenetic partial oxidation or organic matter and sulfides in the middle Pennsylvanian (Desmoinesian) Excello Shale Member of the Fort Scott Limestone and equivalents, northern Midcontinent region, USA: Chemical Geology, v. 134, p. 215–235.

Hemish, L. A., 2002, Surface to subsurface correlation of methane-producing coal beds, northeast Oklahoma shelf: Oklahoma Geological Survey Special Publication 2002-2, 22 p.

Hendrick, S. J., 1992, Vitrinite reflectance and deep Arbuckle maturation at Wilburton field, Latimer County, Oklahoma, *in* Johnson, K. S.; and Cardott, B. J. (eds.), Source rocks in the southern Midcontinent, 1990 symposium: Oklahoma Geological Survey Circular 93, p. 176–184.

Henry, M. E.; and Finn, T. M., 2003, Evaluation of undiscovered natural gas in the Upper Cretaceous Ferron coal/Wasatch Plateau total petroleum system, Wasatch Plateau and Castle Valley, Utah: International Journal of Coal Geology, v. 56, p. 3–37.

Hill, D. G.; and Nelson, C. R., 2000, Gas productive fractured shales: an overview and update: GasTIPS, v. 6, no. 2, p. 4–13.

Hughes, T. W.; Meo, M.; Simonsen, T.; Stadler, S. J.; and Traurig, J., 2002, Developing Oklahoma wind-resource models and products: opportunities for energy diversification by the Oklahoma oil and gas industry: Oklahoma Geology Notes, v. 62, p. 132–142.

Hunt, J. M., 1979, Petroleum geochemistry and geology: W. H. Freeman and Company, San Francisco, 617 p.

Hutton, A. C., 1995, Organic petrography of oil shales, *in* Snape, C. (ed.), Composition, geochemistry and conversion of oil shales: Kluwer Academic Publishers, Boston, NATO ASI Series C, Mathematical and Physical Sciences, v. 455, p. 17–33.

Hycrude, 1986, Beneficiation-hydroretorting of U.S. oil shales: Hycrude Corporation, Chicago, Annual status report, variously paginated, U.S. Department of Energy Grant No. DE-FG21-85LC111066.

James, G. W.; and Baker, D. R., 1972, Organic geochemistry of a Pennsylvanian black shale (Excello) in the Midcontinent and the Illinois Basin, *in* Kellogg, J. A. (ed.), Short papers on research in 1971: Kansas Geological Survey Bulletin 204, pt. 1, p. 3–10.

Johnson, K. S.; and Cardott, B. J., 1992, Geologic framework and hydrocarbon source rocks of Oklahoma, *in* Johnson, K. S.; and Cardott, B. J. (eds.), Source rocks in the southern Midcontinent, 1990 symposium: Oklahoma Geological Survey Circular 93, p. 21–37.

Johnson, K. S.; Burchfield, M. R.; and Harrison, W. E., 1984, Guidebook for Arbuckle Mountain field trip, southern Oklahoma: Oklahoma Geological Survey Special Publication 84-1, 21 p.

Jordan, L., 1964, Petroleum-impregnated rocks and asphaltite deposits in Oklahoma: Oklahoma Geological Survey Map GM-8, 16-page text, scale 1:750,000.

Kuuskraa, V. A.; and Bank, G. C., 2003, Gas from tight sands, shales a growing share of U.S. supply: Oil & Gas Journal, v. 101.47, p. 34–36, 38, 40–43.

Landis, E. R., 1962, Uranium and other trace elements in

Devonian and Mississippian black shales in the central Midcontinent area: U.S. Geological Survey Bulletin 1107-E, p. 289–336.

Law, B. E., 2002, Basin-centered gas systems: American Association of Petroleum Geologists Bulletin, v. 86, p. 1891–1919.

Law, B. E.; and Curtis, J. B., 2002, Introduction to unconventional petroleum systems: American Association of Petroleum Geologists Bulletin, v. 86, p. 1851–1852.

Limerick, S. H., 2003, Coalbed methane in the U.S.: Energy Information Administration, U.S. Department of Energy, 2 maps. http://www.eia.doe.gov/pub/oil_gas/natural_gas/analysis_publications/maps/maps.htm#Top

Martini, A. M.; Walter, L. M.; Ku, T. C. W.; Budai, J. M.; McIntosh, M. C.; and Schoell, M., 2003, Microbial production and modification of gases in sedimentary basins: a geochemical case study from a Devonian shale gas play, Michigan Basin: American Association of Petroleum Geologists Bulletin, v. 87, p. 1355–1375.

Meyer, R. F.; and De Witt, W., Jr., 1990, Definition and world resources of natural bitumens: U.S. Geological Survey Bulletin 1944, 14 p.

Monaghan, P. T., 1985, The stratigraphy of the Mississippian–Pennsylvanian shale sequence of southern Oklahoma: Baylor University, Waco, Texas, unpublished B.S. thesis, 52 p.

Moritis, G., 2004, Suncor's George: oil sands a long-life, low-risk resource: Oil & Gas Journal, v. 102.11, p. 37, 38.

NaturalGas.org, 2004, Unconventional natural gas resources: http://www.naturalgas.org/overview/unconvent_ng_resource.asp

Nelson, C. R.; and Pratt, T. J., 2001, In coalbed gas plays, reservoir variables key to success: American Oil & Gas Reporter, v. 44, no. 3, p. 78–87.

Nielsen, D., 2003, Geothermal energy, *in* Dyni, J. R. (ed.), Unconventional energy resources of North America: American Association of Petroleum Geologists Special Publication, Energy Minerals Division Poster.

Northcutt, R. A.; Johnson, K. S.; and Hinshaw, G. C., 2001, Geology and petroleum reservoirs in Silurian, Devonian, and Mississippian rocks in Oklahoma, *in* Johnson, K. S. (ed.), Silurian, Devonian, and Mississippian geology and petroleum in the southern Midcontinent, 1999 symposium: Oklahoma Geological Survey Circular 105, p. 1–15.

Nowacki, P. (ed.), 1981, Oil shale technical data handbook: Noyes Data Corporation, Park Ridge, New Jersey, 309 p.

Peters, K. E.; and Cassa, M. R., 1994, Applied source rock geochemistry, *in* Magoon, L. B.; and Dow, W. G. (eds.), The petroleum system—from source to trap: American Association of Petroleum Geologists Memoir 60, p. 93–120.

Popov, M. A.; Nuccio, V. F.; Dyman, T. S.; Gognat, T. A.; Johnson, R. C.; Schmoker, J. W.; Wilson, M. S.; and Bartberger, C., 2001, Basin-centered gas systems of the U.S.: U.S. Geological Survey Open-File Report 01-135, Version 1.0 (CD).

Prouty, J. L., 2001, Tight gas in the spotlight: GasTIPS, v. 7, no. 2, p. 4–10.

Roberts, C. T.; and Mitterer, R. M., 1992, Laminated black shale–bedded chert cyclicity in the Woodford Formation, southern Oklahoma, *in* Johnson, K. S.; and Cardott, B. J. (eds.), Source rocks in the southern Midcontinent, 1990 symposium: Oklahoma Geological Survey Circular 93, p. 330–336.

Rogers, J. D.; Lambert, S. W.; and Wolhart, S., 2004, Benchmarking deep drilling and completion technologies: GasTIPS, v. 10, no. 2, p. 5–8.

Rottenfusser, B., 2003, Oil sands, *in* Dyni, J. R. (ed.), Unconventional energy resources of North America: American Association of Petroleum Geologists Special Publication, Energy Minerals Division Poster.

Russell, P. L., 1990, Oil shales of the world, their origin, occurrence and exploitation: Pergamon Press, New York City, 753 p.

Sanderson, G. A.; and Berggren, L. W., 1998, White paper: update on application of §29 tax credit to coal seam gas: U.S. Environmental Protection Agency, 16 p. http://www.epa.gov/coalbed/clibrary/creports/natural_gas.htm

Schmoker, J. W., 1999, U.S. Geological Survey assessment model for continuous (unconventional) oil and gas accumulations—the "FORSPAN" model: U.S. Geological Survey Bulletin 2168, 9 p.

Schmoker, J. W.; Fouch, T. D.; and Charpentier, R. R., 1996, Gas in the Uinta Basin, Utah—resources in continuous accumulations: The Mountain Geologist, v. 33, no. 4, p. 95–104.

Sutherland, P. K., 1981, Mississippian and lower Pennsylvanian stratigraphy in Oklahoma: Oklahoma Geology Notes, v. 41, p. 3–22.

Swanson, V. E., 1960, Oil yield and uranium content of black shales: U.S. Geological Survey Professional Paper 356-A, 44 p.

Tissot, B.; and Welte, D. H., 1984, Petroleum formation and occurrence [2nd edition]: Springer-Verlag, New York City, 699 p.

U.S. Geological Survey, 1995, 1995 National assessment of United States oil and gas resources: U.S. Geological Survey Circular 1118, 20 p.

Walker, P. E. G., 1986, A regional study of the diagenetic and geochemical character of the Pennsylvanian Morrow Formation, Anadarko Basin, Oklahoma: Oklahoma State University, Stillwater, unpublished M.S. thesis, 156 p.

Wavrek, D. A., 1992, Characterization of oil types in the Ardmore and Marietta Basins, southern Oklahoma aulacogen, *in* Johnson, K. S.; and Cardott, B. J. (eds.), Source rocks in the southern Midcontinent, 1990 symposium: Oklahoma Geological Survey Circular 93, p.185–195.

Weaver, C. E., 1958, Geologic interpretation of argillaceous sediments; Part 2—Clay petrology of Upper Mississippian–Lower Pennsylvanian sediments of central United States: American Association of Petroleum Geologists Bulletin, v. 42, p. 272–309.

Weber, J. L., 1994, A geochemical study of crude oils and possible source rocks in the Ouachita tectonic province and nearby areas, southeast Oklahoma: Oklahoma Geological Survey Special Publication 94-2, 32 p.

Wenger, L. M.; Baker, D. R.; Chung, H. M.; and McCulloh, T. H., 1988, Environmental control of carbon isotope variations in Pennsylvanian black-shale sequences, Midcontinent, U.S.A.: Organic Geochemistry, v. 13, p. 765–771.

Williams, B., 2003a, Heavy hydrocarbons playing key role in peak-oil debate, future energy supply: Oil & Gas Journal, v. 101.29, p. 20–27.

______ 2003b, Peak-oil, global warming concerns opening new window of opportunity for alternative energy sources: Oil & Gas Journal, v. 101.32, p. 18–20, 22–28.

Reversing the Trend: The Impact of Unconventional Energy Development on Drilling Activity and Production in Oklahoma

Jim Puckette
Oklahoma State University
Stillwater, Oklahoma

ABSTRACT.—Unconventional energy development has stimulated increased drilling activity across the Midcontinent region. In some areas of Oklahoma, drilling for unconventional energy sources has reversed long-established production declines. In others, increased drilling has not resulted in a positive response in oil and gas production.

Exploration for coalbed methane (CBM) and shallow "hot-shale" gas has profoundly affected drilling activity and gas production on the northeast Oklahoma Platform. Nowata County, which was an oil-dominated area since pre-statehood, saw the number of gas wells increase from 8 in 1996 to 50 in 2000. This 6-fold increase in the number of gas wells was accompanied by an increase of gas sales from 0.6 billion cubic feet (Bcf) in 1996 to in excess of 7 Bcf in 2002. Prior to the onset of CBM activity, gas sales in Nowata County had declined steadily from approximately 0.8 Bcf/yr in 1986 to 0.4 Bcf in 1995. Significant increases in gas production also are evident in neighboring Washington (6-fold increase from 1995 to 2002), Rogers (4-fold increase from 1997 to 2002) and Craig Counties (14-fold increase from 1998 to 2002).

CBM development in the Arkoma Basin has increased drilling activity without generating the salient reversals in decline curves that are evident for counties to the north on the platform. Haskell County, which saw gas-well–drilling activity increase from 23 wells in 1998 to 108 wells in 2001, experienced a 5 to 8 Bcf increase in yearly gas production over the same time period. Pittsburgh County saw gas-well drilling increase from 53 wells in 1997 to 172 in 2001. Concurrently, gas production continued declining until 1999, when the curve flattened and began rising. By 2001 the curve had posted a modest 6 Bcf gain. Ascertaining the actual impact of CBM development is difficult in these counties because they were producing large volumes of conventional gas when CBM production came on line. Part of the gains from CBM production may be masked by the decline in production from conventional gas wells. However, Le Flore County, which produced approximately 20–30 Bcf per year prior to the CBM surge, has seen no significant increase in gas production even though drilling activity increased from 18 wells in 1999 to 76 in 2001.

The unconventional dewatering play in north-central Oklahoma has dramatically impacted production in several counties. Lincoln County, where the Hunton Group dewatering play began, saw drilling increase from 17 wells in 1997 to 97 wells in 2000. The impact of this activity is evident as oil production increased from 1.3 million barrels of oil (MMbo) in 1997 to 3.1 MMbo in 2001. Concurrently, gas production increased from 8.9 Bcf to 25.8 Bcf. From 1997 to 2001, neighboring Logan County saw its drilling activity increase from 32 to 71 wells, oil production increase from 1.5 to 3.1 MMbo per year, and gas production increase from 15.4 to 26.9 Bcf per year.

Development drilling for unconventional tight gas sandstones in the Red Fork interval of the Strong City District has stimulated drilling activity in the Anadarko Basin. From 1999 to 2002, drilling activity in Roger Mills County increased from 40 wells to 87 wells. However, during the same time period, gas production steadily declined from 133 Bcf in 1999 to 124 Bcf in 2002.

Puckette, Jim, 2005, Reversing the trend: the impact of unconventional energy development on drilling activity and production in Oklahoma, *in* Cardott, B. J. (ed.), Unconventional energy resources in the southern Midcontinent, 2004 symposium: Oklahoma Geological Survey Circular 110, p. 19–27.

INTRODUCTION

Production statistics for the oil- and gas-producing counties in Oklahoma were analyzed to determine the impact of unconventional plays on the volumes of oil and gas produced in the State. Production- and well-completion data provided by the Oklahoma Corporation Commission (2003) were tabulated for each county by year. The number of wells drilled, types of completions, and the volumes of produced oil, condensate, dry gas, and associated gas were comparatively analyzed. To simplify the analysis, volumes for oil and condensate were summed. Likewise, dry-gas and associated-gas volumes were combined.

Three types of unconventional plays were analyzed: CBM, tight-gas sandstone, and high-volume water production. All three involve the application of technology to reservoirs with unique architectural and/or fluid characteristics. Reservoir characteristics are not the focus of this paper and will only be discussed generally. The locations of the unconventional plays and the counties examined in this study are shown in Figure 1.

COALBED METHANE

The impact of CBM development was analyzed for two areas: (1) the Cherokee Basin in northeastern Oklahoma and (2) the Arkoma Basin in southeastern Oklahoma. Drilling and production data were not examined for the portions of these basins in the states of Kansas and Arkansas, respectively.

Cherokee Basin

Drilling and production data were analyzed for five counties located in the Cherokee Basin (Fig. 1). Several trends were readily apparent. The first was the shift in the ratios of oil, gas, and dry hole completions. With the onset of CBM activity, the number of gas completions

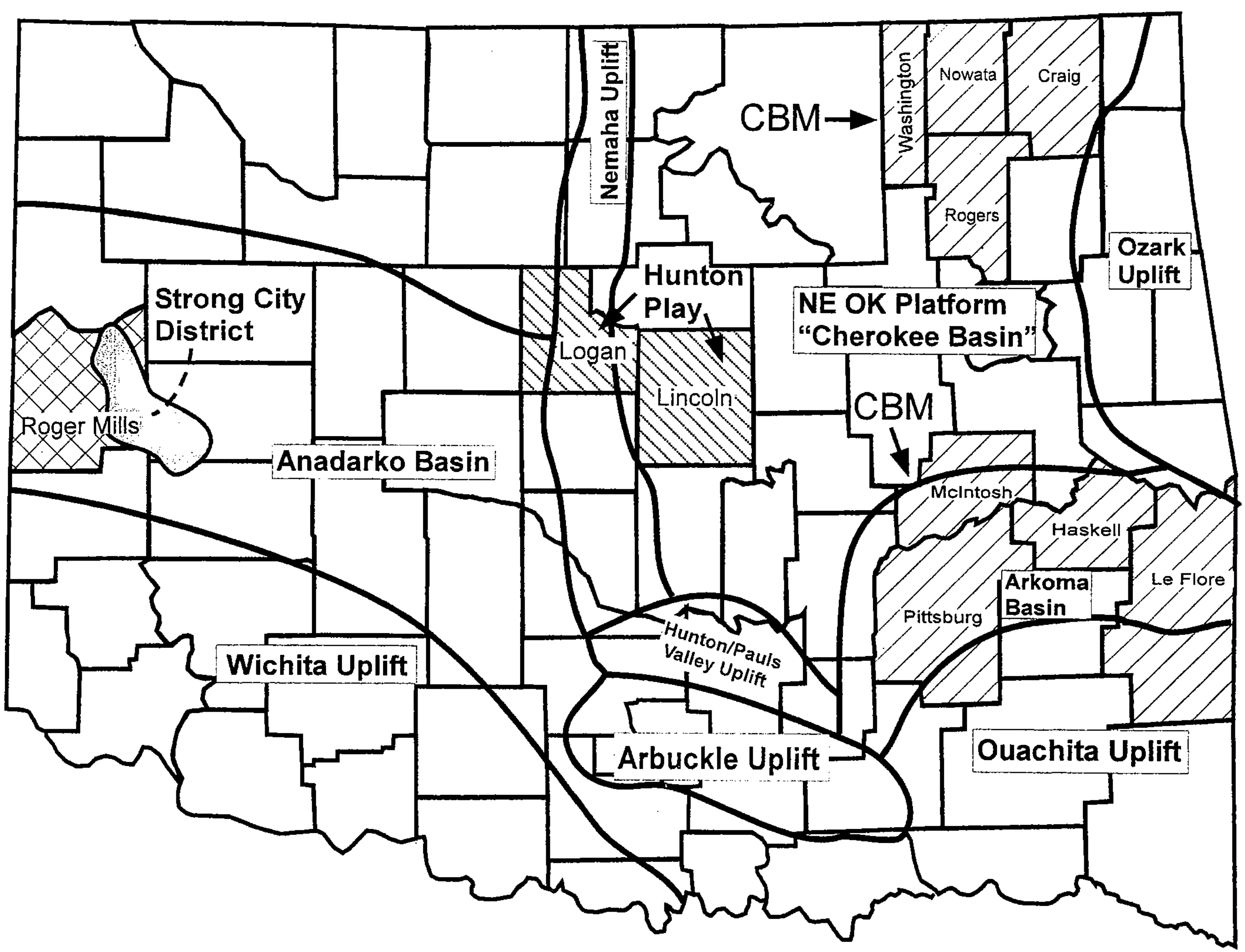


Figure 1. Generalized location of unconventional plays within the regional tectonic framework. Counties from which production data are included in this study are identified by name and indicated by hachure or cross-hachure patterns. CBM: coalbed methane producing areas. Hunton Play: dewatering play in the Hunton Group. Strong City District: location of tight-gas-sandstone development in the Red Fork interval.

increases, the number of oil completions declines, and the number of dry hole completions is drastically reduced. These trends will be discussed for each county. The second trend is the increase in gas production. All counties with complete data sets and active CBM development have marked increases in gas production.

The Cherokee Basin contains multiple coal seams and gas-bearing, dark-colored "hot" shales in the Pennsylvanian Desmoinesian Series. It is a common industry practice to complete CBM wells by perforating several coal seams and gas-bearing shales in the same well bore and commingling the produced gas (Huhnke, 2004).

Nowata County

CBM activity has transformed this traditional oil-producing county into a gas-dominated one. The number of oil wells completed per annum in Nowata County declined from a high of 226 in 1983 to 1 in 2002. The number of gas wells completed also declined from a high of 42 in 1984 to 1 in 1994. With the onset of CBM activity in 1995, the number of gas wells began to rise. Between 1996 and 2002, 235 gas wells were completed, which is more than were completed in the previous 13 years (142). Concurrently, the number of dry holes completed dropped significantly. Dry holes, which were 16% of all wells drilled during the period from 1983 through 1994, averaged only 9% for the time period between 1995 and 2002. Remarkably, the number of actively producing gas wells, which increased from 52 in 1998 to 580 in 2002, now exceeds the number of active oil wells in Nowata County, which declined from 352 to 348 over the same time period. The completion activity for Nowata County is shown in Figure 2.

The cumulative oil- and gas-production volumes reflect the changes seen in the trends of the number of well completions. Oil production declined steadily at a 6% per annum rate from 1993 through 2002. Production for 1993 exceeded 395,000 barrels, whereas production for 2002 was only slightly more than 157,000 barrels. In contrast, gas production increased from 0.283 billion cubic feet (Bcf) in 1993 to 0.627 Bcf in 1996 and 7.248 Bcf in 2002. As additional CBM wells came on production between 1996 and 2002, the increase in gas production exceeded 120% per year. These changes are illustrated in the production graphs shown on Figure 2.

Craig County

Drilling activity and production statistics for Craig County reflect changes in trends that are similar to those seen for Nowata County. Craig County produces much less oil and gas than Nowata County. Consequently, the impact of CBM on cumulative production percentages is magnified.

Well-completion statistics for Craig County are shown in Figure 3. The number of oil wells completed in Craig County is small and ranges from a high of 6 in 1983 to a low of 0 for several years, including 2002. Following a dramatic increase in the total gas wells completed in 1983, the number declined from 4 in 1984 to 0 in 1986. The number of gas completions stayed below 3 per year until 2001, when 19 CBM wells were drilled. Twenty-five CBM gas wells were completed in 2002. Two dry holes were reported in 2001, whereas none were reported for 2002.

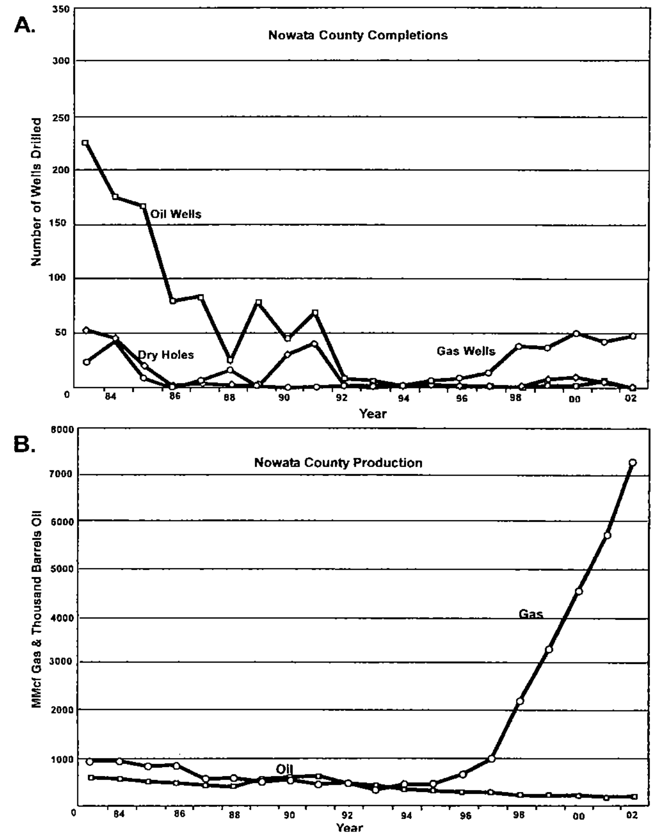


Figure 2. Graphs of well-completion activity and yearly oil and gas production, Nowata County, Oklahoma, that illustrate the impact of CBM activity on the number of completions and oil and gas production. The CBM play is characterized by a high success rate (few dry completions) and a dramatic increase in gas production (10-fold increase between 1996 and 2002). Oil production is unaffected by CBM activity. (A) Yearly well-completion activity, 1983–2002. (B) Yearly oil and gas production, 1983–2002; MMcf = million cubic feet.

The cumulative oil- and gas-production volumes for Craig County reflect these changes. Maximum oil production occurred in 1991 when 14,000 barrels were produced. By 2002, production had declined to slightly more than 600 barrels. In contrast, gas production, which was negligible for many years prior to the onset of CBM activity, increased from 0.069 Bcf in 2001 to 0.825 Bcf in 2002, or an increase of 1,600%. These trends are illustrated in the graphs of production shown on Figure 3.

Rogers County

The trends of drilling activity and production for Rogers County differ slightly from those for Nowata and Craig Counties in that Rogers County has more conventional gas production. However, the impact of CBM on

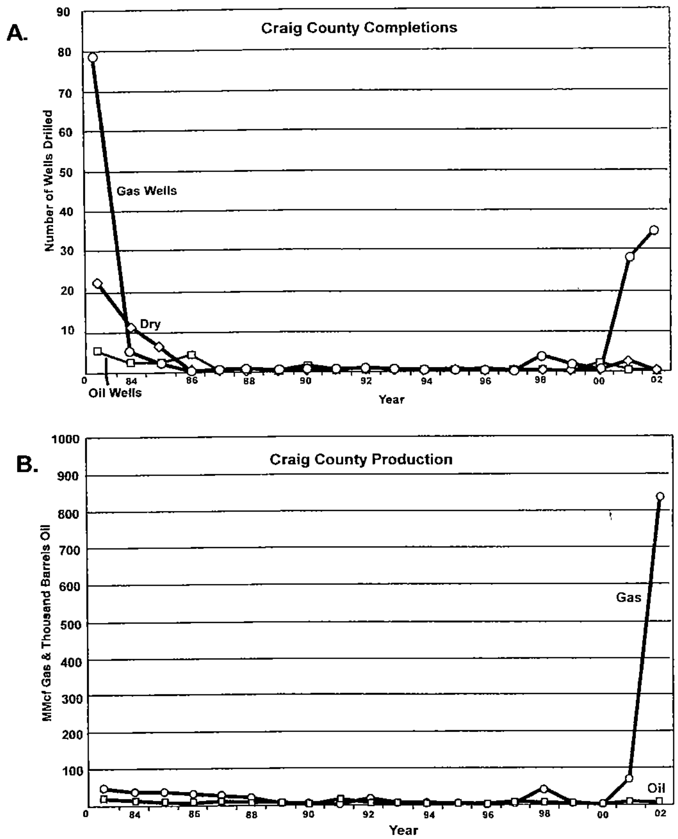


Figure 3. Graphs of well-completion activity and yearly oil and gas production for Craig County, Oklahoma. CBM activity created a dramatic increase in gas production for this low-production volume county. (A) Yearly well-completion activity, 1983–2002. (B) Yearly oil and gas production, 1983–2002; MMcf = million cubic feet.

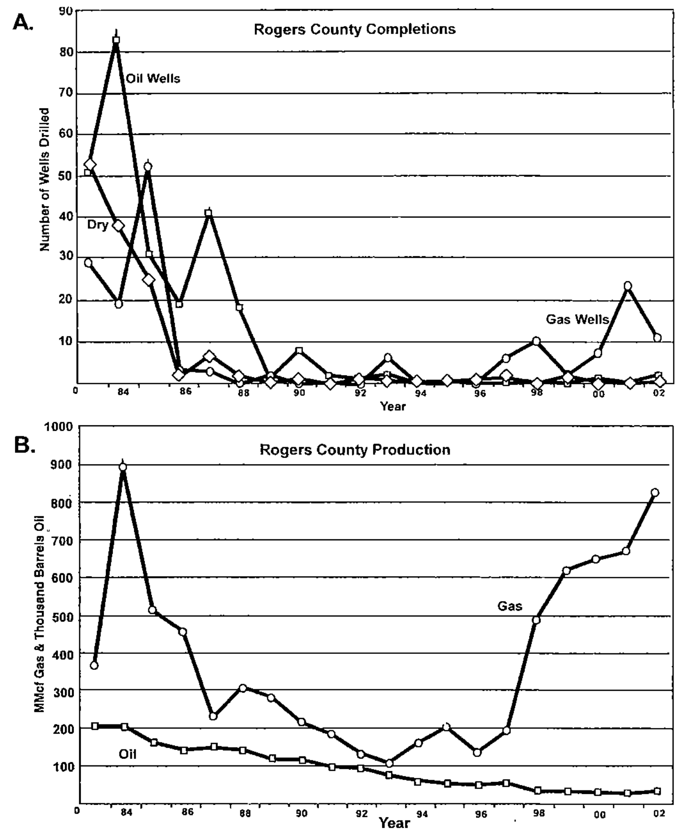


Figure 4. Graphs of well-completion activity and yearly oil and gas production for Rogers County, Oklahoma. CBM activity created a dramatic 400% increase in gas production between 1997 and 2002 without affecting the declining oil volumes. (A) Yearly well-completion activity, 1983–2002. (B) Yearly oil and gas production, 1983–2002; MMcf = million cubic feet.

gas production in Rogers County is still striking. Well-completion data for Rogers County are shown in Figure 4. The number of oil wells completed in Rogers County declined from a high of 83 in 1984 to 2 in 2002. From 1985 to 1996, the number of gas wells completed declined from 52 to 0. With the initiation of CBM activity, the number of gas completions began to increase. Gas completions peaked in 2001 at 23 and decreased to 11 in 2002. The number of dry holes, which peaked at 54 or 40% of all wells completed in 1983, declined for the 14-year period from 1985 through 1999. The number of dry completions was 2 for 1999 and 0 in 2000, where it remains.

Cumulative oil- and gas-production volumes reflect the changes seen in the trends of the numbers of well completions. Oil production declined from more than 200,000 barrels in 1983 to slightly more than 33,000 barrels in 2002. Gas production declined from an early high 0.88 Bcf in 1984 to 0.135 Bcf in 1996, when the reversal of decline in response to CBM activity began. From 1997 to 2002, gas production increased from 0.193 Bcf to 0.82 Bcf or an increase of 420%. These changes are illustrated on the production graphs shown on Figure 4.

Washington County

Washington County is similar to Rogers County in that it is not dominated by oil production. Figure 5 illustrates the impact of CBM development on drilling activity and oil and gas production. The number of oil wells completed in Washington County declined from a high of 330 in 1984 to 1 in 2002. The number of gas wells completed declined from 48 in 1983 to 3 in 1994. With the initiation of CBM activity in 1995, an average of 10 gas wells was completed each year through 2000. In 2001, the number increased to 31. The percentage of dry holes, which was 24% in 1983, was approximately 10% for 2001 and 2002.

The cumulative oil- and gas-production volumes for Washington County reflect the trends that are evident on the graphs of well completions. Oil production declined steadily from a high in 1984, when it exceeded 1 million barrels, to approximately 250,000 barrels in 2002. Gas production decreased from 1983 until 1993, when it began to increase. Production increased rapidly in 1996 to 1.5 Bcf as CBM wells went on production. In the year 2000, gas production reached 2.7 Bcf. By 2002, gas production exceeded 4.6 Bcf annually or an increase of 650% over a 7-year period (Fig. 5).

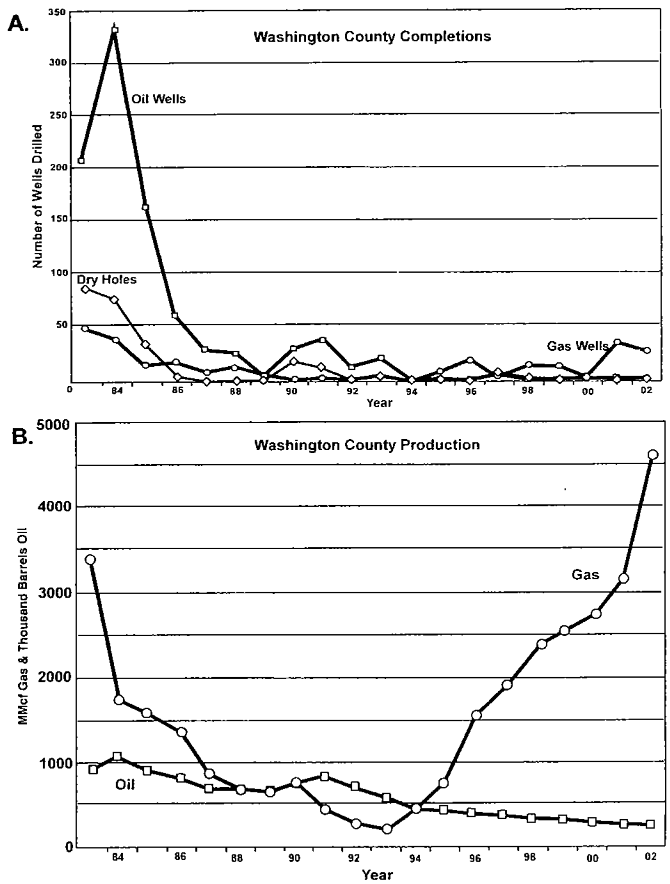


Figure 5. Graphs of well-completion activity and yearly oil and gas production for Washington County, Oklahoma. CBM activity resulted in 600% increase in gas production, whereas oil production remains unaffected and continues to decline. (A) Yearly well-completion activity, 1983–2002. (B) Yearly oil and gas production, 1983–2002; MMcf = million cubic feet.

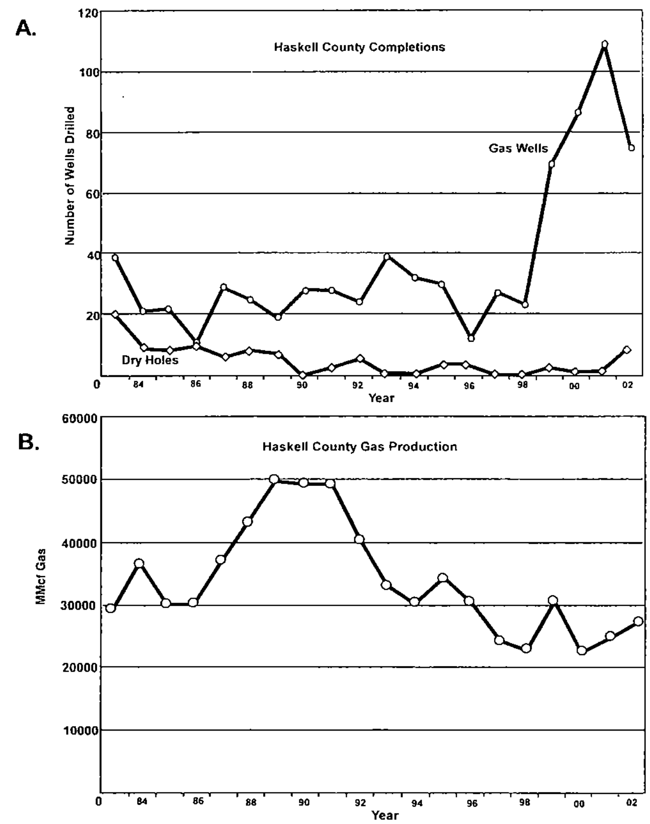


Figure 6. Graphs of well-completion activity and yearly gas production for Haskell County, Oklahoma. CBM activity is reflected in the dramatic increase in gas-well completions. CBM production does not impact the production graph in an obvious manner because of high-volume, conventional base-gas production. (A) Yearly well-completion activity, 1983–2002. (B) Yearly oil and gas production, 1983–2002; MMcf = million cubic feet.

Arkoma Basin

CBM development in the Arkoma Basin is centered on the Hartshorne coal of the Desmoinesian (Pennsylvanian) Krebs Group. The Hartshorne coal is widespread and a target for development over a large area of southeastern Oklahoma, including Pittsburg, Latimer, McIntosh, Haskell, and Le Flore Counties (Fig. 1). The coal consists of a single seam north of the "coal split line" and two seams to the south (Godwin, 2004). CBM development is concentrated in the single seam; most Hartshorne coal completions are single-zone vertical or horizontal wells.

Identifying the contribution of Hartshorne CBM wells to production on a countywide basis can be difficult. A number of the counties with active Hartshorne CBM development have a high base production from conventional reservoirs. In these cases, production volumes were calculated using data from commercial sources.

Haskell County

An examination of the production-decline curve for Haskell County illustrates the difficulty in identifying the Hartshorne CBM contribution to gas production for those counties with a high-volume, conventional-type base production. With the onset of CBM development, the number of gas wells drilled and completed in Haskell County increased dramatically (Fig. 6). The number of gas completions tripled from 23 in 1998 to 69 in 1999. Over the 2-year period of 2000 and 2001, the number of gas completions increased another 150%. Completions peaked in 2001, when 108 gas wells and only 1 dry hole were completed. The decline in the number of gas completions in 2002 may be the result of a change in drilling techniques. Improvements in drilling technology have resulted in the drilling of an increased number of horizontal wellbores to produce gas from the thin Hartshorne coal seam. This practice reduces the total number of CBM wells drilled, but increases the volume of gas produced per well.

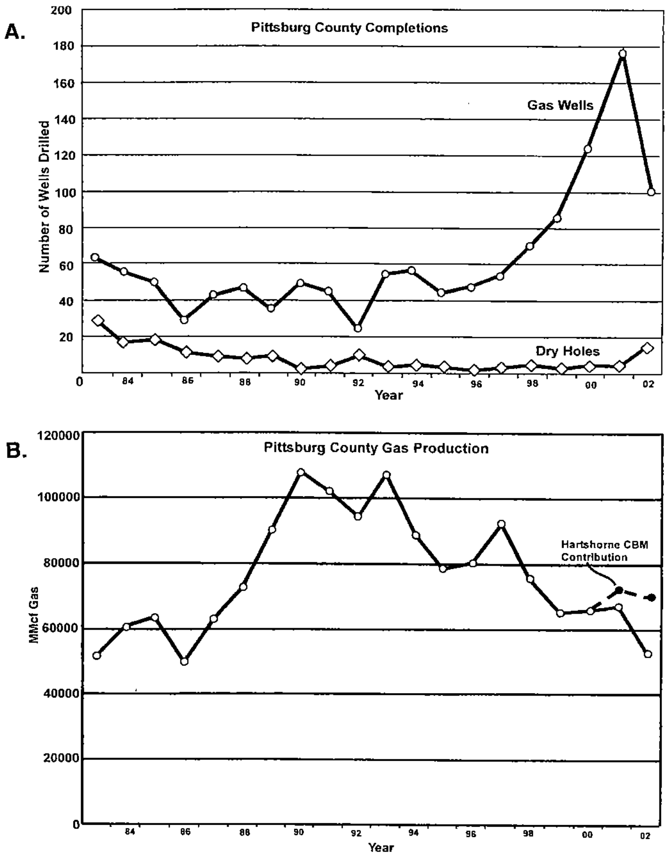


Figure 7. Graphs of well-completion activity and yearly gas production for Pittsburg County, Oklahoma. CBM activity is reflected in the dramatic increase in gas-well completions. CBM production is separated from the total conventional base-gas production to illustrate its contribution, which is approximately 15 Bcf in 2002. (A) Yearly well-completion activity, 1983–2002. (B) Yearly oil and gas production, 1983–2002; MMcf = million cubic feet.

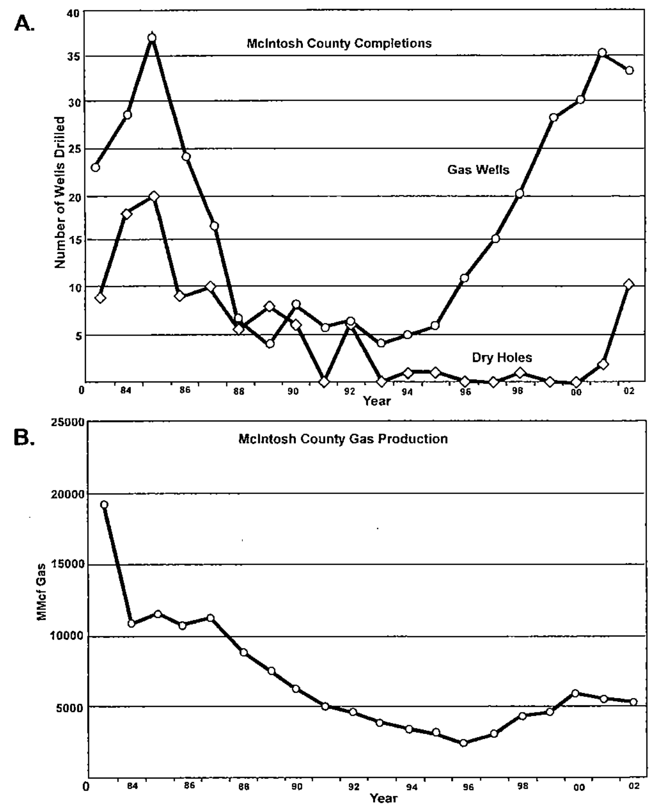


Figure 8. Graphs of well-completion activity and yearly gas production for McIntosh County, Oklahoma. CBM activity is reflected in the increase in gas-well completions and more than 200% increase in gas volume between 1996 and 2000. CBM production is reflected in the production graph because of the lower conventional base-gas production. (A) Yearly well-completion activity, 1983–2002. (B) Yearly oil and gas production, 1983–2002; MMcf = million cubic feet.

CBM development is making an impact on gas production for Haskell County. However, the percentage increase is modest compared to counties with low-volume, conventional gas production. Production for Haskell County exceeded 20 Bcf in both 1997 and 1998. The production graph (Fig. 6) indicates the production curve reached a minimum value in 1998, when per annum production began to increase. Whereas the total production volumes have increased from 22.4 Bcf for 1998 to 26.6 Bcf for 2002, the actual contribution from Hartshorne CBM is approximately 8–10 Bcf per year.

Pittsburg County

Production data for Pittsburg County were analyzed to determine the actual contribution of Hartshorne CBM to total production. Completion data (Fig. 7) illustrate the impact of CBM development on drilling activity. With the onset of CBM drilling in 1997, the number of gas wells drilled began to increase. In 1998, the number of gas completions increased 25% over 1997. Between 1999 and 2000, the number of completions increased 30% from 86 to 123. In 2001, the number of gas completions increased another 28% to 172. Concurrently, the percentage of dry holes declined to around 2% per year by 2001. The decrease in the total number of gas wells drilled in 2002 may be, in part, the result of the shift to increased horizontal drilling.

The graph of cumulative gas production (Fig. 7) does not suggest a change in slope in response to Hartshorne CBM production. However, analysis of commercially available production data (IHS Energy, 2003) indicates that approximately 15 Bcf of the total 69.6 Bcf produced in 2002 was from the Hartshorne coal.

McIntosh County

The onset of Hartshorne CBM activity is readily apparent on the graph of number of well completions in McIntosh County. The number of gas completions increased from less than 10 in 1995 to 35 in 2001. As the conventional production base in McIntosh County is relatively small, the impact of Hartshorne CBM production is very apparent on the graph of gas production (Fig. 8). In 1996, gas production for McIntosh County was 2.4 Bcf. CBM activity resulted in increased volumes each year from 1997 to 2000, when gas production peaked at 6.2 Bcf.

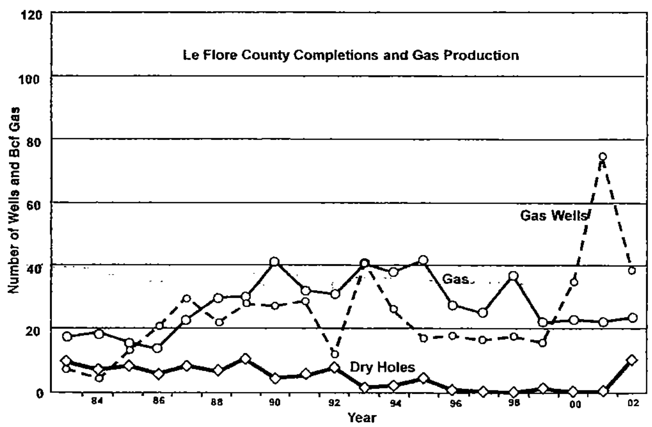


Figure 9. Graph of well-completion activity and yearly gas production for Le Flore County, Oklahoma. CBM activity is reflected by an increase in gas-well completions but does not generate an obvious response on the production curve. (A) Yearly well-completion activity, 1983–2002. (B) Yearly oil and gas production, 1983–2002. Bcf = billion cubic feet.

Le Flore County

Le Flore County is an enigma in that completion data indicate a vigorous CBM drilling program that did not produce a response in reported production (Fig. 9). Gas-well completions in Le Flore County increased from 1983 to 1993, when 42 wells were completed. Activity declined until 1999, when only 17 gas-well completions were reported. Activity escalated in 1999 and the number of completions doubled in 2000. In 2001, the number of completions reached to 75, a 440% increase from 1999. Only one dry hole was reported for the year 2001.

Reported gas-production volumes do not reflect the increased completion activity. Between 1999 and 2001, gas production remained relatively unchanged at approximately 22–24 Bcf per year (Fig. 9). This lack of response to CBM activity as expressed by the gas-production curve may be the result of several factors. One is limited Hartshorne CBM contribution resulting from a lack of gas-gathering infrastructure. Another is a delay in reporting resulting from record keeping or accounting procedures.

TIGHT-GAS SANDSTONE

Designated tight-gas-sandstone reservoirs are another important unconventional energy source. The most actively drilled tight-gas sandstone in the State is the sprawling Strong City District in the Anadarko Basin, western Oklahoma (Fig. 1). Between 1990 and 2002, more than 700 wells were drilled in the district, which is an assemblage of smaller fields that produce gas trapped in the Desmoinesian Red Fork sandstone submarine-fan complex (Puckette and Al-Shaieb, 2002). Most of the Strong City district is located in Roger Mills County; completion and production data for the county were used to analyze the impact of drilling activity on production.

Development drilling and well completions have remained relatively steady in Roger Mills County over the past 13 years (Fig. 10). From 1990 to 2000, an average of 56 wells were drilled each year. The number of gas completions increased to 79 in 2001, 74 gas wells were completed in 2002.

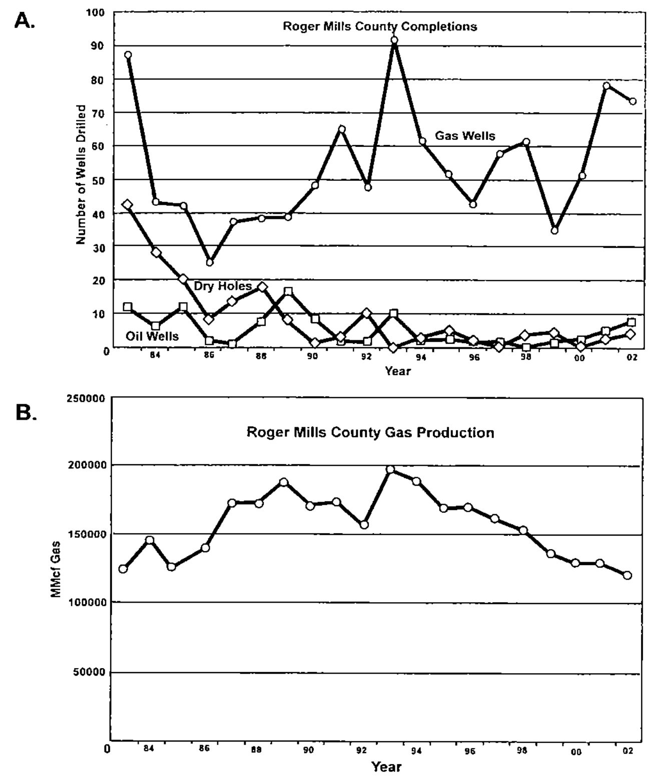


Figure 10. Graphs of well-completion activity and yearly gas production for Roger Mills County, Oklahoma. Development drilling for the Red Fork tight gas sandstone in the Strong City District has failed to produce a noticeable response on the production curve. (A) Yearly well-completion activity, 1983–2002. (B) Yearly oil and gas production, 1983–2002; MMcf = million cubic feet.

Gas-production data for Roger Mills County does not reflect a marked increase in production in response to the drilling activity. The graph of cumulative gas production (Fig. 10) indicates a steady decline for the county from 1993 to 2002. A flattening of the decline curve beginning in 1999 is the only suggestion that production volumes are responding to the increased number of completions.

HUNTON GROUP DEWATERING

An important unconventional energy source is the Ordovician–Silurian–Devonian Hunton Group in north-central Oklahoma, which is being produced using high-fluid-volume production techniques, called dewatering or water mining. The Hunton dewatering project, which was initiated in the Carney area of Lincoln County, has expanded to parts of Logan, Payne, Pottawatomie, and Seminole Counties (Fig. 1). The reservoirs in Lincoln, Logan, and Payne Counties are restricted to the Chimneyhill Subgroup of the Hunton Group. The carbonates

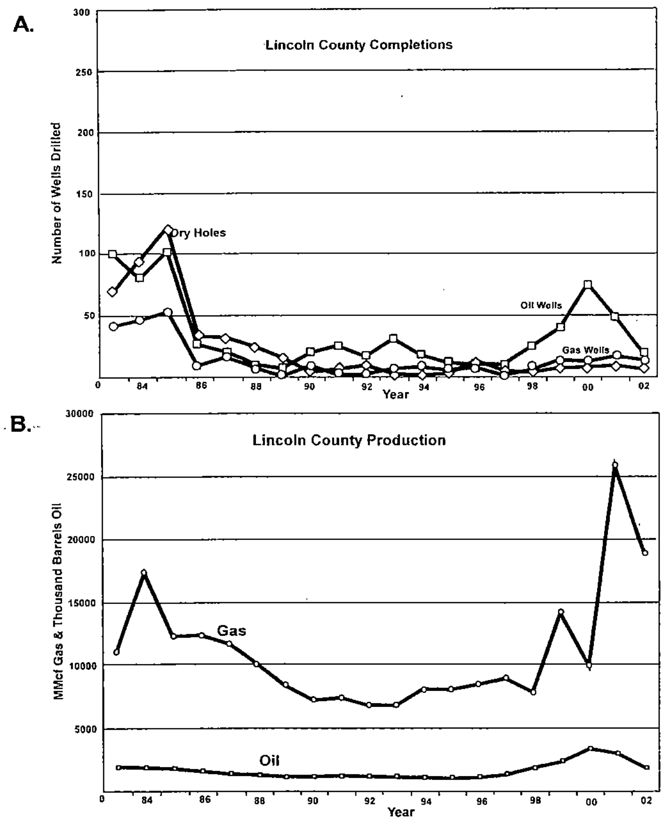


Figure 11. Graphs of well-completion activity and yearly gas production for Lincoln County, Oklahoma. Dewatering of the Hunton Group in the Carney area generated a surge in oil and gas completions, whereas the number of dry holes remained low. Hunton production generated a 330% increase in gas production between 1998 and 2001 and a 175% increase in oil production between 1998 and 2000. (A) Yearly well-completion activity, 1983–2002. (B) Yearly oil and gas production, 1983–2002; MMcf = million cubic feet.

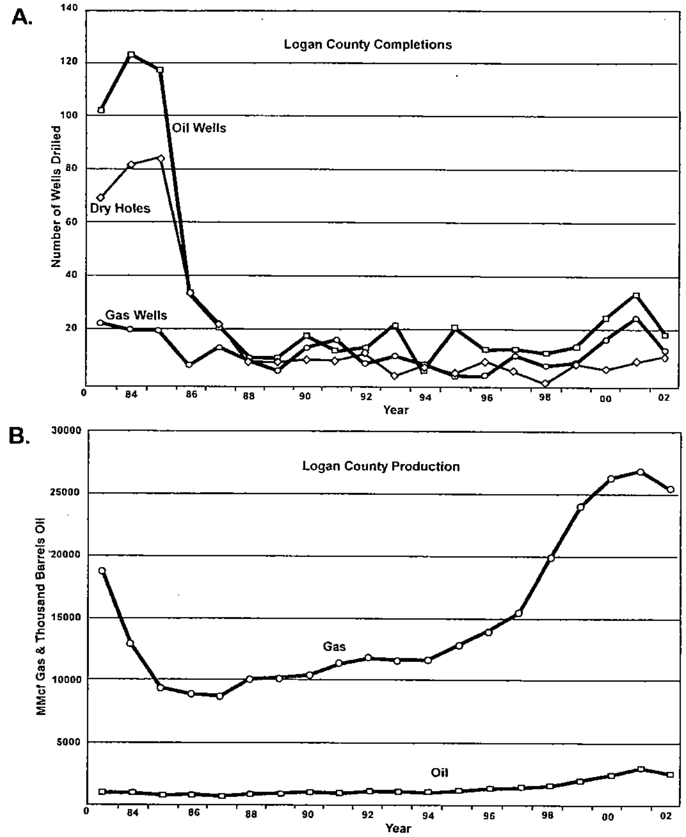


Figure 12. Graphs of well-completion activity and yearly gas production for Logan County, Oklahoma. Dewatering of the Hunton Group generated a sharp increase in oil and gas completions and production between 1999 and 2001. (A) Yearly well-completion activity, 1983–2002. (B) Yearly oil and gas production, 1983–2002; MMcf = million cubic feet.

are classified into two general lithofacies: brachiopod-coralline biostromal limestones and dolomite (Al-Shaieb and others, 2003). In Pottawatomie and Seminole Counties, reservoirs in the Chimneyhill Subgroup and the Frisco Formation are productive. The more mature part of the play in Lincoln and Logan Counties was examined.

Lincoln County

The decline in oil and gas production within Lincoln County was drastically reversed by the Hunton development in the Carney area, which began in 1997. Between 1998 and 2001, 190 oil wells and 50 gas wells were completed, for an average of 47 oil wells and 12 gas wells per year. The average number of completions for the previous 5 years (1993 to 1997) was only 16 oil wells and 6 gas wells per year. Drilling and completion activity for Lincoln County are shown in Figure 11.

Graphs of production data (Fig. 11) reflect this increased activity. In 1997, Lincoln County produced 1.37 million barrels of liquids and 8.9 Bcf gas. In 1999, the annual production of liquids increased to 2.3 million barrels. That same year, gas production exceeded 14.1 Bcf. Oil production peaked in the year 2000 at over 3.4 million barrels, a more than 240% increase over 1997. Gas production peaked in 2001 at 25.8 Bcf, which represents an almost threefold increase over a 3-year period.

Logan County

Logan County hosts the Hunton reservoir that contains fluids with higher gas-oil ratios. The Hunton play in Logan County began in 1999. The number of oil-well completions increased from 15 in 1999 to 26 in the year 2000. Concurrently, the number of gas wells doubled from 9 to 18. In 2001, the number of oil completions peaked at 35, whereas gas completions peaked at 26. Completion activity for Logan County is shown in Figure 12.

The graph of production for Logan County reflects the increased drilling activity. Oil production jumped from 1.58 million barrels in 1997 to 3.12 million barrels in 2001. Gas production increased from approximately

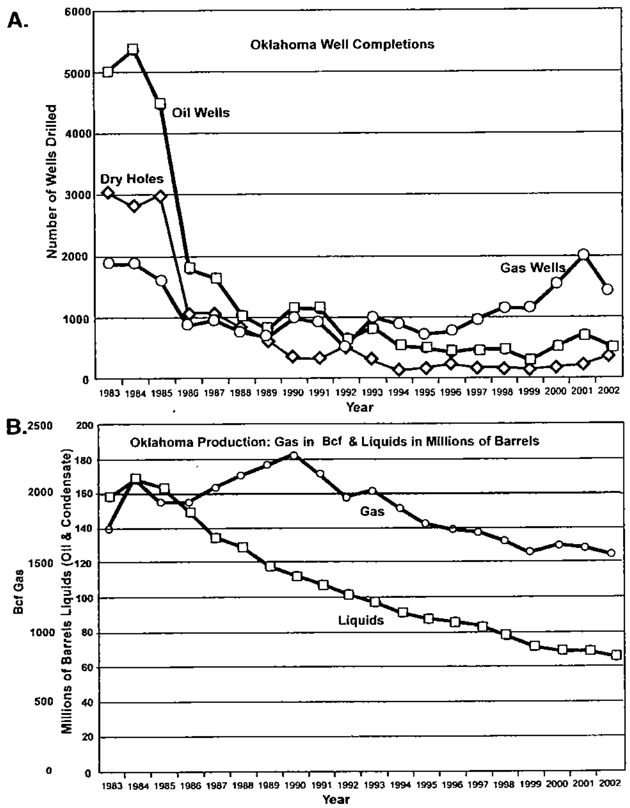


Figure 13. Graphs of oil- and gas-well–completion activity and yearly oil and gas production for Oklahoma. Although the number of oil and gas wells completed generally increased between 1996 and 2001, this increasing activity did not produce adequate volumes to impact the decline evident on the production curves. Note that since 1993, the number of gas wells completed exceeds the number of oil wells, thus transforming Oklahoma from an oil-producing state to a gas-producing one, based on well type. (A) Yearly well-completion activity, 1983–2002. (B) Yearly oil and gas production, 1983–2002; Bcf = billion cubic feet.

15.4 Bcf in 1997 to 26.9 Bcf in 2001. These changes are illustrated on Figure 12.

SUMMARY

Graphs of annual oil and gas production and completions for Oklahoma (Fig. 13) indicate that statewide production is declining in spite of recent increases in drilling activity. Furthermore, the plot of drilling activity data (Fig. 13) illustrates how the maturation of conventional oil-producing areas, in combination with deep gas exploration and unconventional energy development transformed Oklahoma from an oil-dominated province into a gas-dominated one.

Unconventional energy development has reversed the production decline in several areas and reduced it in others. The more striking of these are CBM development in the Cherokee Basin of northeastern Oklahoma and the Hunton play in north-central Oklahoma. CBM is also contributing significant volumes of gas production in the Arkoma Basin, but this contribution is often masked on decline curves by high-volume conventional base production. Other unconventional plays, including tight-gas-sandstone development in the Strong City District, Anadarko Basin, have not reversed the decline in production.

REFERENCES CITED

Al-Shaieb, Z.; Rechlin, K.; and Chernicky, D., 2003, The central Oklahoma Carney district: a unique Hunton oil and gas play [abstract]: American Association of Petroleum Geologists 2003 Annual Convention Official Program, v. 12, p. A4.

Godwin, C. J., 2004, Electrofacies, depositional environments, and petroleum geology of the Hartshorne Formation, part of Hughes and Pittsburg Counties, Oklahoma: Oklahoma State University, Stillwater, unpublished M.S. thesis, 209 p.

Huhnke, M., 2004, Depositional environments and distribution of the Prue Sandstone, northern Nowata County, Oklahoma: Oklahoma State University, Stillwater, unpublished M.S. thesis, 62 p.

IHS Energy, 2003, IHS ENERGY/P I DWIGHTS PLUS on CD: IHS Energy, Englewood, Colorado.

Oklahoma Corporation Commission, 2003, Drilling activity in Oklahoma: Oil and Gas Conservation Division, Statistical and Surety Division, electronic file www.occ.state.ok.us

Puckette, J.; and Al-Shaieb, Z., 2002, The Red Fork Sandstone: Overview of marine and deep-marine reservoirs, *in* Boyd, D. T. (ed.), Finding and producing Cherokee reservoirs in the southern Midcontinent, 2002 symposium: Oklahoma Geological Survey Circular 108, p. 119–133.

Interaction of Methane, Organic Solids, and Water in Paleozoic Basins: Implication for Accumulation of Coalbed Methane, Shale Gas, and Tight Gas

Alton A. Brown
Consultant
Richardson, Texas

INTRODUCTION

Unconventional methane accumulations (coalbed methane, gas shale, tight-gas sand) and conventional gas accumulations represent a small fraction of the methane stored in sedimentary basins. Unlike oil, methane can accumulate by dissolving in water and sorbing onto organic matter in sedimentary basins. The amount of stored methane can be considerably greater than the combined recognized conventional and unconventional reserves, although most of this methane is so dispersed that it can never be economically recovered. Although uneconomic itself, the stored, dispersed methane controls the distribution of potentially economic, unconventional methane accumulations. This paper briefly outlines how methane storage reacts to basin burial and exhumation and how methane-storage processes control distribution of economically recoverable unconventional methane.

METHANE-STORAGE MECHANISMS

Methane dissolves in water, sorbs on organic matter, and forms a gas phase in pore spaces of rock. Methane dissolution is rapid, so water near thermally mature source rocks and along gas-migration pathways becomes saturated with methane. For pressure and temperature conditions expected in Midcontinent basins, methane solubility increases with increasing depth.

Methane sorption on mineral matter is negligible; however, methane sorption on organic matter can be significant. Methane is sorbed from methane dissolved in pore water, so sorbed methane readily equilibrates with dissolved methane. Methane sorption increases with increasing methane partial pressure, but decreases with increasing temperature for any fixed rank of organic matter. Sorption capacity generally increases with increasing organic matter rank. Thus, increasing sorption due to greater pressure and greater rank during burial is offset by lower sorption capacity related to increasing temperature.

Methane storage as gas in porosity increases with pressure and decreases with temperature, as described by the gas law. Gas-phase storage has a much greater capacity than either sorption or dissolved-methane storage. In most basins, the volume of gas-saturated porosity is small compared with the volume of organic matter and water, and, thus, the sorbed- and dissolved-methane resource is much larger than gaseous-methane resource.

METHANE-STORAGE TRENDS DURING BURIAL

Methane behavior during basin burial is quite different from that during exhumation. Methane is generated from organic matter during burial. Even the small amounts of Types II and III kerogen dispersed in typical sedimentary shales and sandstones (TOC <0.5%) generate more methane than can be stored by sorption and dissolution soon after the sediment enters the oil-generation window. The dissolution and sorption-storage reservoirs are therefore saturated in deep, thermally mature parts of basins. Excess methane migrates to thermally immature parts of the basin as gas or as a dissolved component in oil. In either case, methane dissolves into pore water from the petroleum along the migration route, and methane dissolved in water sorbs onto immature organic matter. Petroleum generation and migration probably saturates water and organic matter wherever petroleum migrates. If the water and kerogen are saturated with methane, then deep, thermally mature basins such as the Anadarko and Arkoma Basins contain exceptionally large dispersed methane resources, 1,600 trillion cubic feet (Tcf) and 900 Tcf in these basins, respectively. The vast majority of this resource is hopelessly dispersed as dissolved methane or methane sorbed on dispersed kerogen, so most of this resource can never be produced economically. Porosity decreases during burial, and, thus, increasing methane solubility in pore-water is offset by decreasing porosity with increasing depth of burial. The rock-porosity–to–kerogen ratio determines whether dissolved- or sorbed–methane storage is greater.

METHANE-STORAGE TRENDS DURING EXHUMATION

Basin uplift and erosion (exhumation) causes methane generation to stop. Temperature and pressure

Brown, A. A., 2005, Interaction of methane, organic solids, and water in Paleozoic basins: implication for accumulation of coalbed methane, shale gas, and tight gas, *in* Cardott, B. J. (ed.), Unconventional energy resources in the southern Midcontinent, 2004 symposium: Oklahoma Geological Survey Circular 110, p. 29–30.

decrease, but porosity and rock thermal maturity remain approximately constant. As temperature decreases, kerogen-sorption capacity increases and methane solubility decreases. Methane therefore transfers from dissolved storage to sorbed storage during exhumation. This transfer keeps thermally mature kerogen and coal fully methane-saturated during uplift. If the porosity-to-kerogen ratio is high, then excess methane that is exsolved from the water forms a gas phase. The exsolved gas can coalesce, migrate, and charge late accumulations where rock properties are favorable and where uplift is sufficient.

IMPLICATIONS FOR UNCONVENTIONAL METHANE ACCUMULATIONS

With these concepts in mind, the controls on occurrence of unconventional methane accumulations in southern Midcontinent Paleozoic basins can now be evaluated. There are five generally recognized unconventional methane occurrences: coalbed methane (CBM), shale methane, tight gas sand, geothermal-geopressured methane, and methane hydrate. Methane hydrate is not stable under any conceivable setting in Midcontinent basins, so it will not be discussed further. Geothermal-geopressured methane corresponds to methane-dissolution storage discussed above. It has not been produced economically anywhere, but high thermal gradient, high porosity and permeability, and geopressure are likely to favor potential economic development. Because none of these features are characteristic of southern Midcontinent Paleozoic basins, Midcontinent geothermal-geopressured methane potential is small.

Coalbed methane requires a relatively high sorption capacity (moderate to high thermal maturity), methane saturation near sorption capacity, and relatively low confining pressure, so that a modest pressure drop releases large amounts of methane. Economic CBM is therefore only likely in exhumed basins, because these are the settings where relatively high-rank coal is sufficiently shallowly buried for low pore pressure. As discussed previously, methane stored in water is transferred to sorption storage during uplift, so that the coals exhumed to the near surface environment are saturated with methane (assuming sufficient methane was generated to saturate the coal and pore-water during burial). Where coal has a thermal maturity corresponding to vitrinite reflectance less than about 0.8%, insufficient methane has been generated to saturate the coal. These immature coals are more likely to be insufficiently charged. Migration of methane or microbial methane generation must be active to saturate the coal. Near-surface water movement also affects methane saturation. Where meteoric water flows downdip through thermally mature coal, methane can be stripped from the coal, because the undersaturated water will equilibrate with sorbed methane on the coal. Where meteoric water flows downdip through immature coal, meteoric water may initiate microbial methane generation, so basinward water flow may aid charge to immature coals. Flow of deep water updip through immature coals will deliver thermogenic methane to the coal. Thus, resurgent flow along an immature coal seam may charge it with thermogenic methane. In all cases, water flow through coals should be carefully evaluated for their effects on methane saturation.

Gas shale can store methane as a sorbed phase and as a gas phase. Sorbed methane in shale is controlled by the same mechanisms as CBM. Thus, this type of gas shale can only be produced from shallow settings, with thermal maturity and water movement controlling the methane charge as discussed for CBM. Complications from diagenesis and fracturing are greater in shallow gas shales than in CBM. In contrast, most gas produced from deep gas shales (such as the Barnett Formation) is produced from porosity storage of a gas phase. This type of gas shale is intermediate to tight gas sand. The porosity–TOC ratio, kerogen type, and thermal maturity determine if porosity is gas-saturated. For oil-prone kerogens, a porosity–TOC ratio of 1 or less is required, and, where the ratio is near 1, the kerogen must be in the late oil window or the gas window to generate sufficient methane to saturate the pore volume.

Tight gas sands are difficult to charge with methane because the permeability is so low and threshold capillary pressure is so high that capillary pressure equivalent to 500–1,000 ft of gas column is necessary to have water-free production. These high capillary pressures are unusual, especially where traps are subtle features. High gas saturation results from either charge before cementation, expansion of gas during exhumation, or exsolution of gas during exhumation. Exsolution produces small fractional gas saturation, so exsolution effects during uplift are unlikely to significantly increase gas saturation. Gas expands sufficiently during exhumation to change zones with high water saturation to zones capable of producing water-free gas. Expansion is an especially favorable mechanism for settings with high gas saturation in high-thermal-maturity reservoirs at shallow burial depth. However, gas must be present before exhumation to expand in the tight gas reservoir. Pre-cementation gas charge (or oil-charge followed by gasification) is necessary to saturate tight-gas sands with insufficient structural closure for the observed saturation.

Characteristics of Coalbed Methane and Shale Gas: Similarities, Differences, and Overlooked Resources

Andrew R. Scott
Altuda Energy Corporation
San Antonio, Texas

ABSTRACT.—Unconventional energy resources such as coalbed methane and shale gas have emerged as important sources of natural gas in the United States. One of the earliest known shale-gas plays in the 1920s was the Mulky shale-gas play in the Cherokee Basin that was actually a combination of production from carbonaceous shale and the Mulky coal seam. Therefore, the earliest known coalbed-methane production may have been from the Midcontinent region. Since that time, operators have re-discovered that carbonaceous shales associated with coal seams commonly represent an incremental source of gas reserves beyond coalbed methane. However, associated shale-gas resources are still often overlooked when evaluating coalbed-methane prospects, thereby underestimating the in-place gas resources and reserves of a prospect area.

Coalbed methane and shale gas have identical gas-storage characteristics, because the gas is stored (sorbed) on the organic fraction of the coal or shale. Sorption of gas by clay minerals within shales contributes to the overall gas content of the shale, but most of the gas is sorbed to the organic fraction. Therefore, the amount of gas sorbed on shales and coal seams is directly proportional to the organic-matter content, and the production of shale gases is enhanced from decreasing reservoir pressure similar to coalbed methane. Because the organic content is generally low in shales, a greater thickness of shale is required for higher shale-gas production. The major contrasts between shale gas and coalbed methane is the hydrogeology and the permeability.

Scott, A. R., 2005, Characteristics of coalbed methane and shale gas: similarities, differences, and overlooked resources, *in* Cardott, B. J. (ed.), Unconventional energy resources in the southern Midcontinent, 2004 symposium: Oklahoma Geological Survey Circular 110, p. 31.

The Barnett Shale: An Unconventional Gas Play in the Fort Worth Basin—Now the Largest Gas Field in the State of Texas

Jeffrey D. Hall
Devon Energy Corporation
Oklahoma City, Oklahoma

ABSTRACT.—The Newark East Field is located within the Fort Worth Basin of North Texas and has developed into the largest gas field within the State of Texas. The productive formation is the Mississippian Barnett Shale, an organic rich, very dense black shale with 3–5% porosity, <0.001 md permeability, and >140 billion cubic feet (Bcf) per square mile of gas-in-place (Fig. 1). Production in the Newark East Field is now approaching 1 trillion cubic feet of natural gas, >220 Bcf in 2002 alone, and is currently producing >900 million cubic feet per day from more than 3,000 wells. More than 60 companies participate in the play with 55 rigs actively targeting the Barnett.

The core area of the Newark East Field is now approaching full development on 40-acre spacing. The current field limits are being tested by wells targeting the Barnett Shale to the east and northeast into the deepest portion of the basin adjacent to the Muenster Arch, to the north toward the oil window, and to the south into the Fort Worth metropolitan area. The greatest challenge facing the Barnett play expansion lies to the west and southwest into western Wise, Parker, and Johnson Counties, where the underlying Ordovician tight limestone frac barriers, which are viewed as key to successful wells, are absent. Several wildcat wells have tested the Barnett to the south and west utilizing both vertical and horizontal technology with varied results.

Clearly, the conventional technology developed within the core area will not be applicable to all of the expansion and exploration areas. A greater understanding of the Barnett Shale as a reservoir, as well as increased study of the frac barriers below, above, and within the Barnett Shale, are now necessary. Armed with this knowledge, the drilling and completion technology can be developed to allow for the successful expansion of the play.

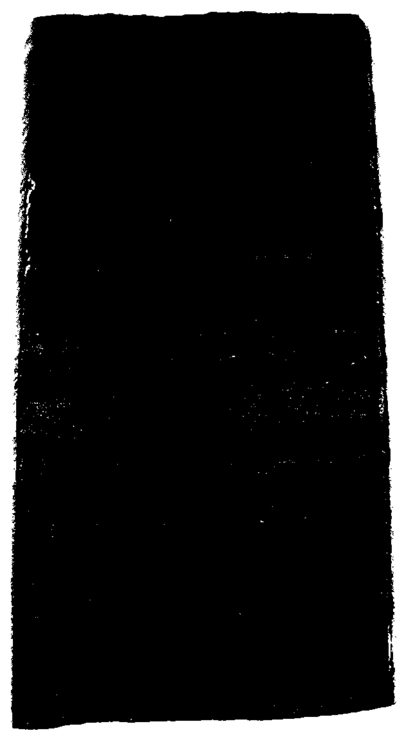


Figure 1. Photograph of lower Barnett Shale whole core in Newark East Field, Wise County, Texas.

Hall, J. D., 2005, The Barnett Shale: an unconventional gas play in the Fort Worth Basin—now the largest gas field in the State of Texas, *in* Cardott, B. J. (ed.), Unconventional energy resources in the southern Midcontinent, 2004 symposium: Oklahoma Geological Survey Circular 110, p. 33.

The Barnett Shale Play, Fort Worth Basin

Kent A. Bowker
Independent
The Woodlands, Texas

ABSTRACT.—The Newark East field (Barnett Shale) recently became the largest gas field in Texas in terms of monthly production. Production has grown from 80 million cubic feet of gas per day (MMcfd) in January 2000 to more than 700 MMcfd at present because of accelerated new-well drilling and old-well reworks/refracs. More than 2.5 trillion cubic feet of booked proven gas reserves presently exist in the field.

The Newark East field is located in the northern portion of the Fort Worth Basin, just north of the City of Fort Worth. The Mississippian Barnett Shale rests on an extensive angular unconformity. The Barnett must be stimulated to achieve economic flow rates. Currently, wells are hydraulically fractured, but good frac barriers must be present directly above and below the Barnett for this stimulation technique to be successful. Hence, the stratigraphy above and below the Barnett is important to economic production from vertical wells. Recent horizontal drilling has shown great promise to expand the play outside the current economic limits of the play.

The thermal history of the basin is an important reason for the success of the Barnett. The thermal history of the Fort Worth Basin is directly related to the emplacement of the Ouachita system. Sections of the Barnett bordering the Ouachita front (regardless of depth) have the highest thermal maturity and, hence, the lowest BTU content of produced gas. In the late 1990s, work by Mitchell Energy had demonstrated the viability of water fracs in the Barnett play. This development has contributed to a huge acceleration in Barnett leasing and drilling activity during the past 3 years. Also in the late 1990s, Mitchell Energy determined that the previous gas-in-place values for the Barnett were low by over a factor of three. There is approximately 150 billion cubic feet of gas per square mile of in-place gas in Newark East field. The realization that the primary completion was only recovering 7% of the gas in place per well spurred the current (and very successful) rework/refrac program underway in the field.

The history of the evolving geologic and engineering concepts that guided development of the Barnett is a tribute to rare perseverance in the oil patch. And the success of the Barnett play may provide a model for prospecting for other large shale reservoirs.

Bowker, K. A., 2005, The Barnett Shale play, Fort Worth Basin, *in* Cardott, B. J. (ed.), Unconventional energy resources in the southern Midcontinent, 2004 symposium: Oklahoma Geological Survey Circular 110, p. 35.

Assessment of the Gas Potential and Yields from Shales: The Barnett Shale Model

Daniel M. Jarvie
Humble Geochemical Services
Humble, Texas

Ronald J. Hill and Richard M. Pollastro
U.S. Geological Survey
Denver, Colorado

ABSTRACT.—The Newark East gas field in the Ft. Worth Basin, Texas, is now the largest producing gas field in the State of Texas. Production of gas is primarily from the Mississippian Barnett Shale. Although gas and some oil are produced from horizons younger and older than the Barnett Shale, the bulk of gas production comes from the low-porosity (ca. 6%) and low-permeability (ca. 0.02 mD) shale itself. Thus, the Barnett Shale functions as the source, reservoir, and seal for the Total Petroleum System.

Several components are key to geochemical evaluation of the Barnett Shale play, including assessment of organic richness, original hydrocarbon potential, thermal maturity, gas content, gas yields, secondary cracking of oil to gas, and burial-history models.

Overall, assessing gas prospects in the Barnett Shale from a geochemical perspective requires risking geochemical data, primarily those data related to, or a function of, the maximum thermal heating of the organic matter. Risking parameters such as TOC, vitrinite reflectance, T_{max}, kerogen transformation ratios, and gas dryness can be used to assess prospects and lease areas for potential commercial gas yields from the Barnett Shale.

The Barnett Shale was originally a Type II oil-prone kerogen based on hydrogen indices. In the main gas fairway the kerogen is highly mature and gas is derived both from kerogen cracking and oil-to-gas cracking.

Burial history modeling suggests that most hydrocarbons were generated about 250 million years before the present (Ma), although some hydrocarbons could have been generated as recently as 25 Ma. Hydrocarbon generation is not occurring today, and the main phase of hydrocarbon generation most probably occurred 250 Ma.

The Barnett Shale has very high gas yields ranging from 170 to 250 standard cubic feet of gas per ton of rock (scf/ton) based on corrected methane adsorption data from the T. P. Sims #2 well. This gas is present as 55% free gas and 45% sorbed gas, on average.

INTRODUCTION

The Ft. Worth Basin is a Paleozoic basin formed as a result of the advancing Ouachita Thrust belt. The basin margins are delimited by the Red River and Muenster arches in the north, the Bend Arch in the west, the Llano Uplift in the south, and the Ouachita structural front in the east (Fig. 1).

Evidence of the Mississippian Barnett Shale source and gas potential is provided by correlation of oil and gas to Barnett Shale source rocks. Its geochemical characteristics are further assessed by determination of the quantity of organic matter (organic richness or total organic carbon—TOC), its original hydrocarbon generation potential, its degree of conversion or transformation from kerogen to oil and gas including rates of secondary cracking of oil to gas, gas composition, carbon isotopes, and gas calorific value, gas yields per unit of shale, and burial and thermal history modeling.

The Barnett Shale Paleozoic Total Petroleum System is used to describe gas and oil generated by the Barnett Shale that is found in Paleozoic reservoirs in the Ft. Worth Basin (Pollastro, 2003; Pollastro and others, 2003). This terminology is adapted from the U.S. Geo-

Jarvie, D. M.; Hill, R. J.; and Pollastro, R. M., 2005, Assessment of the gas potential and yields from shales: the Barnett Shale model, *in* Cardott, B. J. (ed.), Unconventional energy resources in the southern Midcontinent, 2004 symposium: Oklahoma Geological Survey Circular 110, p. 37–50.

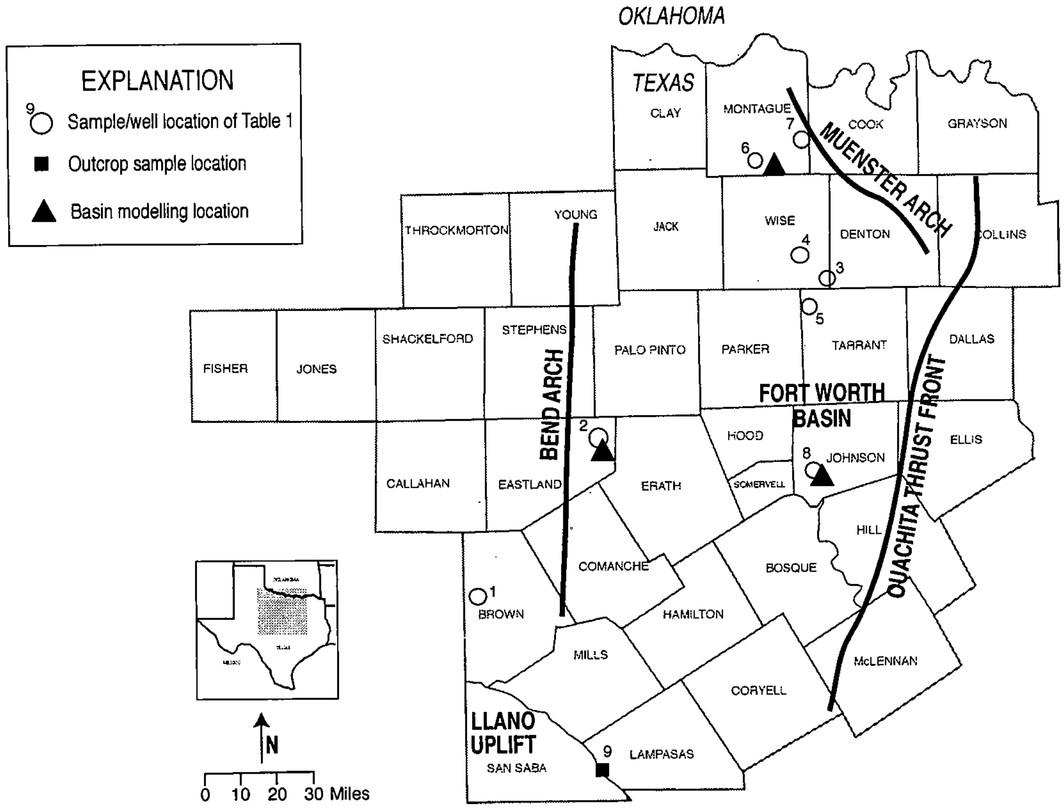


Figure 1. Generalized structural and sample-location map for wells and outcrop samples in Ft. Worth Basin.

logical Survey description of a petroleum system that includes an effective source rock, known accumulations, and an area of undiscovered hydrocarbon potential (Magoon and Schmoker, 2000). The Mississippian Barnett Shale serves as source, reservoir, and seal to gas and petroleum in the Ft. Worth Basin, Texas. Since 2002, the Newark East Field has become the largest gas field in the State of Texas.

Gas production from tight shales requires cracking of oil that has been generated from indigenous organic matter, otherwise the low porosity and permeability of the shale will be occluded. When thermal maturity levels exceed about 1.00% to 1.20% vitrinite reflectance, gas content increases rapidly due to secondary cracking of oil to gas. When cracking occurs, GOR (gas-to-oil ratios) and gas flow rates increase dramatically resulting in vertically drilled wells with high flow rates (500–2,000 thousand cubic feet of gas per day, Mcfd) and much higher rates in horizontally drilled wells.

THE SOURCE OF OIL AND GAS IN THE FT. WORTH BASIN

A detailed study of Ft. Worth Basin oils and gases is currently underway as a joint effort by the U.S. Geological Survey and Humble Geochemical Services. Oil and gas data have been reported, however, and the data show that the Barnett Shale is the source of the oil and gas in the basin (Jarvie and others, 2001; Jarvie and others, 2003; Hill and others, 2004). For example, oil fingerprinting results show that the oils are very similar in isoprenoid biomarker ratios (Fig. 2). More detailed analyses of the oils show that there may be organofacies differences within the Barnett Shale. The majority of oils have a low-sulfur marine-shale signature, whereas others have a terrestrial component and perhaps marl-lithofacies component that slightly alter the molecular composition of the oil. Barnett Shale sourced oils are found in horizons older (Ordovician Ellenburger) and younger (Pennsylvanian Strawn, Bend Conglomerate, etc.) than the Barnett Shale.

Analysis of gas samples from the Pennsylvanian Boonsville conglomerate and within the Barnett Shale appear to be sourced by the Barnett Shale (Jarvie and others, 2003). Gas in the Boonsville conglomerate (the horizon of original production prior to shale development) is wetter and has lower thermal maturity than gas produced from the Barnett Shale (Jarvie and others, 2003). It is likely that the Boonsville gases are oil-associated gases (i.e., gas co-generated from kerogen with oil within the oil window), whereas the producible gas contained within the Barnett Shale is derived from cracking of oil at higher thermal maturities. Thus, it is known that the Barnett Shale has expelled some hydrocarbons both as oil and gas.

Analysis of well samples, including cuttings and sidewall core, from wells across the Ft. Worth Basin show that the Barnett Shale is the primary source rock. While other horizons show limited source potential, correlation of oils to both oil produced from the Barnett Shale and rock extracts of the Barnett Shale confirm it as the source of most of the oil and gas produced in the basin (Jarvie and others, 2001; Jarvie and others, 2003).

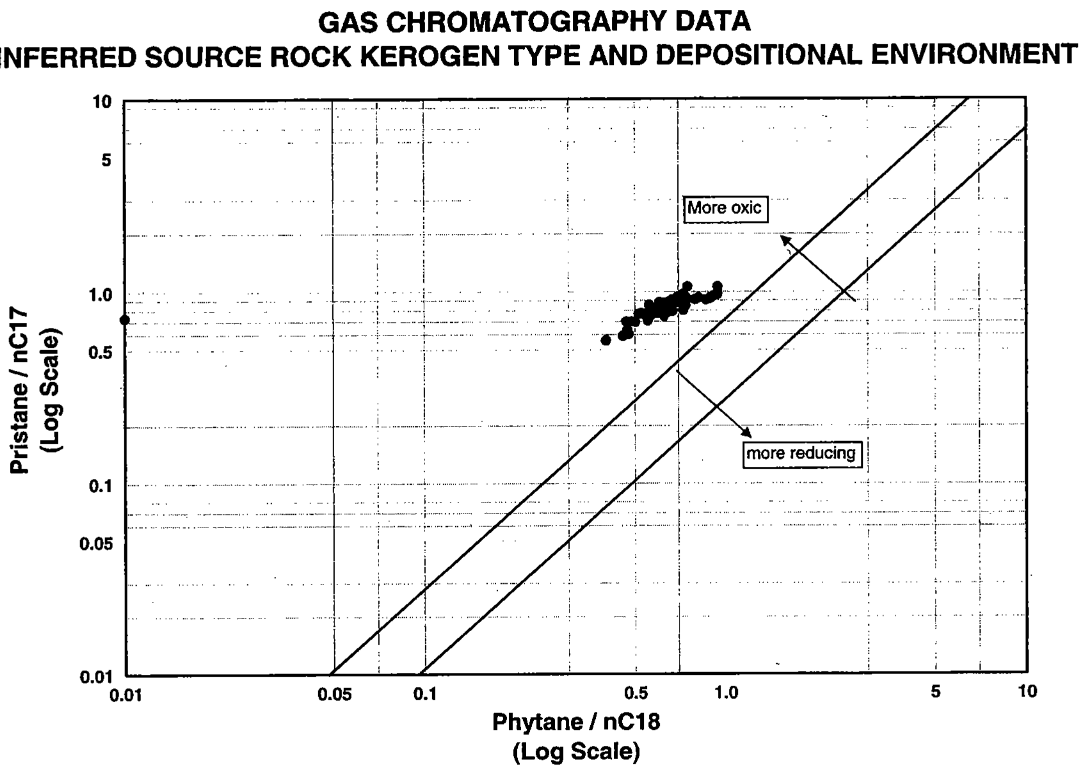


Figure 2. Classical log-log plot of isoprenoid biomarkers normalized to adjacent normal paraffins showing a high degree of similarity among 70 oils from around the Ft. Worth Basin.

Oils produced from low maturity Barnett Shale in Brown County correlate with other oils in the western portion of the basin such as Shackelford, Callahan, and Throckmorton Counties based on gas chromatographic analysis, biomarkers, and carbon isotopes (Jarvie and others, 2003; Hill and others, 2004). These same oils correlate with condensates in the central producing horizons of the Newark East Field based on light hydrocarbons, biomarkers, and carbon isotopes (Jarvie and others, 2001; Hill and others, 2004).

BARNETT SHALE SOURCE-ROCK POTENTIAL AND THERMAL TRANSFORMATION

To evaluate the geochemical characteristics of the Barnett Shale, numerous well and outcrop samples were analyzed. The wells are located in various points around the basin representing immature to highly converted Barnett Shale organic matter (see Fig. 1, well designations). The Lampasas outcrop sample and the Mitcham #1 well in Brown County in the south–southwest portion of the basin represent low maturity Barnett Shale. In Montague County to the north, the Truitt #1 and Grant #1 wells are representative of Barnett Shale in the oil window. In the heart of the gas productive area, the Sims #2, Young #1, Oliver #1, and Gage #1 wells are typical of wells in the wet to dry gas windows (Fig. 1; Table 1).

Average total organic carbon (TOC), hydrogen indices (HI), calculated and measured vitrinite-reflectance values (%VR_o), and calculated transformation ratios (TR in %) are shown in Table 1, and a modified Espitale kerogen type and maturity plot (Espitale and others, 1984) is shown in Figure 3. It is inferred from the data trend in Figure 3 that the Barnett Shale was originally a Type II oil-prone marine kerogen and was not originally either a Type III gas-prone kerogen or a Type I kerogen as has been cited from time-to-time. With increased thermal maturation, the Barnett Shale is essentially converted from a Type II into a Type III source rock. Carbon and hydrogen loss are due to hydrocarbon generation, thereby reducing the original source potential of the rock. This maturation trend is shown in Figure 3, where the decrease in HI values follows a trend of increasing thermal maturity. The maturity trend line changes from the lowest maturity outcrop sample to well samples of the very high, gas window maturity Gage, Sims, and Oliver Barnett Shale HI values.

Organic richness of the Barnett Shale is excellent having high commercial source potential (Jarvie, 2000). In addition, high storage capacity of the Barnett Shale for gas is related to its organic richness. The average TOC value determined on low maturity (Rock-Eval T_{max} <435°C) Barnett Shale formation cuttings is 3.26%, with an average generative potential of 7.86 mg HC/g rock or approximately 172 barrels of oil per acre-foot (BO/AF) or 172 Mcf/AF (Jarvie and others, 2001; Pollastro, 2003). However, these values are from cuttings samples and are likely diluted based on mixing

TABLE 1.—TOC, Rock-Eval, and Measured Vitrinite-Reflectance Values for Various Barnett Shale Samples from Cuttings, Core, and Outcrop in the Ft. Worth Basin, Texas

Map no.	Well name	TOC	HI	Potential Yields (BO/AF or MCF/AF)	T_{max}	Cal. %VR_o	Meas. %VR_o	Cal. TR
1	Mitcham #1	4.67	396	405	434	0.65	nd	0%
2	Heirs #1	3.40	68	51	454	1.01	0.9	83%
3	T. P. Sims #2	4.45	25	24	487	1.61	1.66	94%
4	W. C. Young #1	4.93	56	60	468	1.26	nd	86%
5	Oliver #1	4.30	13	12	544	2.63	nd	97%
6	Truitt A #1	4.13	261	236	445	0.85	nd	34%
7	Grant #1	4.70	299	309	446	0.86	nd	35%
8	Gage #1	2.66	39	23	485	1.57	1.37	90%
9	Lampasas Outcrop Sample 1	13.08	463	1,326	430	0.58	nd	0%

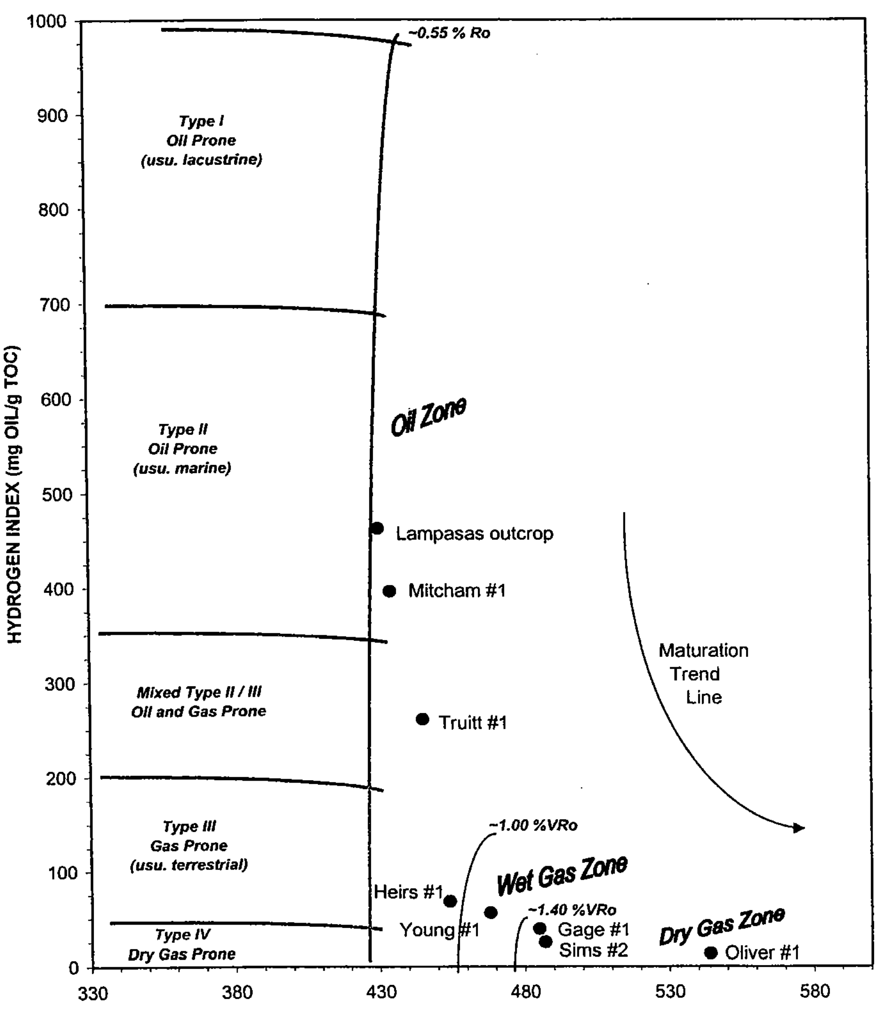


Figure 3. A modified Espitalie kerogen type and maturity (Espitalie and others, 1984) plot showing immature through post-mature Barnett Shale samples from various wells with varying burial and thermal histories across the Ft. Worth Basin. See text for abbreviations.

with massive carbonates above the Barnett Shale. On a single well, where cuttings and conventional core analysis were compared for TOC values, the TOC values on the core samples were 2.36 times higher than cuttings samples (Jarvie, unpublished data). The dilution effect on cuttings samples also indicates that other geochemical parameters measured from cuttings are lower than those measured on core, including remaining generation potential and thermal maturity. This is due primarily to cavings. Hand picking of samples does not change the values, as even lean carbonates visually appear as dark gray to black in color.

An evaluation of the hydrocarbon charge from the Barnett Shale requires a volumetric assessment of the original hydrocarbon generation potential. In the thermal limits of the gas window, the remaining generation potentials (Rock-Eval S2 values) only represent the yield of hydrocarbons that could be obtained from additional maturation or cracking of Barnett Shale. Thus, it is important to reconstruct the original hydrocarbon source potential. This is accomplished by evaluating low thermal maturity source rocks of the Barnett Shale.

Organic rich, low thermal maturity outcrops of the Barnett Shale found near Lampasas, Texas, have TOC values as high as 13% with a generation potential of 60.62 mg HC/g rock (Rock-Eval S2) or 1,327 BO/AF. Five outcrop samples from the J. R. Walker Ranch average 8.85% TOC and average 30.28 mg HC/g rock or 662 BO/AF for generation potential. In addition, organic rich, low thermal maturity well cuttings measured from the Jones Co. Mitcham #1 well have Barnett Shale that has 5.21% average TOC, with generation potentials of 19.80 mg HC/g rock (433 BO/AF). However, despite being low thermal maturity (ca. 0.60% vitrinite reflectance), this well produces a high-quality (38° API gravity, low sulfur) oil from the Barnett Shale, which is generated *in situ*. Thus, some generation and internal expulsion of hydrocarbons has occurred even at this low thermal maturity.

Cuttings from the Mitcham #1 well were artificially matured in the laboratory to evaluate the rates of decomposition for the Barnett Shale in an attempt to simulate organic matter transformation in nature (Jarvie and Lundell, 1991). While this extrapolation is orders of magnitude from the laboratory compared to the natural geological environment and time frame, the data correlate well to data for more mature Barnett Shale. These data sets were then used to determine the change in geochemical parameters with maturation (albeit laboratory induced) and then used as predictive tools. TOC is reduced by approximately 36% from its original value (Jarvie and Lundell, 1991; Montgomery and others, 2005), but the remaining potential and hydrogen index are reduced by >90%, indicative of a high degree of conversion of organic matter to hydrocarbons and a carbonaceous residue.

For comparison to the geological setting, a well in Eastland County, the Alice E. Allen Heirs #1 well, was chosen. The location of this well is downdip from the Mitcham #1 well and thus has been exposed to a much higher thermal history as evidenced by lower HI value and higher T_{max} (Fig. 4). The calculated vitrinite-reflectance value based on the formula of Jarvie and others (2001) is:

$$\text{Cal.\%VR}_o\ (\text{from } T_{max}) = 0.018 \times T_{max} - 7.16 = 1.01\%\text{VR}_o(\text{cal.}),$$

placing the Barnett Shale in this well in the latest oil–earliest condensate/wet-gas window. Guidelines from thermal maturity assessments for the Barnett Shale are suggested as follows:

Cuttings VR_o values	**Maturity**
<0.55% VR_o	Immature
0.55–1.00% VR_o	Oil window (peak oil at 0.90%VR_o)
1.00–1.40% VR_o	Condensate–wet-gas window
>1.40% VR_o	Dry-gas window

Core VR_o values	**Maturity**
< 0.55% VR_o	Immature
0.55–1.15% VR_o	Oil window (peak oil at 0.90%VR_o)
1.15–1.40% VR_o	Condensate–wet-gas window
>1.40% VR_o	Dry-gas window

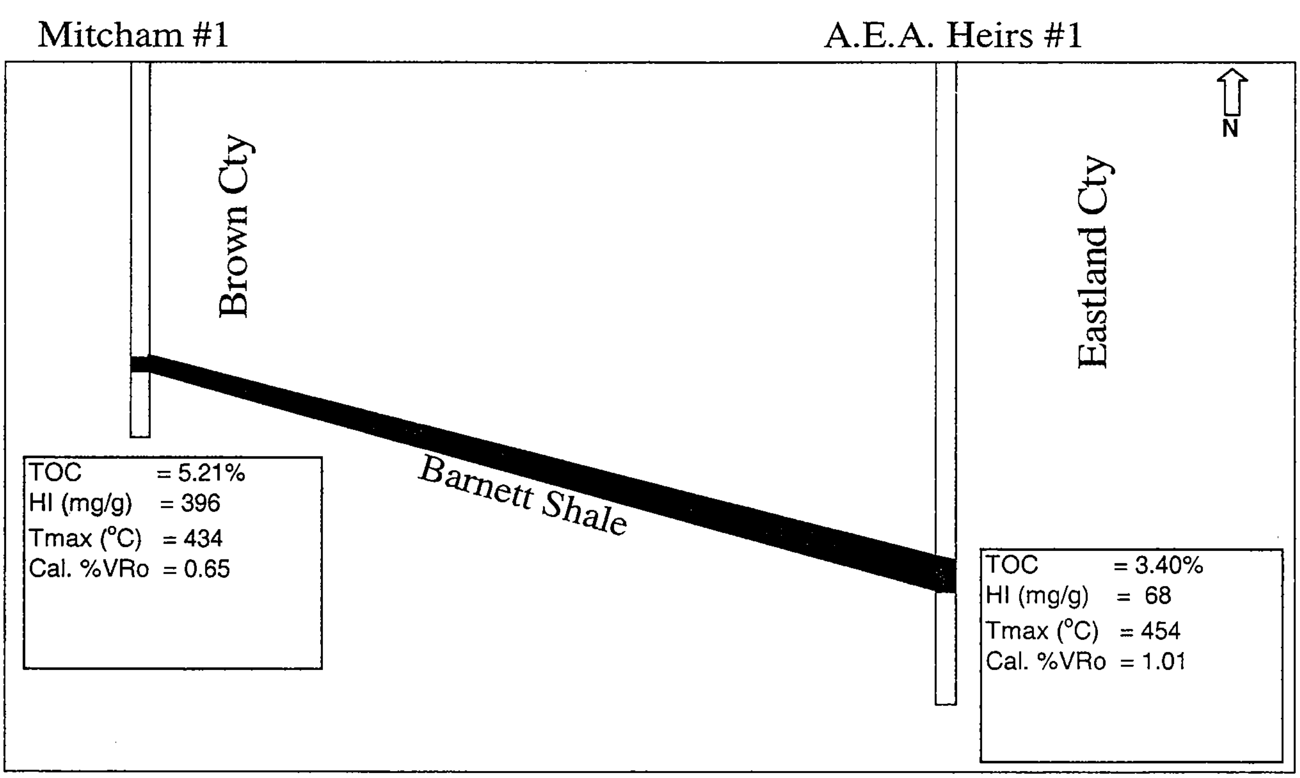


Figure 4. A schematic cross section between the Mitcham #1 well in Brown County and the downdip A. E. Allen Heirs #1 well in Eastland County with measured geochemical parameters. See text for abbreviations.

A gray area exists in the 1.00–1.20% VR_0 range, but 1.20% VR_0 is certainly in the condensate–wet-gas window and in the gas-productive sweet spot.

The Heirs #1 well has a calculated original TOC of 5.31% (i.e., present-day TOC/0.64). This is what would be expected for an equivalent facies of the Barnett Shale, which it appears to be. The change in TOC for the Heirs #1 well is a result of hydrocarbon generation, so the original generation potential can be calculated using an average value of carbon in hydrocarbons (83%), converting weight percent to mg hydrocarbons/g rock (ppt), and adding the present-day remaining potential (S2 = 2.31):

$$TOC_{change} = TOC_{original} - TOC_{present} = 1.91 \text{ wt } \%$$

$$TOC_{change} / 0.083 = 1.91 / 0.083 + 2.31 =$$
$$25.35 \text{ mg hydrocarbons/g rock (original S2)}$$

It then follows that the original HI value is

$$\text{Original HI} = \text{Original S2} / \text{Original TOC} \times 100 =$$
$$25.35 / 5.21 \times 100 = 487 \text{ mg HC/g TOC}$$

From these data the kerogen transformation ratio can be computed:

$$\text{Transformation ratio (in \%)} =$$
$$(HI_{original} - HI_{present}) / HI_{original}$$

$$TR (\%) = (487\text{-}68) / 487 \times 100 = 86\%$$

A second example from the main gas-producing area (Newark East Field), the T. P. Sims #2 well, contains high thermal maturity Barnett Shale, as would be expected in this part of the basin. Measured vitrinite reflectance is 1.66%, and the average calculated vitrinite-reflectance value from T_{max} is 1.61%. It has high residual TOC values and very low remaining generation potentials and hydrogen indices. The average residual TOC is 4.45%, and the remaining generation potential is 1.07 mg HC/g rock. Following the method above, the original TOC is calculated to be 6.95%, whereas the original hydrocarbon generation potential is 30.16 mg HC/g rock, and the original HI is 434. Thus, the transformation ratio (TR) is calculated to be 94%.

Calculated TR values using this method for all the wells are shown in Table 1. Note that some wells are not highly converted, thus calculation of original TOC values must be adjusted to the level of conversion. For example, at peak oil generation the TOC value is only reduced about 18% rather than 36%. The relationship between TR and vitrinite reflectance provides a method for chemical assessment of thermal maturity (Fig. 5). The plateau above 1.00% VR_0 is due to the delay between primary oil generation and elevated rates for secondary cracking of oil (primarily paraffins in the case of the Barnett Shale) to gas. Secondary cracking of hydrocarbons begins at about 145°C, whereas kerogen cracking to hydrocarbons ends at about that same temperature. Until the secondary cracking rate begins to increase rapidly, there is a plateau in gas-to-oil ratios (GOR) and gas yields.

Of course, quantitative changes are also accompanied by qualitative changes in the reaction products that are generated with increasing thermal maturity. The thermal oil window is defined as the thermal-

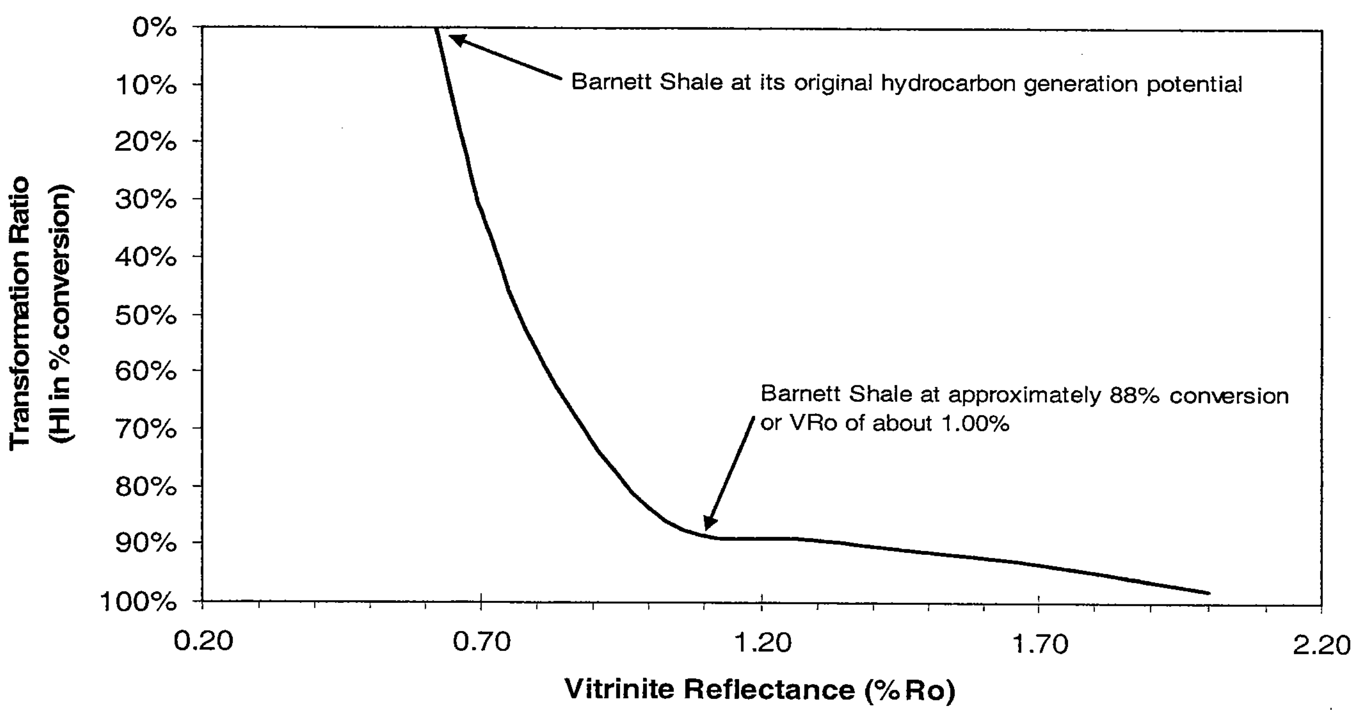


Figure 5. Relationship of Barnett Shale kerogen transformation to measured vitrinite-reflectance values. As thermal maturity increases, kerogen transformation or conversion to hydrocarbons, also increases. See text for abbreviations.

maturity zone where liquid hydrocarbons are the dominant product, although there is *always* associated gas formed in the oil window too (ca. 0.60% – 1.00/1.20% VR_o). The thermal-condensate–wet-gas window is defined as the zone where light liquids and gas are the predominant products and is near the boundary where any retained oil is cracked to lighter liquids and gas (1.0–1.4%VR_o). The thermal dry-gas window is defined as the zone where methane begins to dominate the products that are generated (>1.4%VR_o).

This is demonstrated by laboratory analysis of the products evolved from the Barnett Shale at various thermal maturities. Thermal-extraction gas-chromatographic (TEGC) fingerprinting allows the types of product contained within shale to be documented, although this does not include any lost gas (Jarvie and others, 2001).

In addition, measurement of the reaction products during compositional kinetic and yield assessments of the Barnett Shale can be extrapolated to various temperatures and maturities. Black oil and condensate-range hydrocarbons are the principal products generated in the oil window with estimated equivalent vitrinite-reflectance values of 0.60–1.00% VR_o. Above about 1.00% VR_o, the predominant product is wet gas (C_2–C_4 hydrocarbons), and gas accounts for 50% of the product distribution. Above about 1.40% VR_o, methane becomes the predominant hydrocarbon that is formed from kerogen. In addition, at temperatures greater than about 145–150°C, any retained oil will also begin to crack at about 1.0% VR_o (depending on the heating rate), and the yield of gas will increase exponentially from that point forward.

Present-day temperatures at the Barnett Shale level are certainly not at the temperatures necessary to crack organic matter of any form, whether kerogen or oil; however, maximum paleo-temperatures were much higher. Based on offsets in vitrinite-reflectance data in the Mississippian, it is estimated that approximately 5,500 ft of strata has been removed by erosion (Fig. 6), although it may be speculated that more or less erosion has also occurred based on the distribution of measured vitrinite-reflectance values. Although it is not known how much Permian section has been eroded, one can certainly identify thousands of feet of Permian sediments in the Permian Basin just to the west of the Ft. Worth Basin. Thus, due to the hypothesized deeper burial and temperature exposure, the Barnett Shale was likely at one time in the temperature regime of 150–190°C in the Newark East Field.

These temperatures also may have been attained or aided by hydrothermal events as speculated by Bowker (2002, 2003) and Pollastro and others (2003, 2004). These authors speculate that the Ouachita Thrust forced hot fluids through the Ellenburger heating the overlying Barnett Shale to higher temperatures than could be accomplished by depth of burial. The presence of saddle dolomites that have been found in the Chappel Formation in the southwestern portion of the basin and in the Hardeman Basin to the northwest as well as native cooper are cited as evidence for this hydrothermal event (Bowker, 2002, 2003).

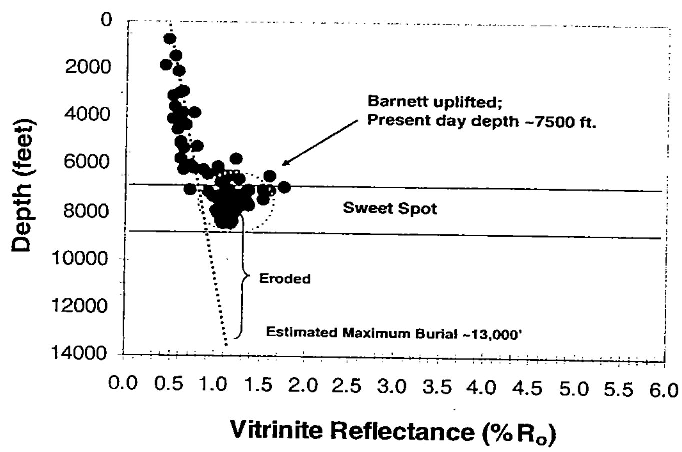


Figure 6. Vitrinite-reflectance data from Denton, Tarrant, and Wise Counties, showing a variable dog-leg gradient from the Pennsylvanian section through the Barnett Shale. A mid-point drop point suggests about 5,500 ft of erosion.

Burial and thermal-history models show that the Barnett Shale is in the oil window in the north (Truitt #1 well, Montague County) and is in the gas window based on models of the Gage #1 well in Johnson County and the Alice E. Allen Heirs well in Eastland County (Fig. 7A–C).

Burial and thermal-history models show hydrocarbon generation from the Barnett Shale occurred as early as 250 Ma (Fig. 7A–C). Unconformities are first estimated from geological data and then optimized using geochemical data, especially vitrinite reflectance. These models utilize Barnett Shale kinetic parameters (rate data for the decomposition of Barnett Shale kerogen) and show the highest level of oil or gas generation at maximum paleo-temperatures. The Barnett Shale contains a low-sulfur kerogen and generates oil and gas at slightly higher temperatures than sulfur- or sulfur/oxygen-rich kerogens such as carbonates (Fig. 8). The calculated transformation rate curves of Figure 8 show the conversion of organic matter at increasing temperature using an arbitrary constant heating rate of 3.3°C per m.y. This illustrates that the rates of organic-matter decomposition are variable and dependent on the composition as well as the structure of the organic matter. The rate of transformation for the Barnett Shale is typical of low-sulfur, marine kerogens (Claxton, personal communication).

Note that, although the grayscale shading (see Fig. 7A–C) shows the Barnett Shale to be in the oil or gas windows at present-day, this only reflects maximum burial paleo-temperature, as it is not currently generating any hydrocarbons based on present-day temperatures.

BARNETT SHALE GAS RESERVOIR YIELD

An important aspect of any gas shale or unconventional gas play is the need for gas-yield data (i.e., the amount of gas that can be released from the rock in scf/ton). Typically, this analysis is done on core samples

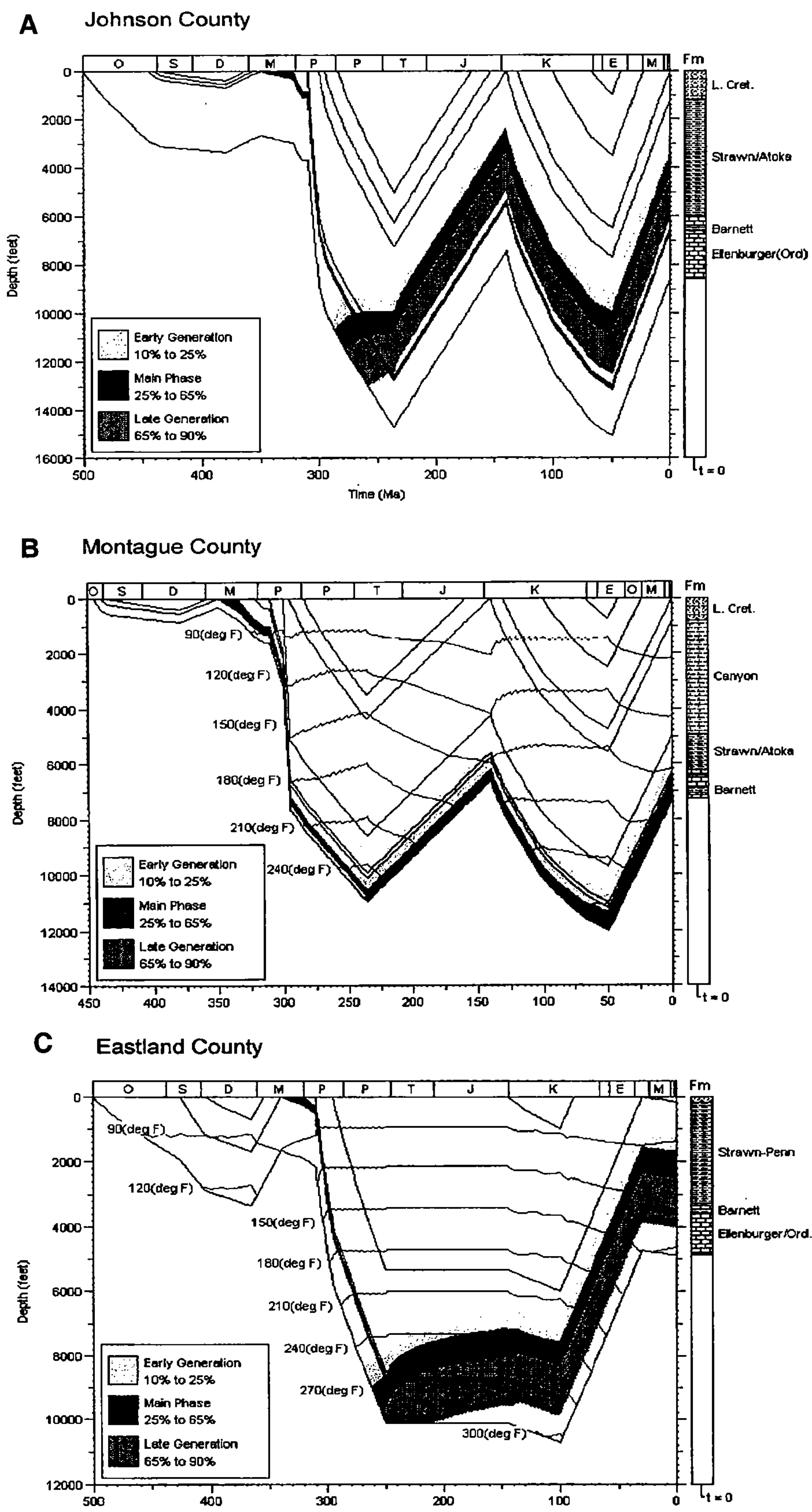


Figure 7. Burial and thermal history models of three wells in the Ft. Worth Basin. (A) The Gage #1 well in Johnson County shows gas window thermal maturity due to a very deep burial about 250 million years ago (Ma). (B) The Truitt #1 well in Montague County shows oil-window thermal maturity due to significantly less burial and maximum-temperature exposure for the Barnett Shale. (C) The Heirs #1 well shows early condensate–wet-gas window thermal maturity and less erosion in the Paleozoic section.

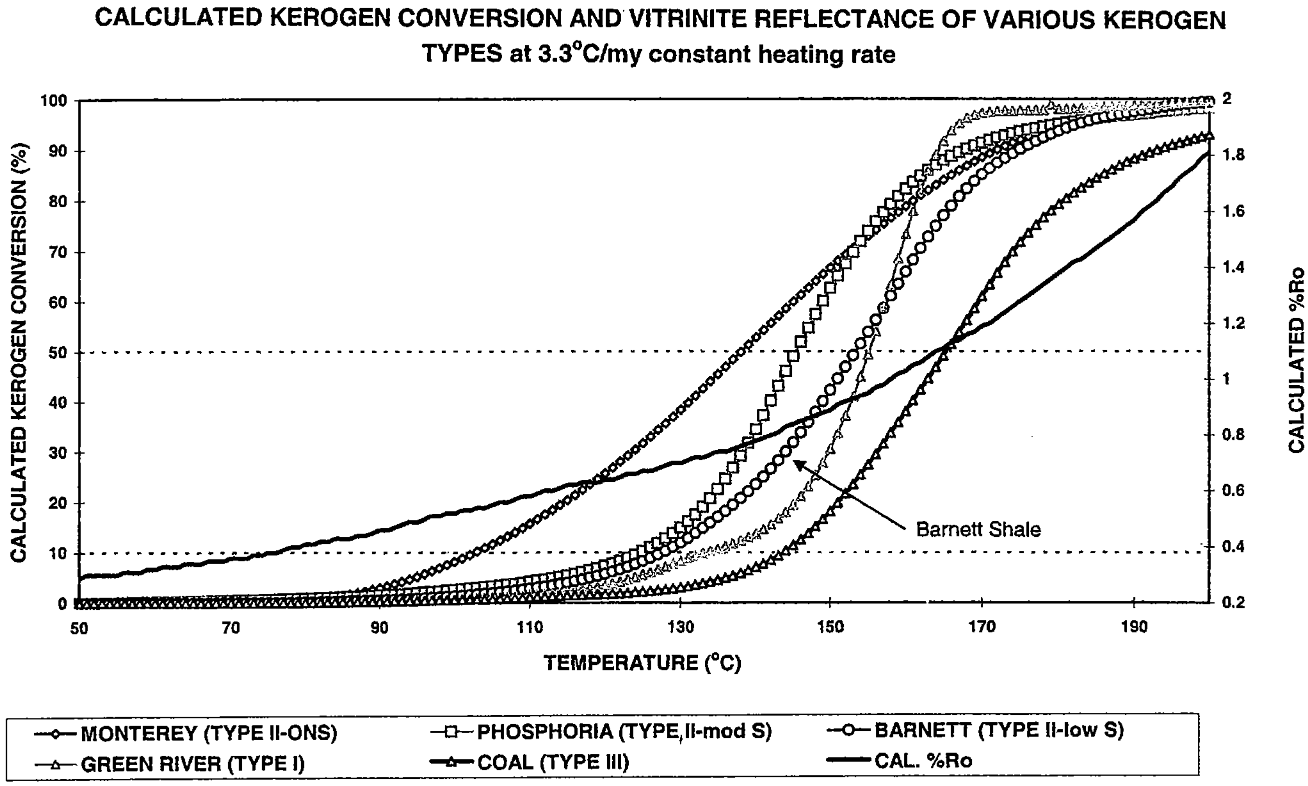


Figure 8. Rates of organic-matter conversion (transformation ratio in %) are variable and show the Barnett Shale to be more refractory than higher sulfur kerogens. See text for abbreviations.

collected at the well site in canisters, but an approach using cuttings in gas impermeable bottles (Iso-Jars) has provided comparable yields in the Barnett Shale (Fig. 9). This does not eliminate the need for core tests, but it does mean that these analyses can be provided on a much broader scale since the cost is much less (no coring, inexpensive analysis).

There is also a need to understand how gas is stored in the Barnett Shale. Sorbed gas refers to gas stored in either an adsorbed or absorbed state. In adsorption, the gas is physically or chemically attached to the inorganic or organic matrix in the rock. A physical attraction is a physico-chemical bond that is relatively weak. A chemical bond, on the other hand, is quite strong, and evidence for this type of bond does not exist in the Barnett Shale. Absorption refers to gas in solution with a solute, such as solution gas. Thus, the term sorbed is commonly used to describe the gas stored in the Barnett Shale without differentiating by which process it is held.

Experimental data acquired by monitoring the gas released from the mud gas (lost gas) versus the gas that desorbed from cuttings both before and after crushing provides an indication of gas yields. From one well the lost gas accounted for about 43% of the total gas. The gas that desorbed was equal to about 18% of the gas, whereas the gas released upon crushing of the cuttings accounted for the last 39% of the gas. This suggests that about 43% of the gas is free gas, 18% is sorbed gas, and the remaining 39% is a combination of free and sorbed gas that would only be released upon further stimulation such as fracturing an interval.

Gas-adsorption data published by the Gas Research Institute (1991) was reworked by the senior author subjectively eliminating bad data points, i.e., adsorption yields that decreased with increasing pressure. These data provide sufficient information to evaluate gas yields at reservoir pressures, which are approximately 3,800 psi in the Barnett Shale. There is inherent variability in the total and adsorbed gas yields within the Barnett Shale as shown by two sets of data (Fig. 10). From nine different sets of reworked experimental data, the total gas yields range from 170 to 250 scf/ton, whereas the adsorbed gas ranges from 60 to 125 and the free gas from 110 to 125 scf/ton (by difference). Gas storage appears to be related to the mineralogy of the interval as the TOC values are typical of high-maturity Barnett Shale samples (~4.50%) except for one sample. The T. P. Sims lithology log shows considerable variation ranging from clay-rich to silica-rich zones. Similarly, available mineralogy data published by GRI on the W. C. Young #2 well that was also studied by the Gas Research Institute (1991) shows a range of mineralogical composition ranging from 0% to 54% clay, 4% to 44% quartz, 0% to 78% calcite, and other minerals such as pyrite, apatite, dolomite, and minor amounts of other minerals (Table 2). The TOC values are very consistent in this interval, so the variability in gas contents and how it is stored appears to be more likely a function of the variable mineralogy. Other reports, however, have shown a near-perfect correlation of TOC to gas yields (Dougherty, 2004, personal communication) when sample testing was well constrained.

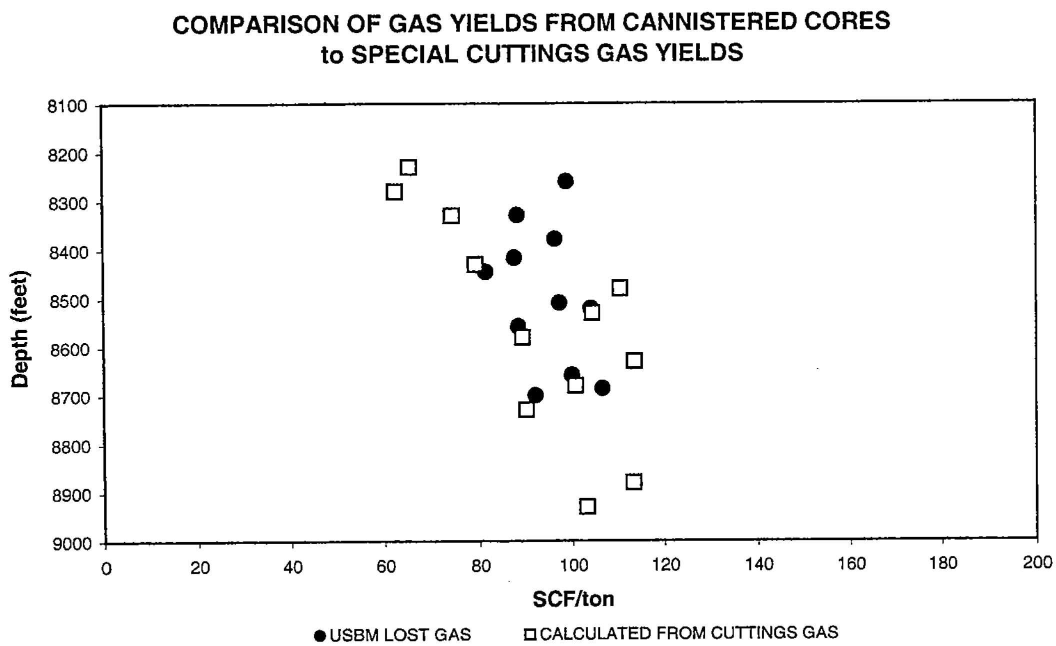


Figure 9. Correlation of U.S. Bureau of Mines (USBM) desorption gas yields to gas yields determined from bottled cuttings samples. Desorption gas yields from cuttings allow high density sampling and assessment of gas potentials.

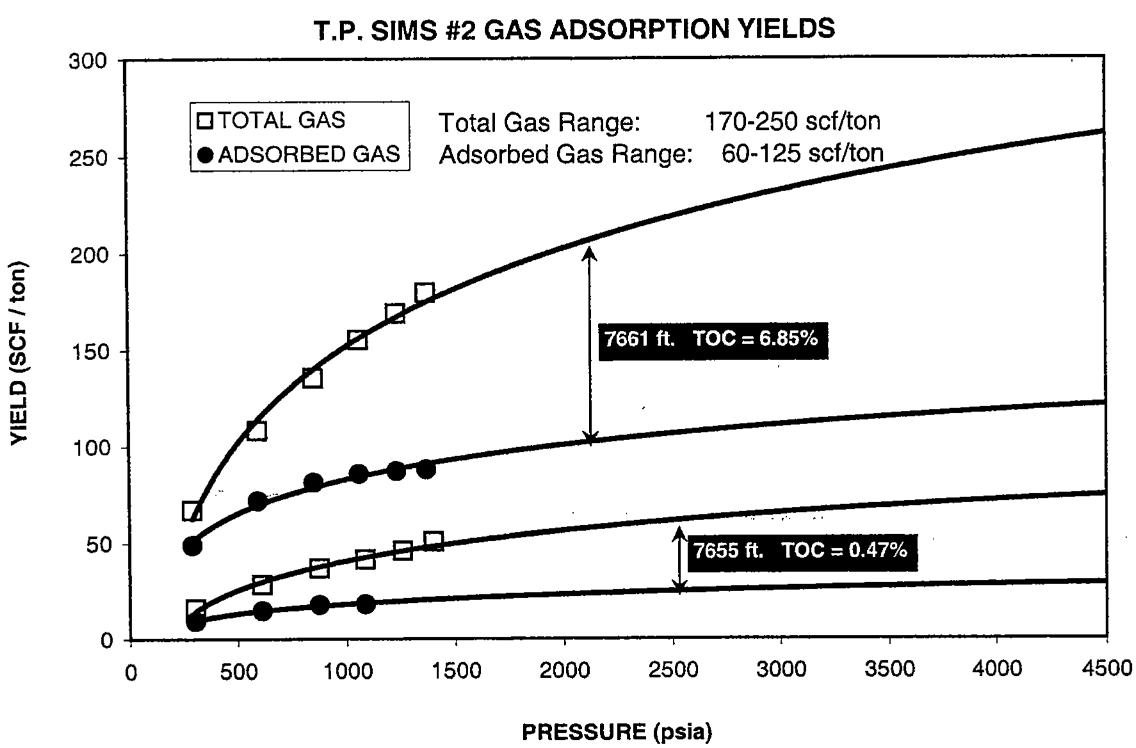


Figure 10. Adsorption test results for a lean and organic rich Barnett Shale samples refit from adsorption data in the Gas Research Institute (1991) report and projected to 3,800 psi, the typical reservoir pressure in a Barnett Shale well.

It was also noted from a gas database that a relationship exists between gas calorific value (in BTUs) and gas dryness (Fig. 11). Gas dryness is defined as the ratio of methane to the sum of methane, ethane, propane, and butane (C_1, C_2, C_3, i-C_4, and n-C_4 gases, respectively). These data show a 0.78 least-squares correlation despite the gases containing variable amounts of carbon dioxide and nitrogen that lower the BTU values. Because pure methane has a BTU value of 978, any gas having greater than 90% gas-dryness ratio is inferred to

TABLE 2.—Mineralogy and Selected TOC Values from the Mitchell Energy W. C. Young #2 Well

Depth (feet)	Total clay	Quartz	K Feldspar	Plagioclase	Calcite	Dolomite	Pyrite	Apatite	Total	TOC
6,090.50	16	10	0	0	55	17	2	0	100	nd
6,920.00	35	44	1	2	4	7	4	3	100	4.84
6,936.00	43	30	1	2	2	3	6	13	100	nd
6,944.00	4	13	0	1	54	3	11	14	100	nd
6,953.50	37	40	0	3	4	1	7	8	100	nd
6,964.00	4	10	0	3	78	2	3	0	100	nd
6,973.00	38	37	2	6	3	2	5	7	100	nd
6,985.00	42	38	1	3	2	3	8	3	100	nd
7,001.00	23	32	0	4	30	4	4	3	100	nd
7,006.00	37	34	1	6	10	6	2	4	100	nd
7,007.00	0	4	0	2	71	1	21	1	100	nd
7,014.00	31	42	1	4	7	7	6	2	100	nd
7,022.50	20	33	0	5	3	0	10	29	100	nd
7,026.00	48	33	2	6	0	1	8	2	100	nd
7,030.50	7	4	1	4	5	70	9	0	100	nd
7,033.00	48	36	4	5	0	1	4	2	100	4.42
7,045.00	37	40	2	4	2	8	5	2	100	nd
7,061.60	41	42	2	3	3	3	5	1	100	nd
7,065.00	45	40	1	4	0	2	6	2	100	nd
7,075.00	37	43	1	4	3	3	6	3	100	nd
7,081.00	18	17	0	4	2	55	4	0	100	1.88
7,086.00	54	31	1	4	0	0	7	3	100	5.16
7,095.00	46	34	0	4	0	5	9	2	100	nd
7,108.00	32	31	3	4	2	20	6	2	100	5.78
7,118.00	51	28	5	6	0	0	7	3	100	nd
7,126.00	37	47	2	4	0	1	5	4	100	6.53
7,135.00	48	33	3	5	0	3	7	1	100	nd
7,141.00	45	34	1	3	3	4	6	4	100	nd
7,150.00	50	34	2	4	0	0	8	2	100	nd
7,156.50	21	23	1	2	42	3	4	4	100	nd

Note: Mineralogy data from GRI (1991).

be in the dry-gas window. Gases having 80% gas dryness are inferred to be in the condensate–wet-gas window, and gases with less than 80% gas dryness (i.e., they are wetter) are in the oil window. This inferred relationship *only applies* to gases in a self-sourcing gas habitat such as the Barnett Shale. Thus, from these data, another thermal maturity parameter is available for assessment of gas risk and one that can be used prior to receiving vitrinite-reflectance data.

RISKING SHALE GAS PROSPECTS, PLAYS, OR BASINS BASED ON GEOCHEMICAL DATA

A basic approach to performing shale gas risking assessments is to determine and map organic richness, kerogen type, kerogen transformation, various thermal-maturity parameters, gas contents, and gas yields. To complete this, only TOC, Rock-Eval, vitrinite-reflectance, and gas data are needed. However, there may be conflicts in the data due to a variety of circumstances such as poor vitrinite-maceral yields, misidentification of indigenous vitrinite populations, bitumen staining (Landis and Castaño, 1995), unreliable T_{max} data, and so forth. The first and most important step is to understand the type of petroleum system that is present. For example, parameters that point to success in the thermogenic Barnett Shale gas play will not work in the Antrim Shale gas play, which is a biogenic gas play. In addition, some basic assessments must be made as to what products are generated at a given thermal maturity. Thus, a basic investigation and understanding of the petroleum system with respect to

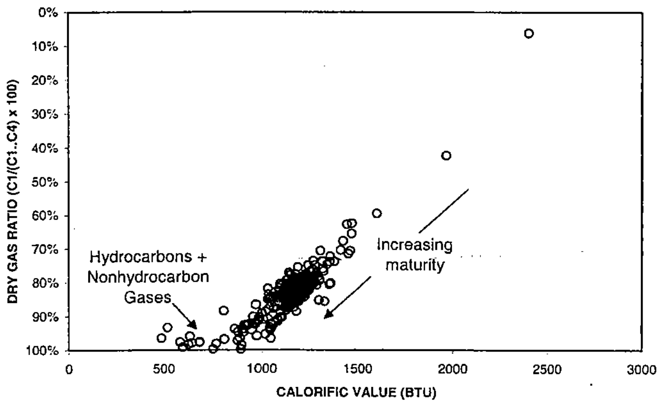


Figure 11. Relationship of calorific value of gases from the Ft. Worth Basin to gas-dryness ratio. Gas dryness can be determined from either production gases, mud gases, or cuttings headspace gases, and can be used to infer thermal maturity of Barnett Shale. Approximately 80% gas dryness is required for condensate-wet gas window thermal maturity, and >90% for dry gas (lowest BTU hydrocarbon gas).

source-rock thermal maturity, its extent of conversion, the timing of generation and expulsion, and oil and gas analyses must be undertaken. A large dataset also helps integrate and evaluate specific prospect data.

Once this is undertaken, conflicts in the data may arise. One method of assessing these data is a simple polar plot (Hill plot) setting specific guidelines for the gas window. In the case of the Barnett Shale, the following risking minimum values for prospective gas production are suggested (Fig. 12):

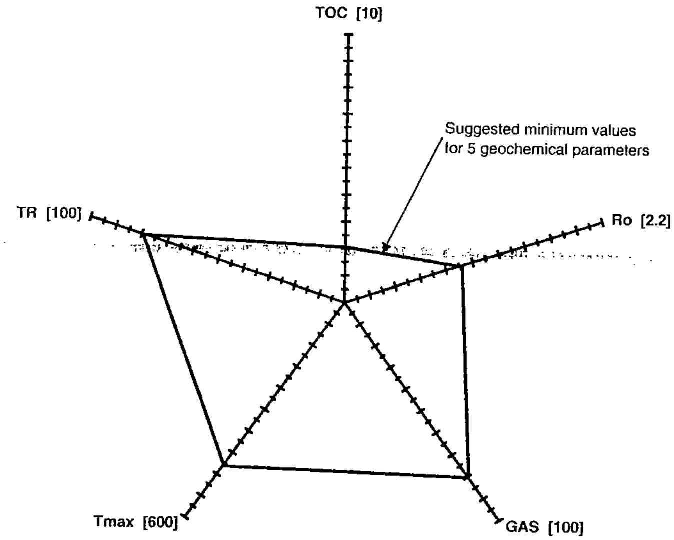
TOC:	2.00%
TR:	80%
T_{max}:	455°C
VR_o:	1.0%
Gas dryness:	80%

Critical cross-over points exist that need to be more accurately determined, such as vitrinite reflectance; most geochemists would argue for at least 1.20% VR_o, but there is a dependency on sample type (i.e., cuttings vs. core). Thus, the range of 1.00–1.20% VR_o could be considered a questionable maturity range for finding productive gas.

IDENTIFYING SWEET SPOTS

The phrase "sweet spots" is used by many in two different ways: (1) to identify the best geographic areas within a basin for gas, and (2) to identify the best formation zones in a given well to complete. Here, we prefer the terminology "fairway" to describe basin wide trends. Thus, the best geographic areas for gas production would be termed gas fairways. The term sweet spot is then used to describe the most productive zones within the formation in a given well, or depth interval.

Well logging of mud gases and desorbed gases from cuttings or core is an effective tool for identifying the best zones to complete. Yields will vary with TOC and



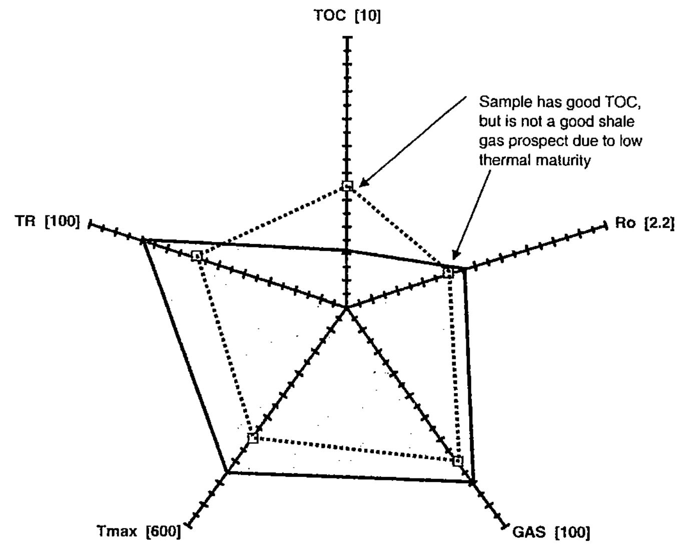


Figure 12. Geochemical risking parameters for thermogenic shale gas suggested from Barnett Shale studies. Samples exceeding these minimum values suggest a good prospect for shale gas production in a thermogenic gas play.

with lithology. The Barnett Shale is principally siliceous shale, but also contains clay-rich shales, cherts, and dolomitic lithologies (Gas Research Institute, 1991; Henk and Breyer, 2000). These lithofacies variations (lithology and TOC) will influence producible yields, whether oil and gas in lower thermal maturity prospects or high-BTU to low-BTU gas in higher-thermal–maturity prospects. In addition, it has been reported that the most highly fractured Barnett Shale intervals in and near the Newark East Field have among the poorest hydrocarbon yields for gas (Bowker, 2002, 2003).

Quantitative analysis of mud gases, headspace gases in canned cuttings, and production gases has shown that gas dryness is an excellent indicator of thermal maturity and provides yields of gas per unit of rock. Of course, adsorption tests on core and desorption tests on sidewall cores (SWC) corroborate and enhance the interpretation of these analyses. Mud gases will always be drier than canned-cuttings gases due to higher rates of desorption and diffusion of dry gas (methane) out of the reservoir into the well bore (lost gas) and retention of the wetter gases (ethane, propane, and butanes) or gas that will desorb through time (desorbed gas). There will also be solubility differences that may affect these differences. Back calculation from longer-term desorption testing can be used to calculate lost gas, but quantitative mud-gas yields provide a direct indication of lost gas. In many reservoir types, the mud gas is more representative of the actual products in the reservoir (e.g., unconsolidated sands of the Gulf of Mexico; Patience, 2003). However, when evaluation of low-permeability shales is undertaken, both mud gas and desorbed gas must be quantitatively determined. In addition, there is additional gas yield when the shale is completed by water- or proppant-fracturing operations, and this is evaluated by crushing the sample and measuring the released gas.

Gas yields from mud gas and desorbed gases from canned cuttings samples can be made available to assess well-specific sweet spots for the best productivity of oil, wet gas, or dry gas. This is a simple assessment of gas dryness from a ratio of methane to the total gas consisting of methane, ethane, propane, and butanes $[C_1/(C_1-C_4)]$. This classical approach is quite effective in evaluating different horizons for producibility characteristics (Pixler, 1969). A correlation of gas dryness with thermal maturity and the calorific values for Barnett produced oil or gas was demonstrated by Jarvie and others (2003).

CONCLUSIONS

The Barnett Shale is organic rich, but TOC values in the dry-gas zone are decreased by about 36% due to loss of carbon from kerogen in the form of hydrocarbons. Likewise, in the gas-generation window, the kerogen type will only reflect the present-day potential of the shale, which is gas prone for any thermally mature rock. However, the original potential of the Barnett Shale, as determined from thermally immature samples from outcrop and well samples, firmly establishes it as a Type II oil-prone, marine kerogen with an original HI value of about 487 mg HC/g TOC. The Barnett Shale generates gas in the oil-generation window, but this only constitutes about 30% of the total hydrocarbons generated with the rest being liquids (C_5 +). Because of the low permeability, limited porosity, and retentive capacity of the Barnett Shale, some hydrocarbons are retained during primary migration. This leads to retention of oil until it is cracked to gas.

Burial- and thermal-history models suggest that the Barnett Shale entered the gas-generation window approximately 250 Ma; it is thought that little, if any, additional generation has occurred in the last 250 million years. There are assumptions in the models that may allow more gas generation in the last 25 million years, but the present model shows much earlier gas generation.

Gas data may be used to predict thermal maturity, as shown by correlation of gas dryness to BTU content of produced gases in the basin.

The Barnett Shale has very high gas yields ranging from 170 to 250 scf/ton based on corrected methane adsorption data from the T. P. Sims #2 well. This gas is present as 55% free gas and 45% sorbed gas, on average. However, there is considerable variability in these yields depending on the interval analyzed within the Barnett Shale. This variability is hypothesized to be due to variations in porosity and mineralogy as the TOC values are quite similar in most of the samples. However, a low TOC sample (0.47%) included in the analysis certainly does have the lowest gas yield, but TOC does not explain the variable gas yields in the organic rich zones that average 4.45% TOC with small variance.

Various geochemical parameters can be used to assess a prospect for its gas potential based on the thermal maturity of a basin, lease area, or prospect. These include TOC, TR and T_{max} data (derived from Rock-Eval analysis), vitrinite reflectance, and gas data. Gas isotopes and condensate/oil chemistry can also be used to map out maturity regimes.

ACKNOWLEDGMENTS

Much advance to the Ft. Worth Basin work has transpired in the past year by a collaborative effort between Humble and geochemists and geologists from the U.S. Geological Survey (USGS) in Denver. These people include Paul Lillis, Augusta Warden, and Dave King at the USGS. Also my colleagues at Humble contributed immensely to this effort, especially Jack D. Burgess and a consultant, Brenda L. Claxton.

REFERENCES CITED

Bowker, K. A., 2002, Recent developments of the Barnett Shale play, Fort Worth Basin, *in* Law, B. E.; and Wilson, M. (eds.), Innovative gas exploration concepts symposium: Rocky Mountain Association of Geologists and Petroleum Technology Transfer Council, Denver, 16 p.

______ 2003, Recent development of the Barnett Shale play, Fort Worth Basin: West Texas Geological Society Bulletin, v. 42, no. 6, 8 p.

Espitalie, J.; Madec, M.; and Tissot, B., 1984, Geochemical logging, *in* Voorhees, K. J. (ed.), Analytical pyrolysis—techniques and applications: Butterworth, Boston, p. 276–304.

Gas Research Institute, 1991, Formation evaluation technology for production enhancement: log, core, and geochemical analyses in Barnett Shale, Mitchell Energy Corp. Thomas P. Sims No. 2, Wise County, Texas, gas shale project area: Report for GRI Contract No. 5086-213-1390.

Henk, F. "Bo"; and Breyer, J. T., 2000, Lithofacies, petrography, and geochemistry of the Barnett Shale in conventional core and outcrop: Barnett Shale Symposium, Fort Worth, Texas, Sept. 28, 2000, oral presentation.

Hill, R. J.; Jarvie, D. M.; Pollastro, R. M.; Bowker, K. A.; and Claxton, B. L., 2004, Geochemistry of an unconventional gas prospect: the Barnett Shale gas model: Goldschmidt Conference, Copenhagen, Denmark, June 7–11, 2004, oral presentation.

Jarvie, D. M., 1991, Total organic carbon (TOC) analysis, *in* Merrill, R. K. (ed.), Source and migration processes and evaluation techniques: American Association of Petroleum Geologists, Tulsa, Oklahoma, Treatise of Petroleum Geology, Handbook of Petroleum Geology, p. 113–118.

______ 2000, Assessment and prediction of hydrocarbon generation of the Barnett Shale: Barnett Shale Symposium, Ft. Worth, Texas, Sept. 28, 2000, oral presentation.

Jarvie, D. M.; and Lundell, L. L., 1991, Hydrocarbon generation modeling of naturally and artificially matured Barnett Shale, Ft. Worth Basin, Texas: Southwest Regional Geochemistry Meeting, The Woodlands, Texas, Sept. 8–9, 1991.

Jarvie, D. M.; Claxton, B. L.; Henk, F. "Bo"; and Breyer, J. T., 2001, Oil and shale gas from the Barnett Shale, Ft. Worth Basin, Texas: American Association of Petroleum Geologists Bulletin, v. 85, no. 13 (Supplement), p. A100.

Jarvie, D. M.; Hill, R. J.; Pollastro, R. M.; Wavrek, D. A.; Bowker, K. A.; Claxton, B. L.; and Tobey, M. H., 2003, Evaluation of unconventional natural gas prospects: the Barnett Shale fractured shale gas model: 21st International Meeting on Organic Geochemistry, Krakow, Poland, Sept. 8–12, 2003, poster presentation.

Landis, C. R.; and Castaño, J. R., 1995, Maturation and bulk chemical properties of a suite of solid hydrocarbons: Organic Geochemistry, v. 22, p. 137–149.

Magoon, L. B.; and Schmoker, J. W., 2000, The total petroleum system: the natural fluid network that constrains the assessment unit, *in* U.S. Geological Survey world petroleum assessment 2000; Description and results: U.S. Geological Survey Digital Data Series DDS-60, p. PS1–PS20.

Montgomery, S. L.; Jarvie, D. M.; Bowker, K. A.; and Pollastro, R. M., 2005, Mississippian Barnett Shale, Fort Worth Basin, north-central Texas: gas-shale play with multi–trillion cubic foot potential: American Association of Petroleum Geologists Bulletin, v. 89, p. 155–175.

Patience, R., 2003, Comparison of subsurface gas data from different sampling methods [abstract]: 21st International Meeting on Organic Geochemistry, Krakow, Poland, Sept. 8–12, Book of Abstracts Part II, p. 7.

Pixler, B. O., 1969, Formation evaluation by analysis of hydrocarbon ratios: Journal of Petroleum Technology, December 1969, p. 665–670.

Pollastro, R. M., 2003, Geological and production characteristics utilized in assessing the Barnett Shale continuous (unconventional) gas accumulation, Barnett-Paleozoic Total Petroleum System, Fort Worth basin, Texas: Barnett Shale Symposium, Ellison Miles Geotechnology Institute at Brookhaven College, Dallas, Texas, Nov. 12–13, 2003, 6 p.

Pollastro, R. M.; Hill, R. J.; Jarvie, D. M.; and Henry, M. E., 2003, Assessing undiscovered resources of the Barnett-Paleozoic Total Petroleum System, Bend Arch–Fort Worth Basin Province, Texas: Unpublished paper distributed at the American Association of Petroleum Geologists Southwest Section Meeting, Fort Worth, Texas, March 1–4, 2003, 18 p.

Pollastro, R. M.; Hill, R. J.; Jarvie, D. M.; and Adams, C., 2004, Geologic and organic geochemical framework of the Barnett-Paleozoic Total Petroleum System, Bend Arch–Fort Worth Basin, Texas [abstract]: American Association of Petroleum Geologists Annual Convention, Abstracts Volume, v. 13, p. A113.

Facies Distribution and Hydrocarbon Production Potential of Woodford Shale in the Southern Midcontinent

John B. Comer
Indiana Geological Survey
Bloomington, Indiana

ABSTRACT.—Woodford Shale is a prolific hydrocarbon-source rock throughout the southern Midcontinent of the United States, and in south-central Oklahoma it produces both oil and natural gas. The characteristic and dominant Woodford lithology is black shale, but chert, siltstone, sandstone, dolostone, and light-colored shale are common locally. These mostly fine-grained sediments accumulated in an epeiric sea that lay along the western continental margin of North America in the dry tropics near 15° south latitude. Depositional processes included prolonged periods of pelagic sedimentation punctuated by episodes of fine-grained mixed siliciclastic-carbonate deposition from storm-generated bottom flows. In general, proximal lithofacies and basin depocenters contain more silt and sand, and distal lithofacies contain more chert. The highest concentrations of organic carbon are found in intermediate settings remote from clastic-source areas and bypassed by bottom flows. High concentrations of marine organic matter coexist with abundant biogenic silica, indicating that high biological productivity in surface waters was supported mainly by dynamic upwelling.

The primary sites of hydrocarbon generation coincide mostly with the principal depocenters of the Delaware and Anadarko Basins; however, mature source beds are found in adjacent provinces. Mass-balance calculations indicate that on the order of 830×10^{12} ft^3 of natural gas and 250×10^9 bbl of oil reside in Woodford Shale in Oklahoma, northwestern Arkansas, West Texas, and southeastern New Mexico. Producing this resource is feasible where the subcrop contains competent lithofacies that are highly fractured (e.g., chert, sandstone, siltstone, dolostone). Areas having the greatest hydrocarbon potential and most favorable lithologies include (1) the Nemaha Uplift (chert, sandstone, dolostone), (2) Marietta-Ardmore Basin (chert), (3) southern flank of the Anadarko Basin along the Wichita Mountain Uplift (chert), (4) frontal zone of the Ouachita Tectonic Belt in Oklahoma (chert), and (5) the Central Basin Platform and Pecos Arch in West Texas and New Mexico (chert and siltstone). In much of the southern Midcontinent, the Woodford Shale is currently in the oil-or-gas–generation window. Thus, fracture porosity would be continuously fed by hydrocarbons generated in the enclosing source rocks. Petroleum systems such as this typically produce at low to moderate flow rates for many decades.

INTRODUCTION

This report presents a regional overview of the potential for producing oil and natural gas from Woodford Shale in the southern Midcontinent. The focus of the report is on Anadarko and Permian Basin depocenters and adjacent geologic provinces (Fig. 1) where major oil and gas reserves are well known and extensively exploited. This study uses data on the source-rock quality, thermal maturity, stratigraphy, lithology, and facies distribution to evaluate the potential for hydrocarbon production. Much of the data and supporting documentation comes from an extensive database that includes descriptions of 29 cores and 46 outcrops, 414 organic carbon analyses, 167 vitrinite-reflectance measurements, and 164 analyses of the elemental composition of isolated kerogen. These data are summarized in Comer and Hinch (1987) and Comer (1991, 1992).

The Woodford Shale is an attractive target for unconventional oil and gas exploration and development because it is a world-class source rock that is widely distributed throughout the southern Midcontinent and locally produces oil and gas from fractured intervals (Comer and Hinch, 1987; Cardott, 2005 [this volume]). Drilled intervals commonly yield shows of oil from cuttings and cores and produce a gas response on mudlogs

Comer, J. B., 2005, Facies distribution and hydrocarbon production potential of Woodford Shale in the southern Midcontinent, *in* Cardott, B. J. (ed.), Unconventional energy resources in the southern Midcontinent, 2004 symposium: Oklahoma Geological Survey Circular 110, p. 51–62.

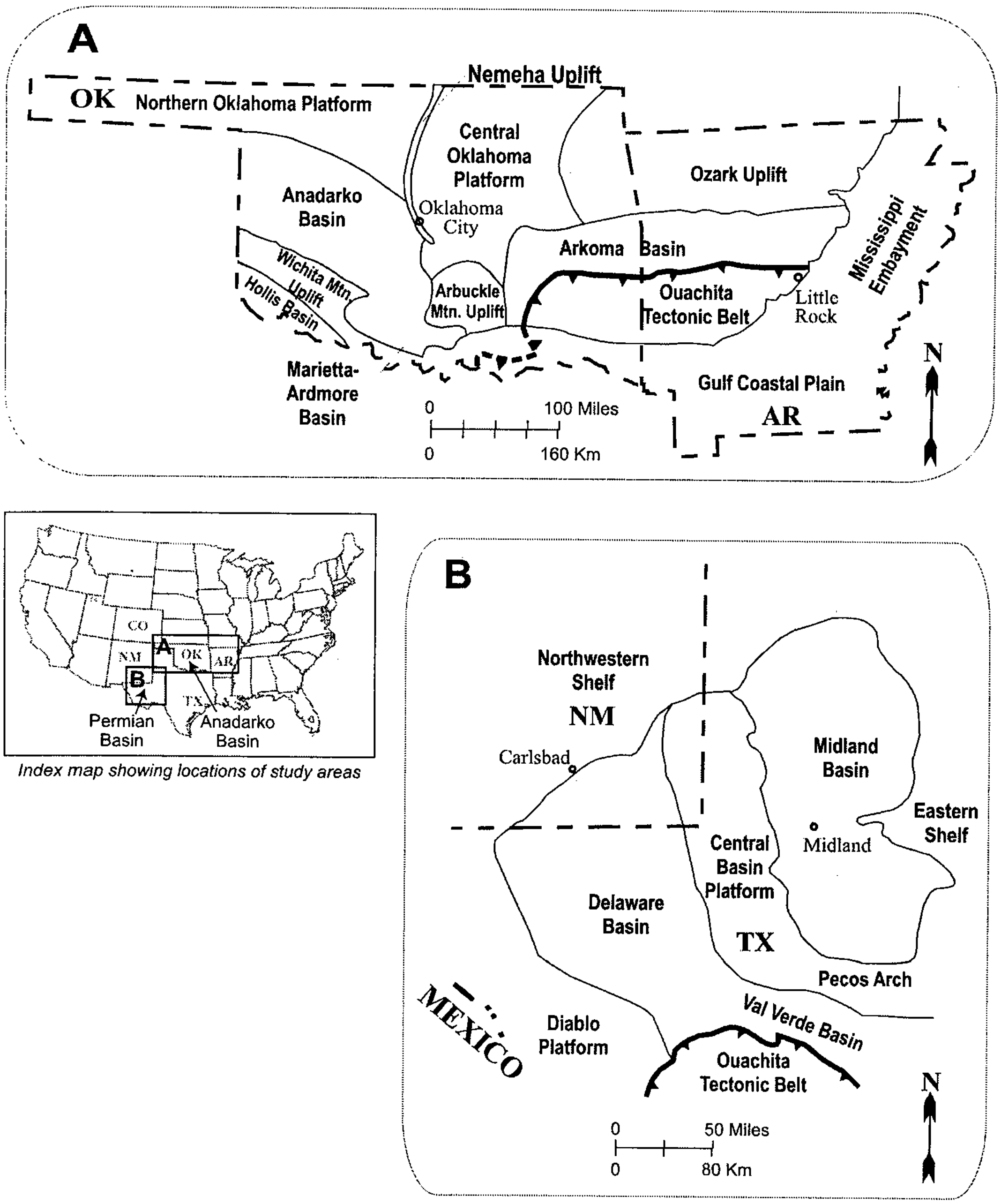


Figure 1. Map showing geologic provinces discussed in this report. (A) Anadarko Basin region modified from Comer (1992). (B) Permian Basin region modified from Comer (1991).

confirming that Woodford Shale typically contains significant concentrations of crude oil and natural gas. This report presents a regional model for exploration and estimates the volumes of oil and gas contained in this unconventional reservoir.

REGIONAL SOURCE-ROCK QUALITY

Numerous oil-to-rock correlation studies document that Woodford Shale is a prolific source of oil throughout the southern Midcontinent (Brenneman and Smith, 1958; Hunt, 1961; Welte and others, 1975; Lewan and others, 1979; Winters and others, 1983; Iztan, 1985; Comer and Hinch, 1987; Reber, 1988; Burruss and Hatch, 1989; Philp and others, 1989; Jones and Philp, 1990; Comer, 1992; Landis and others, 1992; Wang and Philp, 1997). Woodford Shale commonly contains very high concentrations of organic matter (Curiale, 1983; Sullivan, 1985; Comer, 1991, 1992; Landis and others, 1992; Wang and Philp, 1997), with mean organic carbon concentrations of 5.6 wt % for the Anadarko Basin region (Fig. 1A), 3.8 wt % for the Permian Basin region (Fig. 1B), and 5.1 wt % for both regions combined. Organic carbon concentrations in individual samples range from <0.1 wt % (i.e., below the detection limit) in some chert beds (Comer, 1992) to 35 wt % in black shale (Landis and others, 1992). Woodford Shale contains predominantly oil-prone type-II kerogen (Comer and Hinch, 1987; Cardott, 1989; Comer, 1991, 1992; Landis and others, 1992) representing a wide range of thermal maturities from marginally immature to metamorphic ($R_0 = 0.37 - 4.89\%$) (Cardott, 1989; Comer, 1992). As much as 85% of the oil produced in central and southern Oklahoma is estimated to originate in Woodford Shale (Jones and Philp, 1990).

REGIONAL STRATIGRAPHY

The Woodford Shale is mostly Late Devonian (Frasnian–Famennian) in age but ranges from Middle Devonian (Givetian) to Early Mississippian (Kinderhookian) (Hass and Huddle, 1965; Amsden and others, 1967; Amsden, 1975, 1980). In the southern Midcontinent, age-equivalent strata include the Chattanooga Shale, Misener Sandstone, Sylamore Sandstone, middle division of the Arkansas Novaculite, upper part of the Caballos Novaculite, Houy Formation, Percha Formation, and Sly Gap Formation (King and others, 1945; Stevenson, 1945; Laudon and Bowsher, 1949; Graves, 1952; Cloud and others, 1957; Huffman, 1958; Hass and Huddle, 1965; Amsden and others, 1967). These units were deposited over a major regional unconformity (Galley, 1958; Amsden and others, 1967; Freeman and Schumacher, 1969; Ham and Wilson, 1967; Ham, 1969; Amsden and Klapper, 1972) and represent diachronous onlapping sediments (Amsden and others, 1967; Amsden and Klapper, 1972; Freeman and Schumacher, 1969; Galley, 1958; Ham, 1969; Ham and Wilson, 1967). In the southern Midcontinent these units are the stratigraphic record of worldwide Late Devonian marine transgression.

LITHOLOGY AND DISTRIBUTION

The Woodford Shale and age-equivalent strata comprise an assemblage of lithologies whose composition, fabric, and distribution provide the clues to decipher depositional setting and predict hydrocarbon production potential. The predominant lithology is black shale which constitutes the most widespread and characteristic Woodford facies. Other common lithologies include chert, siltstone, sandstone, dolostone, and light-colored shale (Harlton, 1956; Amsden and others, 1967; Amsden, 1975, 1980; Comer, 1991, 1992).

Parameters used to identify facies with hydrocarbon production potential include fracture abundance and type, organic carbon concentration, and thermal maturity. The greatest likelihood of producing hydrocarbons from Woodford Shale is where the formation is highly fractured, organic rich, and thermally mature. Fractures are most abundant in tectonically disturbed zones, especially those affected by orogeny such as the Ouachita Tectonic Belt and by rifting such as the southern Oklahoma and Delaware Basin aulacogens. Locations where these fracture trends coincide with organic-rich, thermally mature Woodford Shale are optimum targets for the exploration and development of unconventional hydrocarbon resources.

The distribution of organic-rich Woodford facies (Fig. 2) is the result of Late Devonian paleogeography and depositional processes. During the Late Devonian, the southern Midcontinent lay along the western margin of North America in the warm dry tropics near 15° south latitude (Comer, 1991; Heckel and Witzke, 1979). As described by Comer (1991), Woodford deposition began as sea level rose, drowning marine embayments in what are now the deepest parts of the Delaware, Val Verde, Anadarko, and Arkoma Basins and advanced over subaerially eroded, dissected terrane consisting mostly of Ordovician to Middle Devonian carbonate rocks. The broad epeiric sea that formed had irregular bottom topography and scattered, low-relief land masses which supported little vegetation and few rivers. The high concentrations of organic carbon in the black shale facies resulted both from high biological productivity in near-surface waters and from excellent preservation on the sea floor. Oceanic water from an area of coastal upwelling flowed into the expanding epeiric sea and maintained a thriving normal marine biota in the upper levels of the water column. Net evaporation locally produced hypersaline brine, and strong density stratification developed that restricted vertical circulation and resulted in bottom waters depleted in oxygen. Pelagic debris from the thriving biomass slowly settled to a stagnant sea floor where large concentrations of organic- and sulfide-rich mud accumulated. Deposition of organic-rich mud ended because marine transgression ceased and oceanographic patterns changed, thus halting the strong net flow of ocean water onto the craton and forcing deep circulation throughout most of the epeiric sea.

Organic-poor siltstone facies represent episodic bottom flows triggered by frequent storms and occasional earthquakes (Comer, 1991). Bottom flows supplied silt and mud to proximal shelves and basin depocenters and caused much resedimentation throughout the epeiric sea. Silt-sized silicate minerals (quartz, feldspar, muscovite) are most abundant in proximal settings along the northwestern shelf and in the northwestern part of the Anadarko Basin (Fig. 1). These provinces are nearest the southern end of the Transcontinental Arch which was the dominant topographic high in western North America during the Late Devonian (Poole and others, 1967; Poole, 1974; Heckel and Witzke, 1979). Terrigenous detritus derived from this emergent source area and contemporaneous dolomitic silt from intrabasinal shoals were carried by bottom flows into basinal depocenters bypassing distal highs such as the Central Basin Platform, Pecos Arch, and Nemaha Uplift (Comer, 1991, 1992). Consequently, organic carbon concentrations on these distal highs are greater than organic carbon concentrations in proximal settings and basin depocenters where mixed siliciclastic-dolomitic silt is more abundant.

Radiolarian chert beds are common along distal margins, slopes, and troughs in the Ouachita Tectonic Belt, Marietta-Ardmore Basin, and Arbuckle Mountain Uplift. The abundance of radiolarians and the thickness of radiolarian chert beds increase toward the open ocean, and in the central area and core area of the

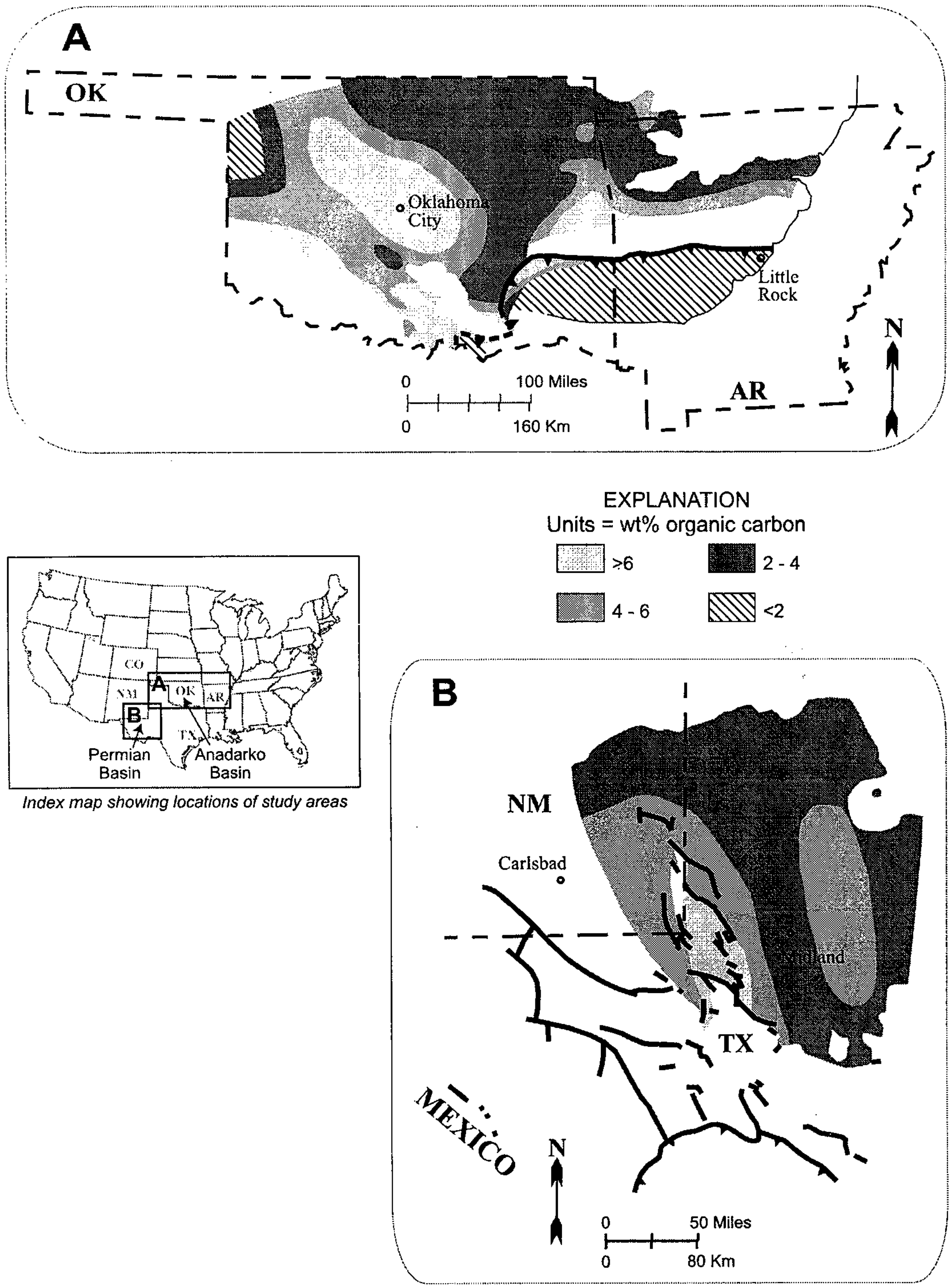


Figure 2. Map showing organic carbon distribution in Woodford Shale and age-equivalent units in the (A) Anadarko and (B) Permian Basin regions. Maps modified from Comer (1991, 1992).

Ouachita Tectonic Belt almost pure radiolarian chert is the dominant facies. These extensive deposits of biogenic chert are the best evidence of widespread coastal upwelling along the western continental margin during the Late Devonian (Park and Croneis, 1969; Lowe, 1975; Parrish, 1982). The abundance of biogenic chert and marine organic matter indicates that there was high biologic productivity in the near-surface waters of the epeiric sea, and preservation of the organic carbon and the abundance of pyrite in Woodford Shale indicate that bottom waters were stagnant and anoxic for prolonged periods of time (Comer, 1991). Along distal highs and along the craton margin landward from the deep Ouachita trough, high concentrations of radiolarian chert coincide with high concentrations of organic carbon. Fields that produce oil from fractured Woodford

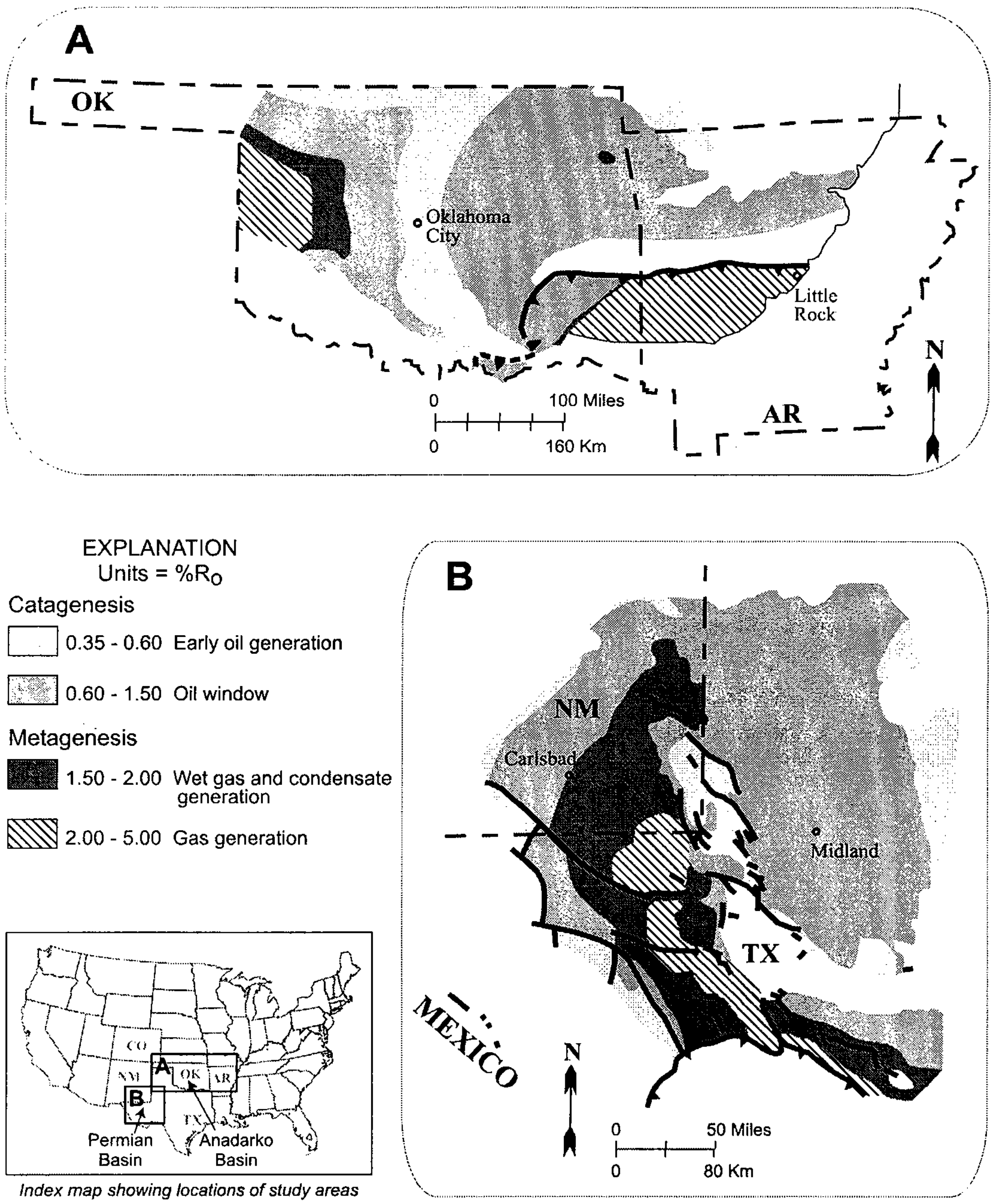


Figure 3. Map showing thermal maturity of Woodford Shale and age-equivalent units in the (A) Anadarko (Comer, 1992) and (B) Permian Basin regions. Patterns are based on the reflectance of vitrinite (%R_o).

Shale are completed in these organic-rich chert intervals (Comer and Hinch, 1987). Chert is dense and brittle and is the optimum Woodford lithology for developing and maintaining open natural fracture systems that effectively accumulate and transmit hydrocarbons.

Thermal maturity trends (Fig. 3) closely follow Woodford structure with the highest maturities occurring in the deep basins and in orogenic belts, and the lowest maturities occurring along structural highs (Cardott and Lambert, 1985; Houseknecht and Matthews, 1985; Carr, 1987; Cardott, 1989; Comer, 1991, 1992; Houseknecht and others, 1992; Landis and others, 1992). Woodford Shale reaches its highest thermal maturity in the Anadarko, Delaware, and Arkoma Basins where it is most deeply buried and in the Ouachita Tectonic Belt where stratigraphically equivalent beds locally have been metamorphosed. Intermediate maturities occur in shelf settings and the lowest maturities occur on structural highs such as the Central Basin Platform, Pecos Arch, Nemaha Uplift, Arbuckle Mountain Uplift, and the frontal zone of the Ouachita Tectonic Belt. In the deep basins Woodford Shale is in the gas generation window, whereas in the shelf and platform settings Woodford Shale is in the oil generation window (Comer, 1991, 1992). Thermally mature fractured Woodford Shale intervals where oil or gas generation is actively

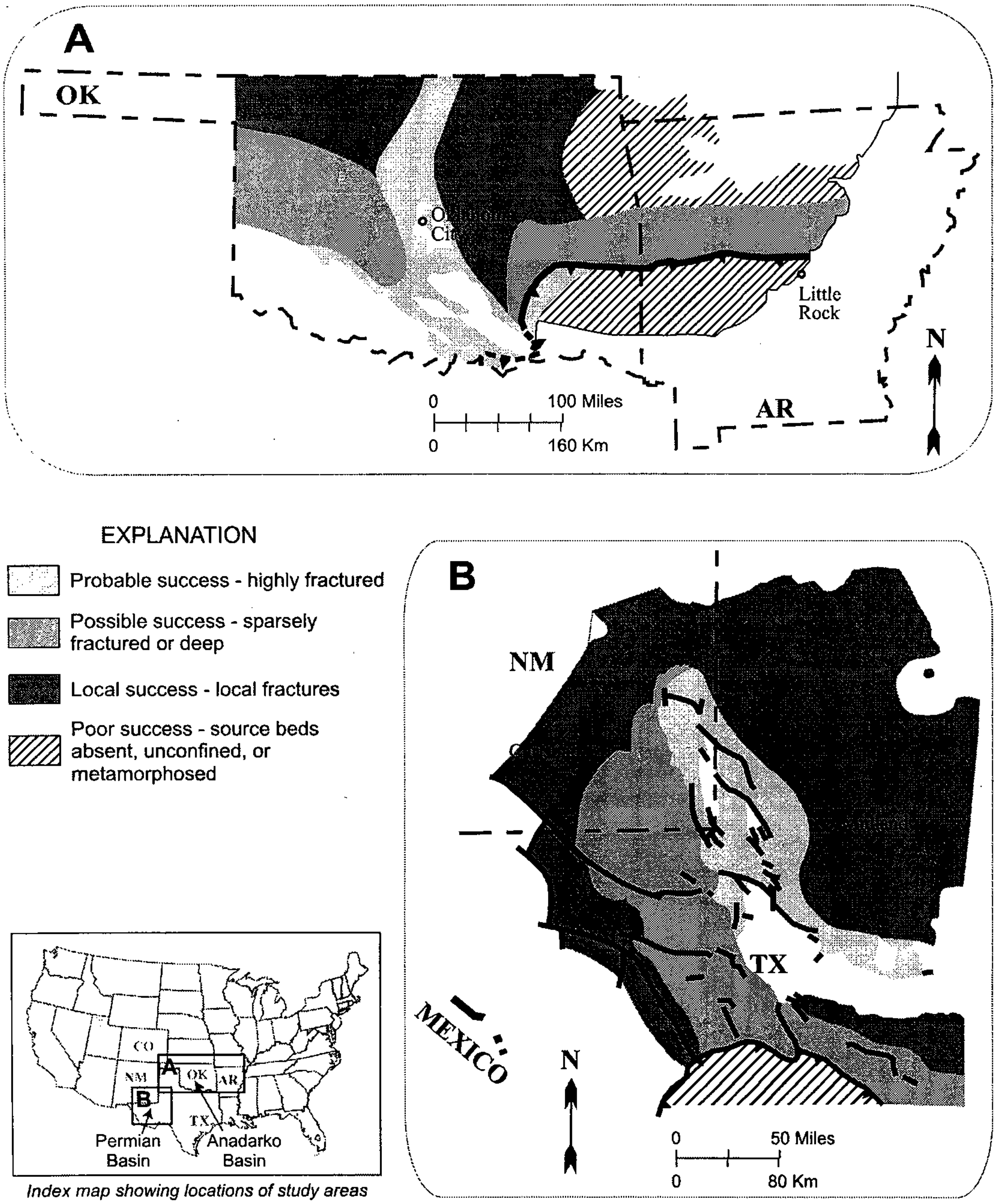


Figure 4. Map showing hydrocarbon production potential of Woodford Shale and age-equivalent units in the (A) Anadarko and (B) Permian Basin regions.

occurring are optimum locations for hydrocarbon production because the fracture networks would be fully charged with the generated hydrocarbons.

POTENTIAL PRODUCTION TRENDS

There is significant potential for unconventional hydrocarbon production from Woodford Shale in areas where large amounts of oil or gas have been retained in the formation and where natural fracture networks are likely to be found. Figure 4 shows potential production trends which are qualitatively ranked based on the probability that naturally fractured, mature organic-rich beds of Woodford Shale are present in the subsurface. The trends are designated as areas of probable, possible, local, and poor success as follows. Areas of probable success are those in which beds of highly fractured Woodford are likely and where the formation is shallow enough both for economic drilling and for open fracture networks to persist. Areas of possible success are those in the deep basins where drilling would be expensive and fracture networks more constricted, but where huge volumes of gas are likely to reside. Areas of local success are those in shelf settings where Woodford Shale is relatively thin but thermally mature and at a relatively shallow depth. Areas of poor success are those in which the formation is exposed at the surface or is shallow and unconfined, and where Upper Devonian strata have been metamorphosed or have very low organic carbon content.

TABLE 1.—Data Used for Calculating Reservoir Mass (equation 4)

Area name	Thickness (km)	Area (km^2)	Volume (km^3)	Density MT/km^3	Mass MT x 10^{12}
Anadarko Basin					
Probable success	0.030	44,000	1,300	2.4E+09	3.1
Possible success	0.061	56,000	3,400	2.4E+09	8.2
Local success	0.015	56,000	840	2.4E+09	2.0
Permian Basin					
Probable success	0.030	20,000	600	2.4E+09	1.4
Possible success	0.061	22,000	1,300	2.4E+09	3.1
Local success	0.015	60,000	900	2.4E+09	2.2

Note: Area name designations are shown in Figure 4.
Values are rounded to two significant figures.

ESTIMATION OF RESOURCE POTENTIAL

The estimations of resource potential presented here are based on the assumption that oil and gas in the Woodford Shale are indigenous. With this assumption, we can use conventional source rock data, including organic carbon concentration, organic hydrogen concentration, organic matter type, and thermal maturity, together with facies volumes (thickness times area), to calculate gross estimates for oil-in-place and gas-in-place.

The observation that the end products of thermal maturation are methane (CH_4) and a graphitic carbon residue (Tissot and Welte, 1984; Hunt, 1996) document that source rocks contain excess organic carbon. Thus, the volume of hydrocarbons generated in a source rock is limited by the amount of hydrogen available in the system. Although hydrogen from inorganic sources such as water and hydrous mineral phases may contribute and the exchange of hydrogen between kerogen and water has been documented experimentally (Lewan, 1997; Schimmelmann and others, 1999), hydrogen exchange reactions do not appear to result in massive increases in the amount of hydrogen available for hydrocarbon generation (Tissot and Welte, 1984; Hunt, 1996). Similarly, losses of hydrogen from the organic fraction in the form of H_2O and H_2 molecules do not represent large losses of organic hydrogen mass during the main stages of oil and gas generation (Tissot and Welte, 1984; Hunt, 1996). Because large amounts of water are eliminated from organic matter by reactions of H- and OH-bearing organic molecules before a source bed enters the oil window (Tissot and Welte, 1984; Hunt, 1996), all of the organic data in this report represent kerogen that has matured to or beyond the inflection point on the van Krevelen diagram for type-II kerogen between organic reactions predominantly involving H_2O and CO_2 elimination and those involving hydrocarbon generation (Comer, 1992, p. 76, fig. 2).

In the following estimations it is assumed that the amount of hydrogen available for hydrocarbon generation is equivalent to the amount of organic hydrogen present at the onset of the main stage of oil generation. With this limitation, the volume of hydrocarbons evolved from a specific source is estimated using the mass balance of organic hydrogen (H_{org}) where:

$$\text{Total } H_{org} = \text{Kerogen } H_{org} + \text{Hydrocarbon } H_{org} \quad (1)$$

$$\text{Hydrocarbon } H_{org} = \text{Immature } H_{org} - \text{Present } H_{org} \quad (2)$$

$$\text{Hydrocarbon } H_{org} = \text{In-Place Oil/Gas } H_{org} + \text{Expelled Oil/Gas } H_{org} \quad (3)$$

The key steps in the resource calculations are shown below. First, the essential data must be assembled for each potential reservoir. These include the reservoir area, average thickness, mean organic carbon concentration, mean organic hydrogen concentration, and bulk density. The calculations are accomplished as follows.

$$\text{Reservoir Mass (MT)} = \text{Thickness (km)} \times \text{Area (km}^2) \times \text{Density (MT/km}^3) \quad (4)$$

$$H_{org} \text{ Mass (MT)} = \text{Reservoir Mass (MT)} \times H_{org} \text{ (wt fraction)} \quad (5)$$

$$\text{Oil Volume (bbl)} = \text{Hydrocarbon } H_{org} \text{ (MT)} / 2.0 \times 10^{-2} \text{ (MT/bbl)} \quad (6)$$

$$\text{Gas Volume (ft}^3) = \text{Oil Volume (bbl)} \times 3{,}000 \text{ (ft}^3\text{/bbl)} \quad (7)$$

$$\text{Estimated Oil-In-Place (bbl)} = \text{Oil Volume (bbl)} \times (1 - \text{wt fraction of Oil Expelled}) \quad (8)$$

$$\text{Estimated Gas-In-Place (ft}^3) = \text{Gas Volume (ft}^3) \times (1 - \text{wt fraction of Gas Expelled}) \quad (9)$$

Units are metric tons (MT), kilometers (km), weight fraction (wt fraction), barrels (bbl), and cubic feet (ft^3). The conversions for the mass of hydrogen in a barrel of crude oil (2.0×10^{-2} MT/bbl) and for the volume of gas produced by the thermal cracking of 1 barrel of crude oil (3,000 ft^3/bbl) are taken from Barker (1990). A value of 30% (Comer and Hinch, 1987) is used as the efficiency of expulsion of oil from Woodford Shale in equation 8 and a value of 80% is used as the efficiency of expulsion of gas in equation 9.

Table 1 gives the reservoir thickness, area, volume, and mass for those regions with significant production potential. Reservoir mass was calculated using the mean density of 2.4 g/cc (2.4×10^9 MT/km^3) for Woodford Shale (Comer and Hinch, 1987).

The total mass of hydrogen contained in the hydrocarbons generated during thermal maturation is estimated using equations 2 and 5. The value for immature H_{org} used in this study was taken from the analyses of

TABLE 2.—Data from the Organic Fraction Used in This Assessment

Area name	Present C_{org} (%)	Immature C_{org} (%)	Present H_{org} (%)	Immature H_{org} (%)	Present R_o (%)	Immature R_o (%)
Anadarko Basin						
Probable success	82.0	82.2	7.72	7.74	0.55	0.39
Possible success	90.5	82.2	4.38	7.74	2.02	0.39
Local success	83.5	82.2	7.10	7.74	0.65	0.39
Permian Basin						
Probable success	82.0	82.2	7.72	7.74	0.55	0.39
Possible success	90.5	82.2	4.38	7.74	2.02	0.39
Local success	85.6	82.2	6.08	7.74	1.09	0.39

Note: Analyses were performed on the kerogen separated from samples of Woodford Shale core.

isolated, solvent extracted kerogen in the two Woodford Shale cores with lowest thermal maturity; these cores were recovered from the Jones & Pellow #1 Boyd and the Gulf #1 Schroeder wells located in Oklahoma County, Oklahoma (Comer, 1992, tables 1 and 2, cores A4 and A27). Average values from these two cores of 7.7 wt % hydrogen, 82 wt % carbon, and 0.39% R_o were applied to all of the regional resource calculations (Table 2). Because no kerogen data are available for Woodford Shale samples from the Permian Basin, data from the Anadarko Basin are used for the analogous facies (Table 2). This approach is reasonable because amorphous, type-II marine kerogen is the predominant organic matter type in Woodford Shale throughout the region (Comer, 1991, 1992). Kerogen data (Table 2) are converted to whole rock data (Table 3) by recognizing that the ratio of C_{org} to H_{org} in kerogen is the same as the ratio of C_{org} to H_{org} in whole rock using the relationship

$$(C_{org}/H_{org})_{kerogen} = (C_{org}/H_{org})_{whole\ rock} \qquad (10)$$

TABLE 3.—Whole Rock Data Used in This Assessment

Area name	Present C_{org} (%)	Immature C_{org} (%)	Present H_{org} (%)	Immature H_{org} (%)
Anadarko Basin				
Probable success	7.3	7.8	0.69	0.73
Possible success	4.2	5.8	0.20	0.55
Local success	5.4	5.6	0.46	0.53
Permian Basin				
Probable success	7.8	8.0	0.73	0.75
Possible success	4.2	5.8	0.20	0.55
Local success	3.6	4.0	0.26	0.38

Values for immature C_{org} in Table 3 are derived from the mean organic carbon concentration observed in each region adjusted using the mean organic carbon concentration in the two immature cores, the difference between the immature and observed level of thermal maturity, and the degree of dilution by clastic sediment.

The distribution of hydrogen mass for the prospective areas shown in Figure 4 is given in Table 4. The total mass of organic hydrogen is calculated using equation 5 and the data from Tables 1 and 3. For the area of probable success in the Anadarko Basin region, the total reservoir mass of 3.1×10^{12} MT (Table 1) multiplied by the mean H_{org} weight fraction for immature kerogen of 0.0073 (Table 3) gives the total initial H_{org} mass of 23×10^9 MT (Table 4). Similarly for the same area, the total reservoir mass of 3.1×10^{12} MT multiplied by the present H_{org} weight fraction for Woodford kerogen of 0.0069 (Table 3) gives the total residual H_{org} mass of 21×10^9

TABLE 4.—Distribution of Hydrogen Mass Estimated for Woodford Shale

Area name	Initial H_{org} MT x 10^9	Residual H_{org} MT x 10^9	Hydrocarbon H_{org} MT x 10^9
Anadarko Basin			
Probable success	23	21	2.0
Possible success	45	16	29
Local success	11	9.2	1.8
Permian Basin			
Probable success	11	10	1.0
Possible success	17	6.2	11
Local success	8.4	5.7	2.7

Note: Values are rounded to two significant figures.

TABLE 5.—Initial C_{org}, Natural Gas, and Hydrogen Mass Distribution for Woodford Shale

Area name	C_{org} MT x 10^9	Gas MT x 10^9	H_{gas} MT x 10^9	H_{oil} MT x 10^9
Anadarko Basin				
Probable success	240	0.024	0.0060	2.0
Possible success	480	60	21	8.4
Local success	110	0.44	0.11	1.7
Permian Basin				
Probable success	110	0.011	0.0028	1.0
Possible success	180	22	7.6	3.4
Local success	88	0.88	0.22	2.5

Note: Values are rounded to two significant figures.

MT (Table 4). The total mass of H_{org} in the hydrocarbons generated during thermal maturation (Table 4) is the difference between the initial (immature) and residual (present) H_{org} mass (equation 2).

The amount of natural gas co-generated along with oil during thermal maturation of low to moderate maturity marine black shale is estimated based on data from the literature (Table 5). For thermal maturities between 0.4 and 0.9% R_0, the saturated light hydrocarbon content increases more than two orders of magnitude mostly in the range from 1×10^5 ng/g C_{org} (1×10^{-4} MT/MT C_{org}) to 1×10^7 ng/g C_{org} (1×10^{-2} MT/MT C_{org}) (Schaefer and Leythaeuser, 1983). For those regions where Woodford Shale is in the oil window, the total mass of natural gas is estimated using the initial mass of C_{org} in immature shale (Table 3) and the published ratios where

$$\text{Gas (MT)} = \text{Gas (MT/MT } C_{org}) \times C_{org} \text{ (MT)} \quad (11)$$

For the region of probable success in Oklahoma (Fig. 4A), the initial C_{org} mass of 240×10^9 MT (Table 5) is equal to the reservoir mass of 3.1×10^{12} MT (Table 1) times the mean C_{org} weight fraction of 0.078 in immature shale (Table 3). In this region the mean vitrinite reflectance of Woodford Shale is 0.55% R_0 (Table 2) and, by analogy with Mesozoic marine black shale (Schaefer and Leythaeuser, 1983), the gas concentration is on the order of 1×10^{-4} MT/MT C_{org}. Hence, from equation 11, an initial C_{org} mass of 240×10^9 MT that generates gas at the concentration of 1×10^{-4} MT/MT C_{org} contains a total of 0.024×10^9 MT of natural gas (Table 5). Gas concentrations of 4×10^6 ng/g C_{org} (4×10^{-3} MT/MT C_{org}) and 1×10^7 ng/g C_{org} (1×10^{-2} MT/MT C_{org}) (Schaefer and Leythaeuser, 1983) are used in equation 11 for the areas of local success in the Anadarko and Permian Basin regions where the mean vitrinite reflectance is 0.65 and 1.09% R_0 (Table 2), respectively. The total mass of organic hydrogen that exists as natural gas (H_{gas}) is calculated by multiplying the resulting mass of gas by the weight fraction of H_{org} in gas where

$$H_{gas} \text{ (MT)} = \text{Gas (MT)} \times H_{org} \text{ (wt fraction)} \quad (12)$$

For the region of probable success in Oklahoma, the H_{gas} value of 0.0060×10^9 MT (Table 5) derives from multiplying the total of 0.024×10^9 MT of natural gas times the weight fraction of hydrogen in gas (0.25 for methane). The gas volume of 1.2×10^{12} ft^3 (Table 6) is calculated by dividing the total mass of organic hydrogen in gas (0.0060×10^9 MT) by the mass of hydrogen in a cubic foot of natural gas (5×10^{-6} MT/ft^3) (Barker, 1990). The mass of hydrogen contained in crude oil (H_{oil}) shown in Table 5 is the difference between the total mass of H_{org} in hydrocarbons (Table 4) and the mass of hydrogen in gas (H_{gas}) (Table 5).

For those regions where the Woodford Shale is in the gas window, it is assumed that all of the indigenous oil has cracked to gas. For the area of possible success in the Anadarko Basin region where the mean R_0 is 2%

TABLE 6.—Estimated Volumes of Generated, Expelled, and In-Place Oil and Gas for Woodford Shale

	Generated		Expelled		In-Place	
Area name	Oil bbl x 10^9	Gas ft^3 x 10^{12}	Oil bbl x 10^9	Gas ft^3 x 10^{12}	Oil bbl x 10^9	Gas ft^3 x 10^{12}
Anadarko Basin						
Probable success	100	1.2	30	0.96	70	0.24
Possible success	1,400	3,000	420	2,400	0.0	600
Local success	85	22	25	18	60	4.4
Permian Basin						
Probable success	50	0.55	15	0.44	35	0.11
Possible success	550	1,100	170	880	0.0	220
Local success	120	43	36	34	84	9.0

Note: For the corresponding map areas, see Figure 4.
Values are rounded to two significant figures.

(Table 2), the total hydrocarbon H_{org} mass of 29×10^9 MT (Table 4) divided by 2.0×10^{-2} MT/bbl (equation 6) gives the total amount of oil generated of $1{,}400 \times 10^9$ bbl (Table 6). If 30% of this oil (420×10^9 bbl) was expelled, then 8.4×10^9 MT of hydrogen (420×10^9 bbl times 2×10^{-2} MT/bbl) was removed from the Woodford in the oil phase (equation 6). The value for H_{gas} of 21×10^9 MT (Table 5) is the difference between the total hydrocarbon H_{org} of 29×10^9 MT (Table 4) and the H_{oil} of 8.4×10^9 MT (Table 5). The volume of natural gas is calculated using equations 6 and 7 where the mass of hydrogen retained in the Woodford of 21×10^9 MT represents $1{,}000 \times 10^9$ bbl of crude oil that cracked to $3{,}000 \times 10^{12}$ ft^3 of natural gas (Table 6). Expulsion of 80% of this gas would leave 600×10^{12} ft^3 in place (Table 6). The mass of natural gas of 60×10^9 MT (Table 5) results from dividing the gas volume ($3{,}000 \times 10^{12}$ ft^3) (Table 6) by the volume occupied by a metric ton of natural gas (5.0×10^4 ft^3/MT) (Barker, 1990).

For those regions where the Woodford Shale is in the oil window, total generated oil is calculated using equation 6. For the area of probable success in the Anadarko Basin region where the mean vitrinite reflectance is 0.55% R_o (Table 2), the mass of hydrogen in oil (H_{oil}) of 2.0×10^9 MT (Table 5) converts to 100×10^9 bbl (Table 6). Expulsion of 30% of the oil (30×10^9 bbl) would leave 70×10^9 bbl in place (Table 6).

This assessment suggests that the total in-place gas resources in Woodford Shale are on the order of 830×10^{12} ft^3 and the total in-place oil resources are on the order of 250×10^9 bbl in those regions of the southern Midcontinent evaluated in this study (Table 6). These volumes include 600×10^{12} ft^3 of gas-in-place and 130×10^9 bbl of oil-in-place in the Anadarko Basin region, and 230×10^{12} ft^3 of gas-in-place and 120×10^9 bbl of oil-in-place in the Permian Basin region. The Anadarko Basin region contains significantly more gas-in-place primarily because of the much greater area where Woodford Shale is deeply buried and in the gas generation window.

CONCLUSIONS

The Woodford Shale is a major unconventional energy resource with the potential for producing significant volumes of both oil and gas. Intuitively, its status as a world-class oil source rock indicates that the formation would contain large residual concentrations of hydrocarbons, and analytical data from numerous studies confirm this inference. The inherent inefficiency of oil expulsion is the primary reason why oil-prone source rocks like the Woodford retain large volumes of hydrocarbons and are attractive targets for unconventional oil and gas exploration.

Creating a regional exploration model for this unconventional resource requires a basic understanding of both reservoir and source rock properties. Stratigraphic analysis provided the depositional model that allowed lithologic associations, facies distribution, and reservoir properties to be understood and predicted, and organic analysis contributed data on the spatial distribution and levels of organic carbon, organic hydrogen, and thermal maturity that allowed volumes of oil-in-place and gas-in-place to be estimated. Optimum locations for exploration are where organic-rich beds are currently in the oil or gas generation window and are highly fractured. Optimum reservoir facies are those comprising brittle lithologies capable of maintaining open natural fracture networks such as chert, siltstone, sandstone, and dolostone. In the southern Midcontinent, these self-sourcing reservoir conditions coincide where organic-rich, thermally mature beds of brittle lithology lie along fracture trends in orogenic belts, rift basins, and associated uplifts. The most promising exploration targets include intervals with chert, sandstone, and dolostone on the Nemaha Uplift in Oklahoma; sections of interbedded chert and black shale in the Marietta-Ardmore Basin, Arbuckle Mountain Uplift, southern flank of the Anadarko Basin, and frontal zone of the Ouachita Tectonic Belt in Oklahoma; and intervals of chert and siltstone on the Central Basin Platform and Pecos Arch in Texas and New Mexico.

The volumes of oil-in-place and gas-in-place estimated for Woodford Shale in the southern Midcontinent are substantial. The total unconventional energy resource potential is estimated to be 830×10^{12} ft^3 of natural gas and 250×10^9 bbl of crude oil. The oil potential is 70×10^9 bbl in the area of probable success in the Anadarko Basin region (Fig. 4A), an area that encompasses the Nemaha Uplift, Marietta-Ardmore Basin, Arbuckle Mountain Uplift, southern flank of the Anadarko Basin, and frontal zone of the Ouachita Tectonic Belt in Oklahoma. In this same area Woodford Shale is estimated to contain 0.24×10^{12} ft^3 of gas-in-place. Approximately 140×10^9 bbl of oil-in-place, 84×10^9 bbl in the Permian Basin region and 60×10^9 bbl in the Anadarko Basin region, is estimated for the areas of local success that encompass much of the shelf and platform provinces and most of the Midland Basin (Fig. 4). In these same areas Woodford Shale contains an estimated 13×10^{12} ft^3 of gas-in-place, approximately 9×10^{12} ft^3 in the Permian Basin region and 4.4×10^{12} ft^3 in the Anadarko Basin region. Significantly more in-place gas and oil is estimated for areas of local success in the Permian Basin region primarily because the thermal maturity is much higher (Table 2). The area of probable success in the Permian Basin region, an area that encompasses the Central Basin Platform and the Pecos Arch, is estimated to contain 35×10^9 bbl of oil-in-place and 0.11×10^{12} ft^3 of gas-in-place. The greatest gas potential is 600×10^{12} ft^3 in the area of possible success in the Anadarko Basin region (Fig. 4A), an area that includes the deepest parts of the Anadarko and Arkoma Basins. The area of possible success in the Permian Basin region, an area that includes the deep parts of the Delaware and Val Verde Basins, is estimated to contain 220×10^{12} ft^3 of gas-in-place.

Although estimates of the volume of undiscovered hydrocarbons are inherently problematic because of the assumptions that must be made in order to complete the calculations, mass balance estimates offer reasonable orders-of-magnitude for in-place oil and gas and provide a consistent means to compare and rank different areas of interest as to their hydrocarbon production potential.

Although the in-place volumes are huge, technological challenges must be overcome to achieve commercial production. However, given the magnitude of estimates, the local production from fractured reservoirs, recent successes in unconventional resource recovery from analogous formations, and current oil and gas prices, Woodford Shale in the southern Midcontinent is a compelling exploration target.

ACKNOWLEDGMENTS

This report is dedicated to the memory of Henry H. Hinch who contributed considerable time and energy to collecting the samples and interpreting the data represented in this work and in the key supporting publications (Comer and Hinch, 1987; Comer, 1992). Henry's friendship, good humor, curiosity, and scientific acumen stimulated my research on the Woodford Shale and provided inspiration from the conception through the analysis to the publication of this and related work. Any time I study the Woodford, nostalgic recollections of the field and laboratory work we shared inevitably arise. Henry's many contributions are gratefully acknowledged and his collegial energy is sorely missed.

The manuscript was reviewed at the Indiana Geological Survey by Brian D. Keith, Nancy R. Hasenmueller, Margaret V. Ennis, and Wilfrido Solano and at the U. S. Geological Survey by Michael D. Lewan. At the Indiana Geological Survey, Amy E. Foster formatted the text and tables, Kimberly H. Sowder, under the supervision of Richard T. Hill, drafted the figures, and Deborah A. DeChurch edited the revised manuscript. Publication is authorized by John C. Steinmetz, State Geologist and Director of the Indiana Geological Survey.

REFERENCES CITED

Amsden, T. W., 1975, Hunton Group (Late Ordovician, Silurian, and Early Devonian) in the Anadarko Basin of Oklahoma: Oklahoma Geological Survey Bulletin 121, 214 p.

_____1980, Hunton Group (Late Ordovician, Silurian and Early Devonian) in the Arkoma Basin of Oklahoma: Oklahoma Geological Survey Bulletin 129, 136 p.

Amsden, T. W.; and Klapper, G., 1972, Misener sandstone (Middle–Upper Devonian), north-central Oklahoma: American Association of Petroleum Geologists Bulletin, v. 56, p. 2323–2334.

Amsden, T. W.; Caplan, W. M.; Hilpman, P. L.; McGlasson, E. H.; Rowland, T. L.; and Wise, O. A., 1967, Devonian of the southern Midcontinent area, United States, *in* Oswald, D. H. (ed.), International symposium on the Devonian System, v. 1: Alberta Society of Petroleum Geologists, Calgary, Canada, p. 913–932.

Barker, C., 1990, Calculated volume and pressure changes during the thermal cracking of oil to gas in reservoirs: American Association of Petroleum Geologists Bulletin, v. 74, p. 1254–1261.

Brenneman, M. C.; and Smith, P. V., 1958, The chemical relationships between crude oils and their source rocks, *in* Weeks, L. G. (ed.), Habitat of oil: American Association of Petroleum Geologists, Tulsa, Oklahoma, p. 818–849.

Burruss, R. C.; and Hatch, J. R., 1989, Geochemistry of oils and hydrocarbon source rocks, greater Anadarko Basin: evidence for multiple sources of oils and long-distance oil migration, *in* Johnson, K. S. (ed.), Anadarko Basin symposium, 1988: Oklahoma Geological Survey Circular 90, p. 53–64.

Cardott, B. J., 1989, Thermal maturation of the Woodford Shale in the Anadarko Basin, *in* Johnson, K. S. (ed.), Anadarko Basin symposium, 1988: Oklahoma Geological Survey Circular 90, p. 32–46.

_____2005, Overview of unconventional energy resources of Oklahoma, *in* Cardott, B. J. (ed.), Unconventional energy resources in the southern Midcontinent, 2004 symposium: Oklahoma Geological Survey Circular 110 [this volume], p. 7–18.

Cardott, B. J.; and Lambert, M. W., 1985, Thermal maturation by vitrinite reflectance of Woodford Shale, Anadarko Basin, Oklahoma: American Association of Petroleum Geologists Bulletin, v. 69, p. 1982–1998.

Carr, J. L., 1987, The thermal maturity of the Chattanooga Formation along a transect from the Ozark Uplift to the Arkoma Basin: Shale Shaker, v. 38, p. 32–40.

Cloud, P. E.; Barnes, V. E.; and Hass, W. H., 1957, Devonian–Mississippian transition in central Texas: Geological Society of America Bulletin, v. 68, p. 807–816.

Comer, J. B., 1991, Stratigraphic analysis of the Upper Devonian Woodford Formation, Permian Basin, West Texas and southeastern New Mexico: Bureau of Economic Geology, Austin, Texas, Report of Investigations 201, 63 p.

_____1992, Organic geochemistry and paleogeography of Upper Devonian formations in Oklahoma and northwestern Arkansas, *in* Johnson, K. S.; and Cardott, B. J. (eds.), Source rocks in the southern Midcontinent, 1990 symposium: Oklahoma Geological Survey Circular 93, p. 70–93.

Comer, J. B.; and Hinch, H. H., 1987, Recognizing and quantifying expulsion of oil from the Woodford Formation and age-equivalent rocks in Oklahoma and Arkansas: American Association of Petroleum Geologists Bulletin, v. 71, p. 844–858.

Curiale, J. A., 1983, Petroleum occurrences and source rock potential of the Ouachita Mountains, southeastern Oklahoma: Oklahoma Geological Survey Bulletin 135, 65 p.

Freeman, T.; and Schumacher, D., 1969, Qualitative pre-Sylamore (Devonian–Mississippian) physiography delineated by onlapping conodont zones, northern Arkansas: Geological Society of America Bulletin, v. 80, p. 2327–2334.

Galley, J. E., 1958, Oil and geology in the Permian Basin of Texas and New Mexico, *in* Weeks, L. G. (ed.), Habitat of oil: American Association of Petroleum Geologists, Tulsa, Oklahoma, p. 395–446.

Graves, R. W., 1952, Devonian conodonts from the Caballos Novaculite: Journal of Paleontology, v. 26, p. 610–612.

Ham, W. E., 1969, Regional geology, *part I of* Regional geology of the Arbuckle Mountains, Oklahoma: Oklahoma Geological Survey Guidebook 17, p. 5–21.

Ham, W. E.; and Wilson, J. L., 1967, Paleozoic epeirogeny and orogeny in the central United States: American Journal of Science, v. 265, p. 332–407.

Harlton, B. H., 1956, The Harrisburg trough, Stevens and Carter Counties, Oklahoma, *in* Hicks, I. C.; Westheimer, J.; Thomlinson, C. W.; Putman, D. M.; and Seik, E. L. (eds.), Petroleum geology of southern Oklahoma, v. 1: American Association of Petroleum Geologists, Tulsa, Oklahoma, p. 135–143.

Hass, W. H.; and Huddle, J. W., 1965, Late Devonian and Early Mississippian age of the Woodford Shale in Oklahoma, as determined from conodonts: U. S. Geological Survey Professional Paper 525-D, p. D125–D132.

Heckel, P. H.; and Witzke, B. J., 1979, Devonian world palaeogeography determined from distribution of carbonates and related lithic palaeoclimatic indicators: Special Papers in Palaeontology, v. 23, p. 99–123.

Houseknecht, D. W.; and Matthews, S. M., 1985, Thermal maturity of Carboniferous strata, Ouachita Mountains: American Association of Petroleum Geologists Bulletin, v. 69, p. 335–345.

Houseknecht, D. W.; Haton, L. A.; and McGilvery, T. A., 1992, Thermal maturity of Paleozoic strata in the Arkoma Basin, *in* Johnson, K. S.; and Cardott, B. J. (eds.), Source rocks in the southern Midcontinent, 1990 symposium: Oklahoma Geological Survey Circular 93, p. 122–132.

Huffman, G. G., 1958, Geology of the flanks of the Ozark uplift: Oklahoma Geological Survey Bulletin 77, 281 p.

Hunt, J. M., 1961, Distribution of hydrocarbons in sedimentary rocks: Geochimica et Cosmochimica Acta, v. 22, p. 37–49.

_____1996, Petroleum geochemistry and geology [2nd edition]: W. H. Freeman and Co., New York City, 743 p.

Iztan, Y. H., 1985, Geochemical correlation between crude oils from Misener reservoirs and potential source rocks in central and north-central Oklahoma: University of Tulsa unpublished M.S. thesis, 191 p.

Jones, P. J.; and Philp, R. P., 1990, Oils and source rocks from Pauls Valley, Anadarko Basin, Oklahoma, U.S.A.: Applied Geochemistry, v. 5, p. 429–448.

King, P. B.; King, R. E.; and Knight, J. B., 1945, Geology of the Hueco Mountains, El Paso and Hudspeth Counties, Texas: U.S. Geological Survey, Oil and Gas Investigations Preliminary Map 36.

Landis, C. R.; Trabelsi, A.; and Strathearn, G., 1992, Hydrocarbon potential of selected Permian Basin shales as classified within the organic facies concept, *in* Johnson, K. S.; and Cardott, B. J. (eds.), Source rocks in the southern Midcontinent, 1990 symposium: Oklahoma Geological Survey Circular 93, p. 229–247.

Laudon, L. R.; and Bowsher, A. L., 1949, Mississippian formations of southwestern New Mexico: Geological Society of America Bulletin, v. 60, p. 1–88.

Lewan, M. D., 1997, Experiments on the role of water in petroleum formation: Geochimica et Cosmochimica Acta, v. 61, p. 3691–3723.

Lewan, M. D.; Winters, J. C.; and McDonald, J. H., 1979, Generation of oil-like pyrolyzates from organic-rich shales: Science, v. 203, p. 897–899.

Lowe, D. R., 1975, Regional controls on silica sedimentation in the Ouachita system: Geological Society of America Bulletin, v. 86, p. 1123–1127.

Park, D. E.; and Croneis, C., 1969, Origin of Caballos and Arkansas Novaculite formations: American Association of Petroleum Geologists Bulletin, v. 53, p. 94–111.

Parrish, J. T., 1982, Upwelling and petroleum source beds, with reference to Paleozoic: American Association of Petroleum Geologists Bulletin, v. 66, p. 750–774.

Philp, R. P.; Jones, P. J.; Lin, L. H.; Michael, G. E.; and Lewis, C. A., 1989, An organic geochemical study of oils, source rocks, and tar sands in the Ardmore and Anadarko Basins, *in* Johnson, K. S. (ed.), Anadarko Basin symposium, 1988: Oklahoma Geological Survey Circular 90, p. 65–76.

Poole, F. G., 1974, Flysch deposits of Antler foreland basin, western United States, *in* Dickinson, W. R. (ed.), Tectonics and sedimentation: Society of Economic Paleontologists and Mineralogists Special Publication No. 22, p. 58–82.

Poole, F. G.; Baars, D. L.; Drewes, H.; Hayes, P. T.; Ketner, K. B.; McKee, E. D.; Teichert, C.; and Williams, J. S., 1967, Devonian of the southwestern United States, *in* Oswald, D. H. (ed.), International symposium on the Devonian System, v. 1: Alberta Society of Petroleum Geologists, Calgary, Canada, p. 879–912.

Reber, J. J., 1988, Correlation and biomarker characterization of Woodford-type oil and source rock, Aylesworth Field, Marshall County, Oklahoma: University of Tulsa unpublished M.S. thesis, 96 p.

Schaefer, R. G.; and Leythaeuser, D., 1983, Generation and migration of low-molecular weight hydrocarbons in sediments from Site 511 of DSDP/IOPD Leg 71, Falkland Plateau, South Atlantic, *in* Bjoroy, M. (ed.), Advances in organic geochemistry 1981: John Wiley, Chichester, United Kingdom, p. 164–174.

Schimmelmann, A.; Lewan, M. D.; and Wintsch, R. P., 1999, D/H isotope ratios of kerogen, bitumen, oil, and water in hydrous pyrolysis of source rocks containing kerogen types I, II, IIS, and III: Geochimica et Cosmochimica Acta, v. 63, p. 3751–3766.

Stevenson, F. V., 1945, Devonian of New Mexico: Journal of Geology, v. 53, p. 217–245.

Sullivan, K. L., 1985, Organic facies variation of the Woodford Shale in western Oklahoma: Shale Shaker, v. 35, p. 76–89.

Tissot, B. P.; and Welte, D. H., 1984, Petroleum formation and occurrence [2nd edition]: Springer-Verlag, New York City, 699 p.

Wang, H. D.; and Philp, R. P., 1997, Geochemical study of potential source rocks and crude oils in the Anadarko Basin, Oklahoma: American Association of Petroleum Geologists Bulletin, v. 81, p. 249–275.

Welte, D. H.; Hagemann, H. W.; Hollerbach, A.; Leythaeuser, D.; and Stahl, W., 1975, Correlation between petroleum and source rock: Proceedings of the Ninth World Petroleum Congress, v. 2, p. 179–191.

Winters, J. C.; Williams, J. A.; and Lewan, M. D., 1983, A laboratory study of petroleum generation by hydrous pyrolysis, *in* Bjoroy, M.; Albrecht, P.; Cornford, C.; deGroot, K.; Eglinton, G.; Galimov, E.; Leythaeuser, D.; Pelet, R.; Rullkotter, J.; and Speers, G. (eds.), Advances in organic geochemistry 1981: John Wiley, Chichester, United Kingdom, p. 524–533.

Coalbed-Methane Development in Kansas

Timothy R. Carr, K. David Newell, Troy A. Johnson, W. Matthew Brown, and Jonathan P. Lange
Kansas Geological Survey
Lawrence, Kansas

ABSTRACT.—In eastern Kansas, coals and organic shales in the Middle Pennsylvanian (Desmoinesian) Cherokee and Marmaton Groups are increasingly important commercial sources for unconventional gas (Fig. 1). Over the past 3 years, almost 1,500 wells have been drilled or recompleted for coalbed and organic-shale gas (Fig. 2). Although current production of approximately 10 billion cubic feet is a relatively small percentage of total Kansas production, coalbed-methane gas production is rapidly increasing. Current development and production is concentrated in southeastern Kansas (Labette, Montgomery, Neosho, and Wilson Counties), but exploration and production is expanding northward and westward, particularly along pipelines (Fig. 3).

Although individual coals are thin, numerous coals can be perforated and produced in an individual well. The distribution, thickness, and quality of individual coals vary both regionally and locally and is strongly influenced by depositional processes and paleotopography. As part of a regional study, Middle Pennsylvanian coals and organic shales were mapped in the subsurface, and a series of cores were obtained. Coal samples from cores and cuttings were analyzed for gas content and desorption rates, ash and sulfur contents, and other coal properties. Preliminary analysis shows gas content of individual coals generally decreases north–northeast along regional strike, and eastward where strata onlap onto the Ozark Dome. Gas content of the better coals at depth has a maximum of 250–300 standard cubic feet/ton (scf/ton) in southeast Kansas (Fig. 4). However, some shallow coals at less than 700 ft in depth have unexpectedly large gas contents (>100 scf/ton) exceeding that of deeper coals. To the north across the Bourbon Arch region, gas content of coals range from 50 to 175 scf/ton.

Understanding the stratigraphic, structural, and depositional setting of individual coal-bearing successions can aid development of a better understanding of the lateral variability of thickness, quality, and gas content, and better focus coalbed-methane exploration and development in eastern Kansas.

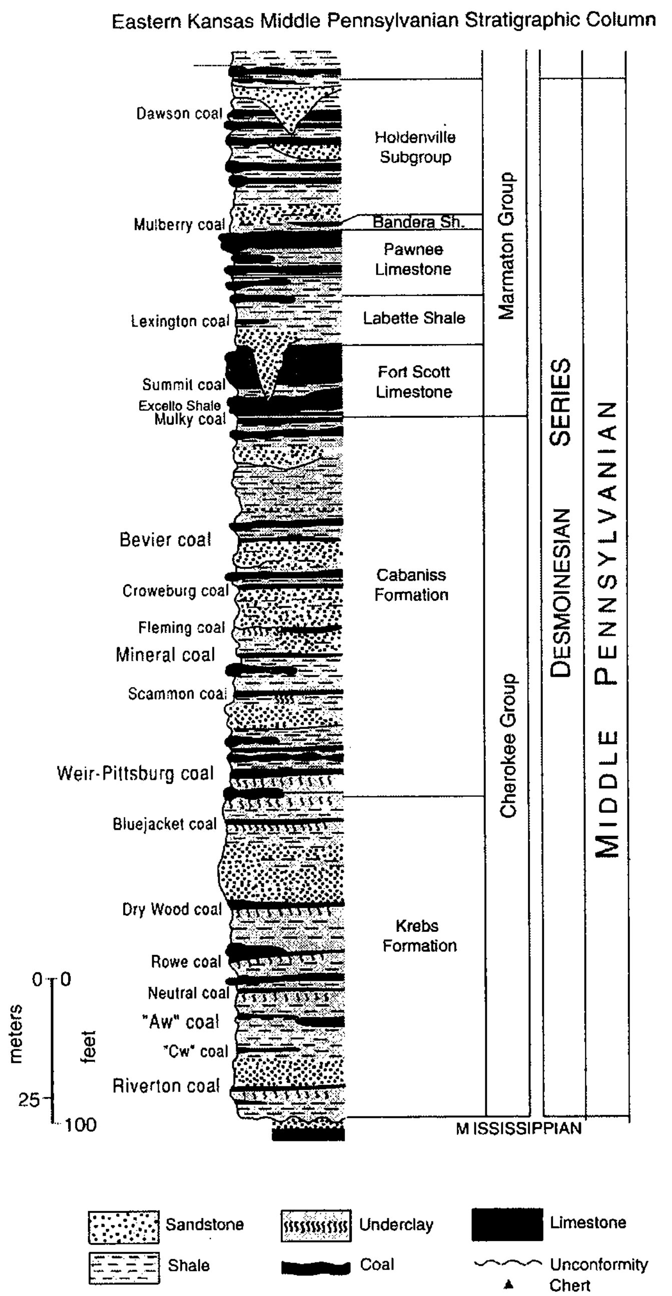


Figure 1. Stratigraphic classification of the Pennsylvanian (Desmoinesian Series) in Kansas showing major coals.

Carr, T. R.; Newell, K. D.; Johnson, T. A.; Brown, W. M.; and Lange, J. P., 2005, Coalbed-methane development in Kansas, *in* Cardott, B. J. (ed.), Unconventional energy resources in the southern Midcontinent, 2004 symposium: Oklahoma Geological Survey Circular 110, p. 63–65.

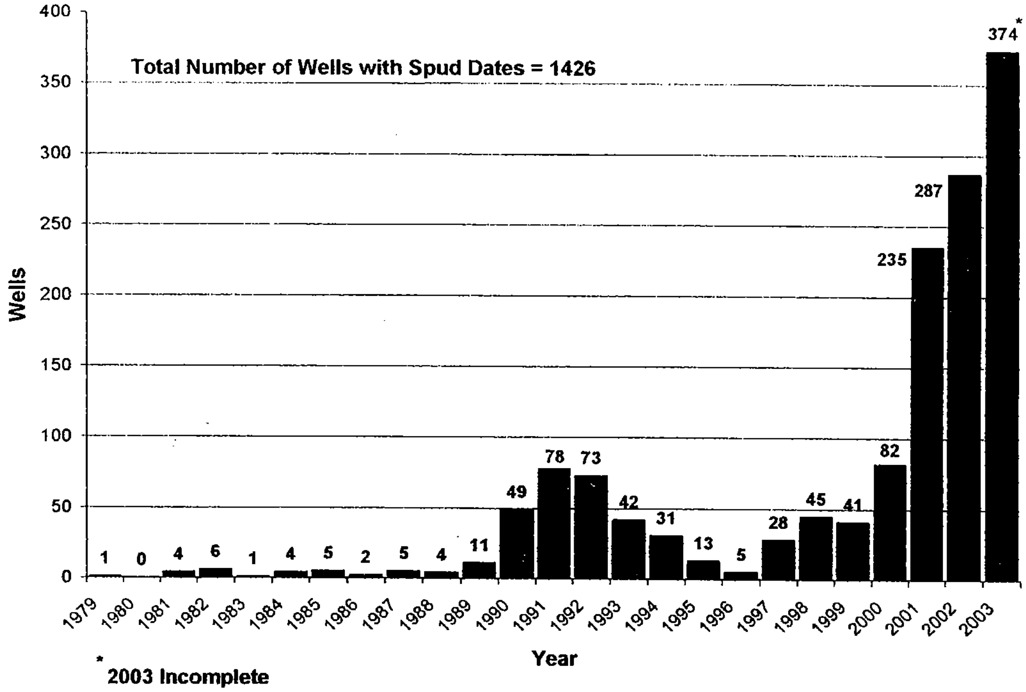


Figure 2. Completion activity in Kansas by year through 2003 for wells with coalbed-methane status.

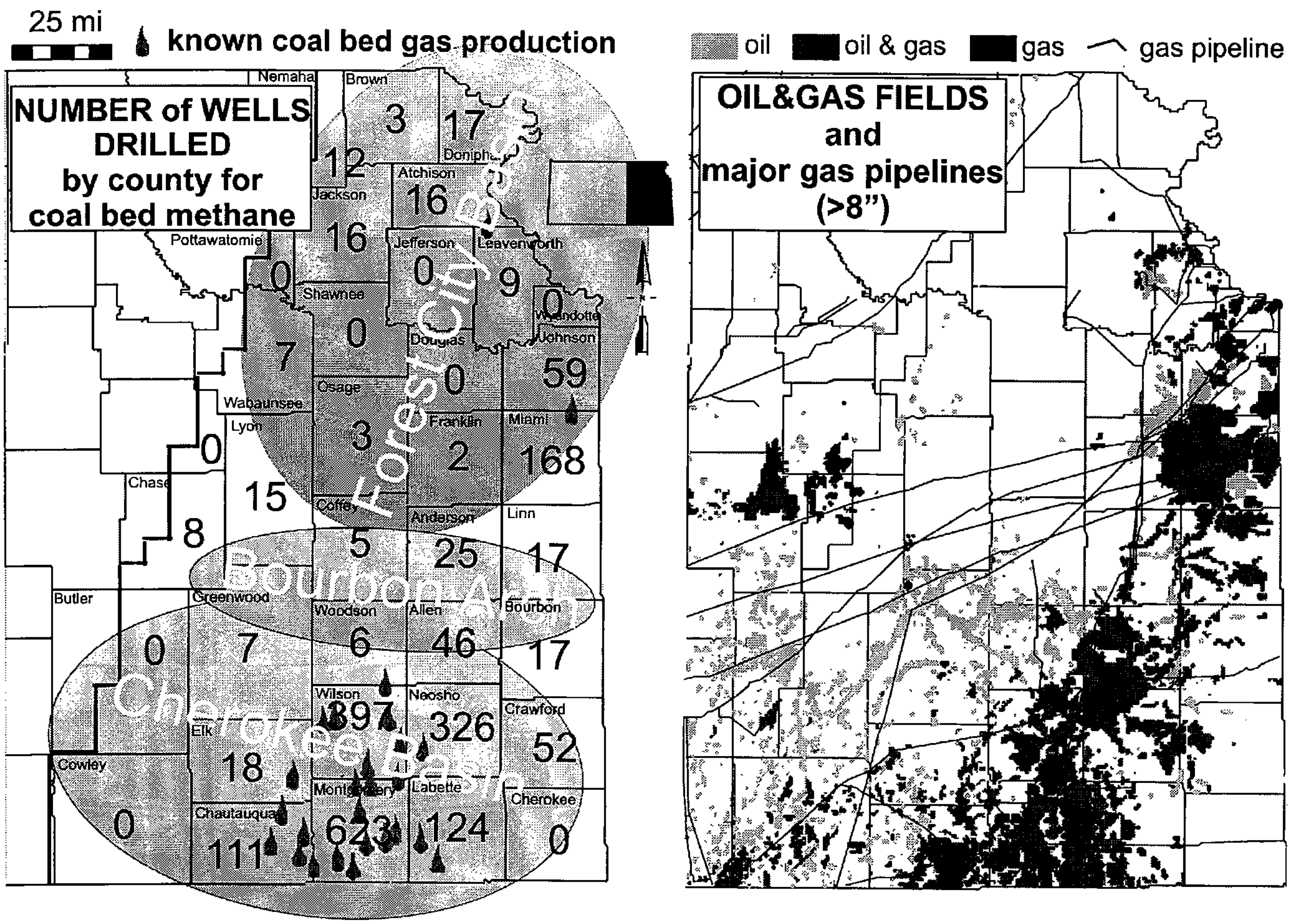


Figure 3. Map of eastern Kansas showing the distribution by county of coalbed-methane wells drilled between January 1999 and December 2003; and the same map showing the distribution of conventional petroleum reservoirs along with existing major pipeline infrastructure.

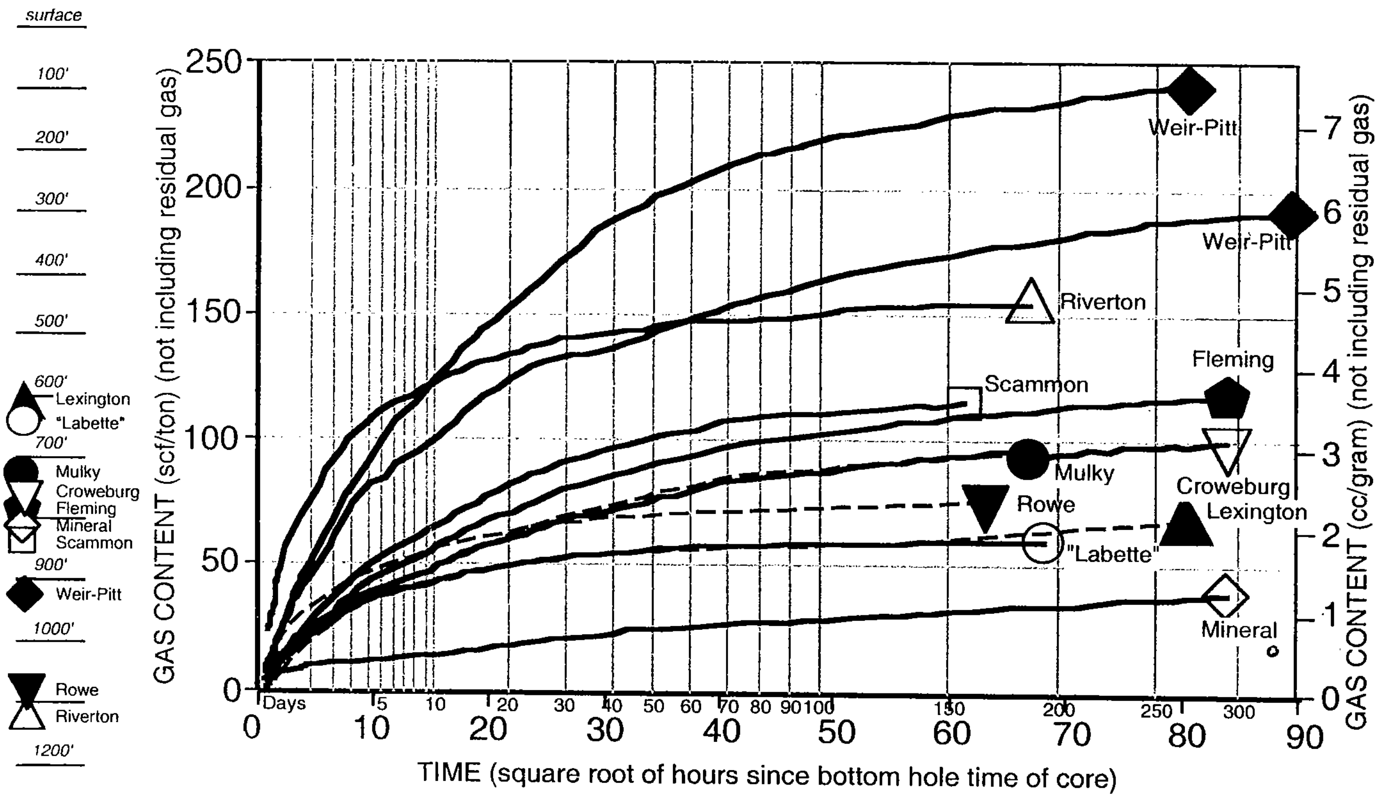


Figure 4. Typical desorption characteristics for coals sampled from a single well in Montgomery County, Kansas.

Natural Gas Potential of Arkansas Coals

William L. Prior
Arkansas Geological Commission
Little Rock, Arkansas

ABSTRACT.—The coal-bearing formations of Pennsylvanian age in the Arkoma Basin of western Arkansas are, in ascending order: Atoka, Hartshorne, McAlester, and Savanna. These coal-bearing units cover more than 1,700 mi^2. The coals range in rank from low-volatile bituminous coal in the western part of the basin to semi-anthracite (>86% fixed carbon) in the eastern portion of the coal basin. The total resource estimate is >2 billion short tons.

The general east–west folded and faulted structure of the Arkoma Basin is a major factor in the distribution and depth of the coal seams. There are some 25 coal seams in the sequence but only four coal beds have been mapped and named. They are, in ascending order: the Lower and Upper Hartshorne coals, both of which are in the lower part of the McAlester Formation, and the Charleston and Paris coals in the Savanna Formation.

The Lower Hartshorne coal is the thickest and most extensive of all the coal seams with a reported thickness of as much as 8 ft in southern Sebastian County and covers some 1,300 mi^2 within the basin. More than 30 coalbed-methane wells (as of 2004) have been drilled into the Lower Hartshorne coal near Hartford, Arkansas, and have produced >2 billion cubic feet (Bcf) of methane. These wells are both conventional vertical wells and horizontal pinnate wells. These wells range in depth from 400 to >2,000 ft.

A second coal-bearing region is present in southern and eastern Arkansas in the Gulf Coastal Plain. Ongoing projects carried out in other states of the western Gulf Coast seem to indicate that coals that are buried >1,500 ft may have a potential for producing methane. The Desha Basin in southeast Arkansas is the area in which coals within the Wilcox Group (Eocene) are >1,500 ft deep. Other possible coals in the Lower Cretaceous could exist at depths of 3,000–3,500 ft. The Desha Basin covers approximately 8,200 mi^2.

Prior, W. L., 2005, Natural gas potential of Arkansas coals, *in* Cardott, B. J. (ed.), Unconventional energy resources in the southern Midcontinent, 2004 symposium: Oklahoma Geological Survey Circular 110, p. 67.

Coalbed-Methane Activity in Oklahoma, 2004 Update

Brian J. Cardott
Oklahoma Geological Survey
Norman, Oklahoma

ABSTRACT.—Nearly 2,900 wells in the Oklahoma coalfield have been drilled exclusively for coalbed methane (CBM) since 1988, in part for the Federal Section 29 tax credit and in part due to higher prices for natural gas. A database of CBM completions tabulates 1,725 completions in the northeast Oklahoma shelf and 1,171 completions in the Arkoma Basin. Operators presently target 13 coal objectives in the shelf and five in the basin. The primary CBM objectives, all Desmoinesian (Middle Pennsylvanian), are the Mulky (547 wells) and Rowe (601 wells) coals in the shelf and the Hartshorne coals (1,125 wells) in the basin.

Coals in Arkoma Basin CBM wells are generally deeper and thicker than those in the northeast Oklahoma shelf and have higher initial gas rates and lower initial produced-water rates. Many horizontal CBM wells have been drilled in the Arkoma Basin since 1998, the more successful wells following improvements in completion techniques. Much is known about the coal geology of the Oklahoma coalfield (e.g., number of coals, age, depth, thickness, rank, quality). The present emphasis is on finding permeable sweet spots and matching coal characteristics to optimum completion techniques.

INTRODUCTION

Mine explosions from gas and dust caused more than 500 deaths in 19 major coal-mining disasters in the Indian Territory and Oklahoma from 1885 to 1945 (Oklahoma Department of Mines, 2003). Gas explosions in underground coal mines and safety studies of underground coal mines by the U.S. Bureau of Mines (Deul and Kim, 1988) demonstrated that Oklahoma coals contain large amounts of methane. Applied research by the U.S. Bureau of Mines, U.S. Department of Energy, and Oklahoma Geological Survey, advances in coalbed-methane (CBM) completion technology (especially through studies of coals in the Black Warrior and San Juan Basins by the Gas Research Institute), Federal non-conventional fuel tax credit (Section 29 of the IRS Code; see Sanderson and Berggren, 1998, for details), and high natural gas prices (>$3 per thousand cubic feet, Mcf, since 2000) all promoted interest in development of the Oklahoma CBM industry.

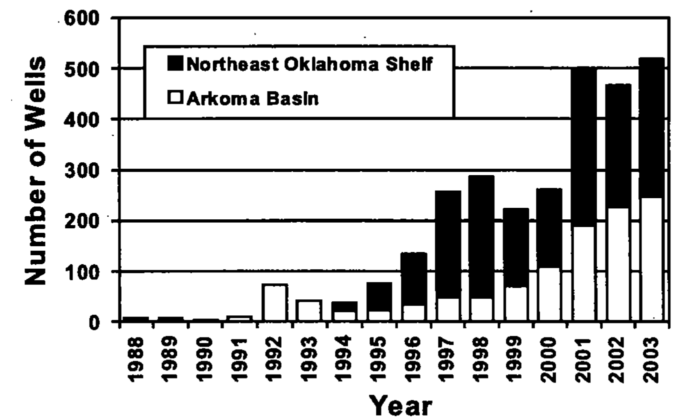


Figure 1. Histogram showing numbers of Oklahoma coalbed-methane (CBM) well completions, 1988–2003.

The CBM play in Oklahoma began in 1988 with the first completions in the Arkoma Basin (Figs. 1, 2). Bear Productions reported initial-potential (IP) gas rates of 41–45 thousand cubic feet of gas per day (Mcfd) per well from seven wells in the Hartshorne coal at depths ranging from 611 to 716 ft in the Kinta gas field (sec. 27, T. 8 N., R. 20 E., Indian Meridian) in Haskell County. Bear Productions was the only CBM operator in Oklahoma from 1988 to 1990. Following a peak of 73 completions in 1992 (at the end of the first phase of the Section 29 tax credit for new CBM wells drilled from 1980 through 1992), activity declined for several years before rising to 247 completions reported in the basin in 2003 (stimulated by high gas prices). CBM completions in the northeast Oklahoma shelf began in 1994 with 15 wells. Numerous CBM completions in the shelf were recompletions and were eligible for the second phase of the Section 29 tax credit (recompletion to qualifying coal beds in conventional wells drilled from 1980 through

Cardott, B. J., 2005, Coalbed-methane activity in Oklahoma, 2004 update, *in* Cardott, B. J. (ed.), Unconventional energy resources in the southern Midcontinent, 2004 symposium: Oklahoma Geological Survey Circular 110, p. 69–81.

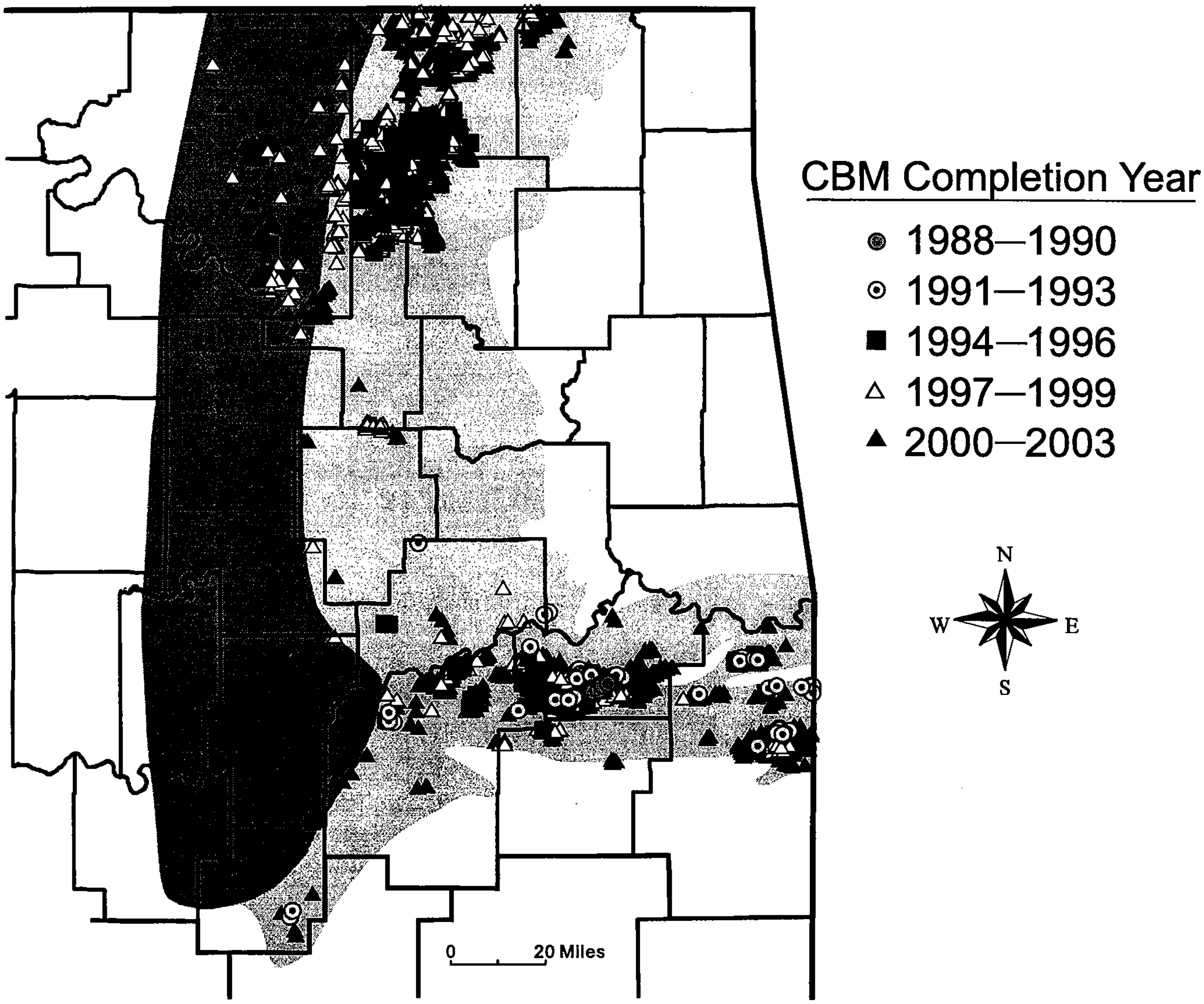


Figure 2. Map showing coalbed-methane (CBM) well completions in Oklahoma by year.

1992; gas must be produced and sold by December 31, 2002). Shelf completions totaled 235 and 304 in 1998 and 2001, respectively. More CBM wells per year have been drilled in the shelf than in the basin since 1995. Through December 2003, 2,896 CBM completions were reported in Oklahoma. Of these completions, 1,171 were in the Arkoma Basin and 1,725 in the northeast Oklahoma shelf.

The Oklahoma coalfield is in the eastern part of the State and occupies the southern part of the western region of the Interior Coal Province of the United States (Campbell, 1929; Friedman, 2002). The coalfield is divided into the northeast Oklahoma shelf and the Arkoma Basin (Friedman, 1974; Fig. 3). CBM completions are in both the commercial coal belt and noncommercial coal-bearing region. Cardott (2002) summarized the coal geology of Oklahoma. The remainder of this report will discuss the CBM activity of the northeast Oklahoma shelf and the Arkoma Basin.

SOURCES OF DATA

The following discussion of Oklahoma CBM activity is based on information reported to the Oklahoma Corporation Commission and Osage Indian Agency. The names of coal beds are as reported by the operator. For the most part, coal names assigned by operators were not verified with electric logs and may not conform to usage accepted by the Oklahoma Geological Survey (OGS). Because not all the wells are reported as CBM wells, some interpretation or verification with the operator was necessary. Dual completions in sandstone and coal beds, including perforations of more than one coal bed, were made in some wells. Therefore, not all the wells are exclusively CBM completions. Dual completions were included only if gas rates were reported for the coal beds.

This summary is incomplete inasmuch as some wells were not known to be CBM wells or were not reported

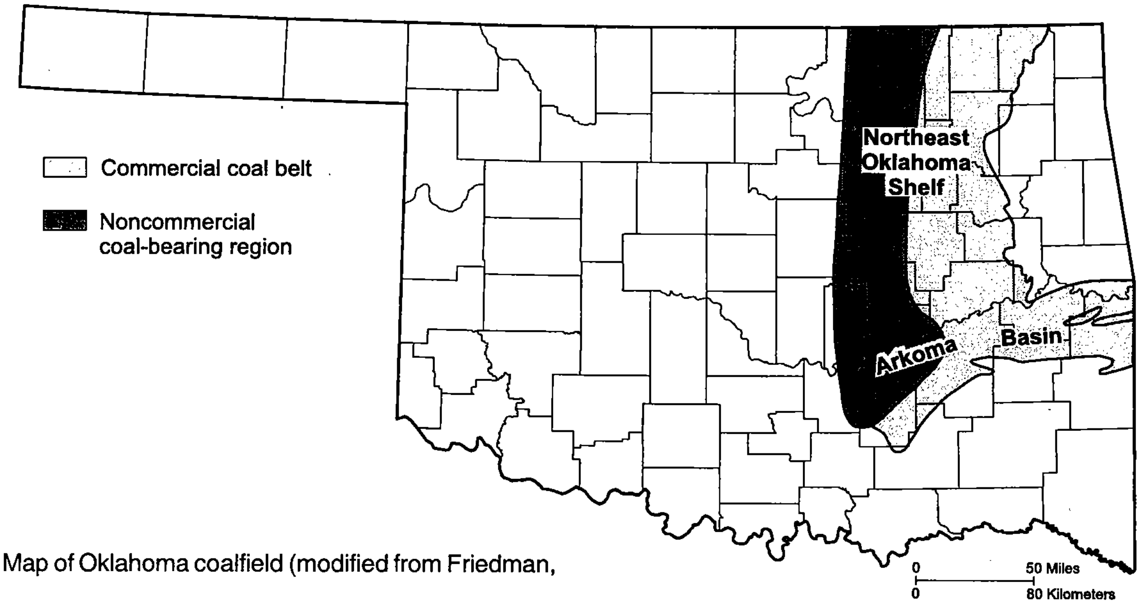


Figure 3. Map of Oklahoma coalfield (modified from Friedman, 1974).

as such at the time of this compilation. This evaluation is based on reported CBM completions, which may or may not have been connected to a gas pipeline. Likewise, some completions may have produced gas but subsequently have been plugged.

The Coalbed-Methane Completions table of the Oklahoma Coal Database was used to summarize data in this report. Each record (well completion) in the table lists operator, well name, API number, completion date, location (county, gas field, township-range-section, latitude-longitude), coal bed, production depth interval, initial gas potential and water rates, pressure information, and comments. Incomplete copies of Oklahoma Corporation Commission Form 1002A limited the data summaries for coal depth, initial gas potential, and produced water in this report. The database is available for viewing at or purchase from the Oklahoma Geological Survey. A searchable version of the Coalbed-Methane Completions table is accessible on the Internet through a link on the OGS web site (http://ogs.ou.edu/).

COALBED-METHANE ACTIVITY

Northeast Oklahoma Shelf

There were 1,725 CBM well completions reported in the shelf by 70 operators through December 2003. Completions are in Craig, Nowata, Okfuskee, Okmulgee, Osage, Pawnee, Rogers, Tulsa, and Washington Counties (Fig. 4). About 29% of the wells are recompletions of older conventional gas and oil wells and coalbed-methane wells. In ascending order (by coal as uppermost bed with number of completions in parentheses), the methane-producing coals include the Riverton coal (215) in the McAlester Formation; the Rowe (601) and Drywood (3) coals in the Savanna Formation; the Bluejacket (59) and Wainwright (1) coals in the Boggy Formation; the Weir-Pittsburg (113), Tebo (8), Mineral (1), Croweburg (37), Bevier (23), Iron Post (59), and Mulky (547) coals in the Senora Formation; and the Dawson (51) coal in the Holdenville Formation. Thus, these coal beds are in units of the Krebs, Cabaniss, and Marmaton Groups of the Desmoinesian Series (Fig. 5). The coal name was not reported for seven CBM wells.

Hemish (2002) correlated coals from the surface to subsurface in a 2,700-mi^2 area in the northeast Oklahoma shelf to assist operators in correctly identifying coal beds. Two type logs were designated in the northern and southern parts of the study area. Persistent marker beds were identified to correlate the coal beds.

The nomenclature of coal-bearing strata and coal beds in Kansas and Oklahoma are slightly different. The Kansas Geological Survey includes the Krebs and Cabaniss Formations in the Cherokee Group (Brady, 1997), whereas the Oklahoma Geological Survey assigns the Krebs and Cabaniss to group level in the Desmoinesian Series. The Rowe coal of Kansas and Missouri is equivalent to the Keota coal of Oklahoma; the Drywood coal of Missouri and Dry Wood coal of Kansas are equivalent to the Spaniard coal of Oklahoma (Hemish, 1990).

The Mulky coal is one of the most important CBM reservoirs in the northeast Oklahoma shelf. The Mulky, the uppermost coal in the Senora Formation, occurs at the base of the Excello Shale Member and varies in composition from pure to impure coal with increasing amounts of mineral matter.[1] Hemish (1986, p. 18) recognized the Mulky coal in three drill holes in northern Craig County, where its maximum thickness is 10 in.

[1] As defined by Schopf (1956), carbonaceous shale contains >50% mineral matter by weight or <30% carbonaceous matter by volume. According to the ASTM (1994), impure coal contains 25–50 weight % mineral matter as ash.

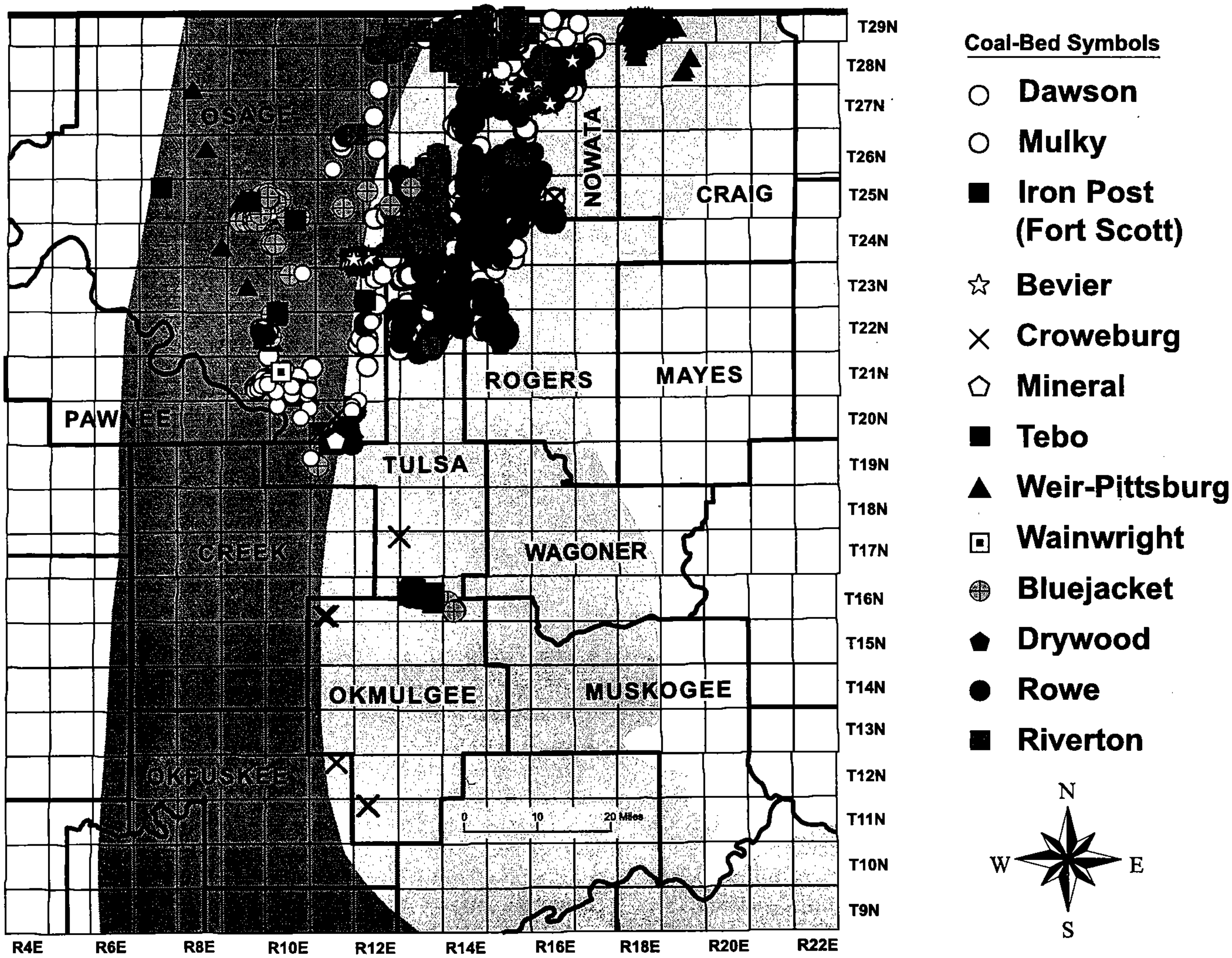


Figure 4. Distribution of coalbed-methane well completions by coal bed in the northeast Oklahoma shelf.

Hemish (2002, p. 3) indicated that: "The occurrence of the Mulky coal downdip to the west in Nowata, Washington, and Osage Counties has not been verified by the OGS from coring. It seems probable that the methane is being produced from the Excello black shale."

Figure 6 shows the depth range of CBM completions in 1,565 wells in the shelf. Coal beds were perforated at depths-to-top of coal of 256–2,459 ft, for an average depth of 1,046 ft. Although two to seven coal beds were perforated in 383 completions, only the shallowest coal depth was used in Figure 6. Three modes are apparent in Figure 6. The shallower mode represents mostly the Mulky coal (547 wells; includes commingled wells with the Mulky as the shallowest perforated coal) completed over a depth range of 256–1,733 ft; 358 wells were completed in only the Mulky coal.

The second mode represents mostly the Rowe coal (1,123 wells), completed over a depth range of 542–2,459 ft. The deepest coal completion (2,459 ft) in the shelf is in the Rowe coal in Osage County (Amvest West, 99 Drummond II well, sec. 23, T. 21 N., R. 9 E.).

The third mode represents mostly the Riverton coal (204 wells), completed over a depth range of 630–1,970 ft.

Initial-potential (IP) gas rates range from a trace to 359 Mcfd and average 31 Mcfd from 1,391 wells (Fig. 7). However, IP rates do not demonstrate the full potential of a CBM well because they reflect only the first of the three stages of a typical CBM production-decline curve: dewatering, stable production, and decline (see Schraufnagel, 1993, fig. 2). Figure 8 shows the relationship of depth and IP gas rate for CBM wells in the shelf. Single-coal-completion wells with the shallowest coals (256–377 ft) had IP rates of 1–50 Mcfd. Eighty-four CBM wells (including 27 wells with multiple coal completions) with the highest IP rates (>100 Mcfd) were from depths of 258–1,661 ft. The single-coal-completion well with the highest IP rate (278 Mcfd) in the shelf is the STP Incorporated 2-29 Kirkpatrick well (sec. 29, T. 29 N., R. 18 E.; Craig County) in the Weir-Pittsburg coal at a depth of 433 ft. The maps in Figures 9–12 highlight the Mulky, Weir-Pittsburg, Rowe, and Riverton CBM wells, respectively (including commingled wells) that exhibit generally higher IP rates—73 (15%) of 498

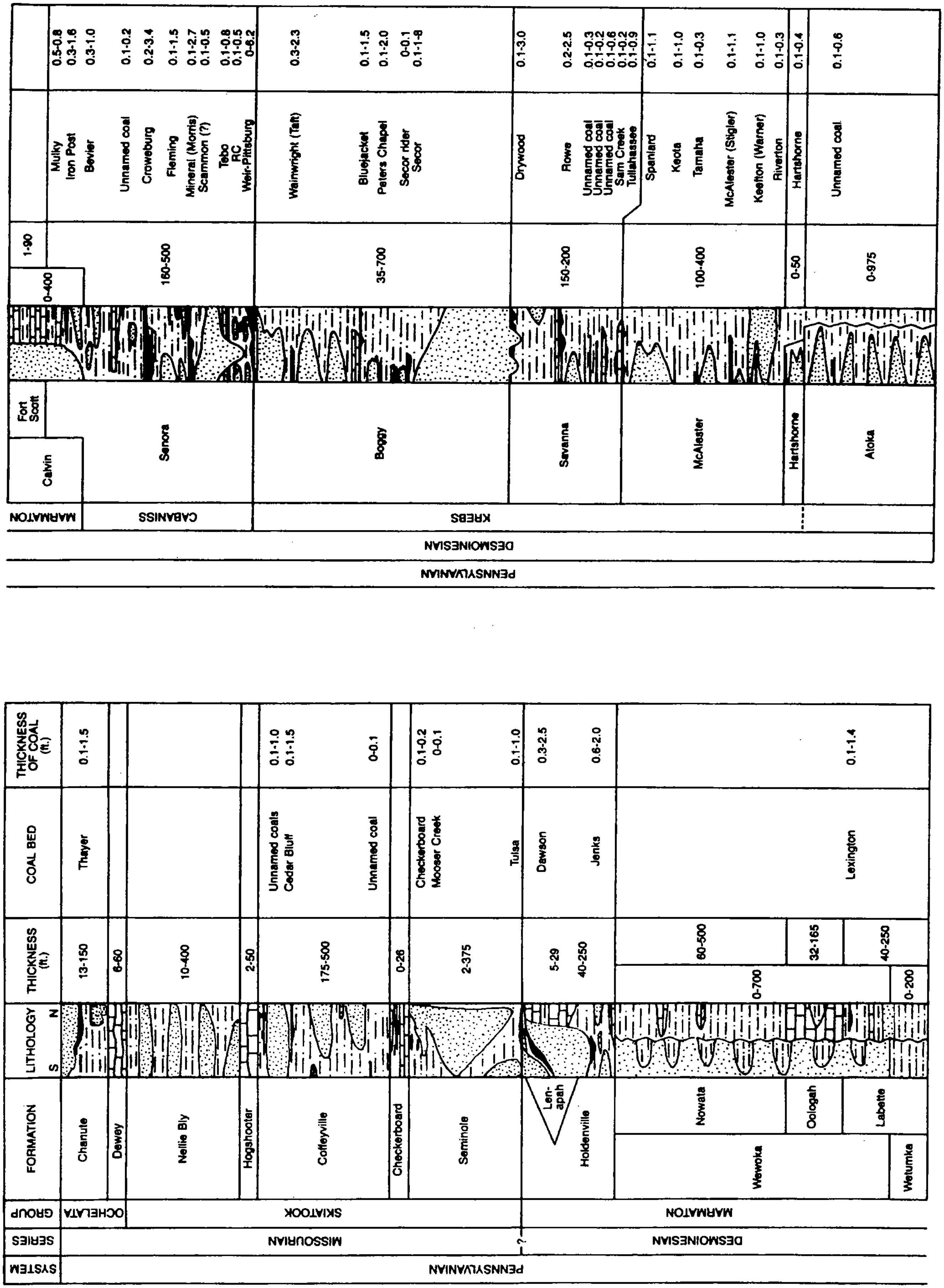


Figure 5. Generalized stratigraphy of coal-bearing strata of the northeast Oklahoma shelf (from Hemish, 1988).

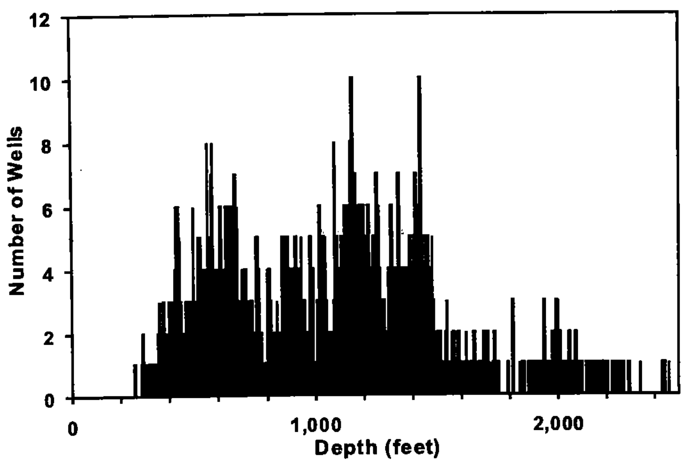


Figure 6. Histogram of coalbed-methane well completion depths in the northeast Oklahoma shelf.

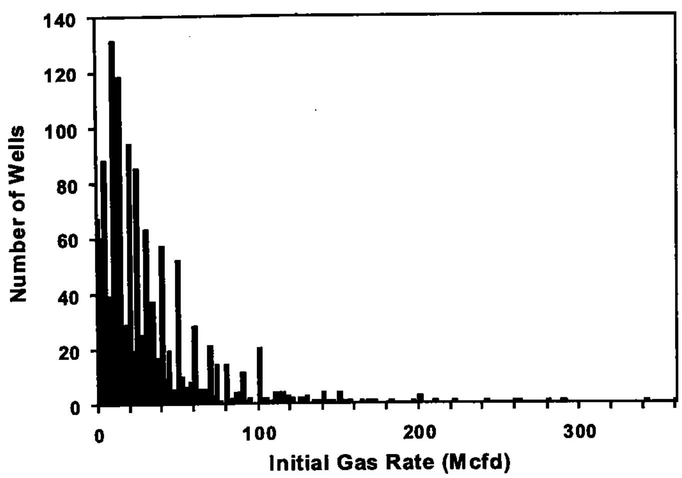


Figure 7. Histogram of initial-potential-gas rates (in thousand cubic feet of gas per day, Mcfd) in coalbed-methane well completions in the northeast Oklahoma shelf.

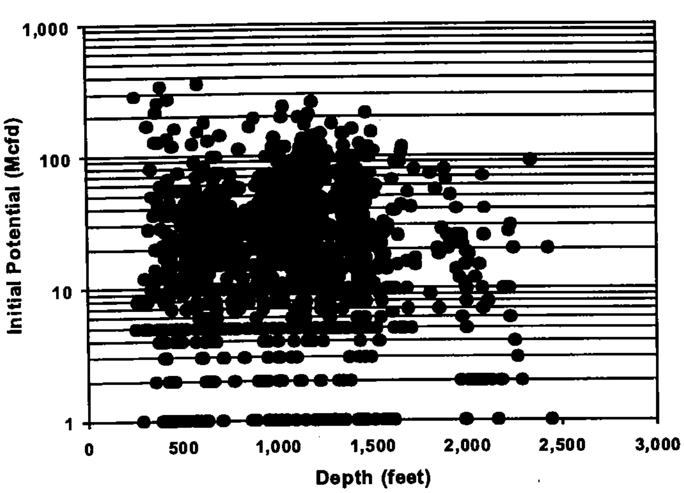


Figure 8. Scatter plot of initial-potential-gas rate (in thousand cubic feet of gas per day, Mcfd) and depth-to-top of coal in the northeast Oklahoma shelf.

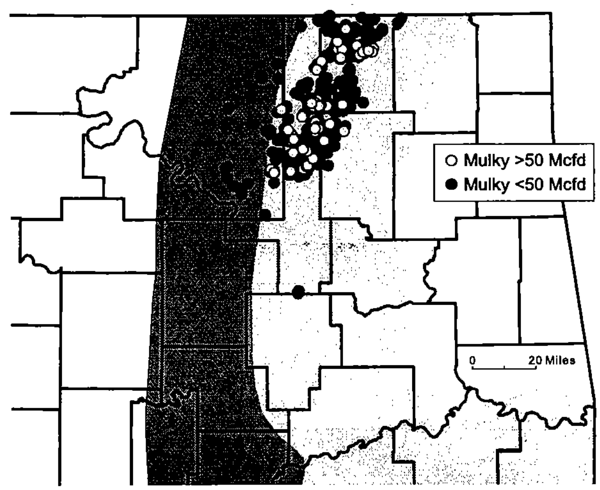


Figure 9. Distribution of well completions in the Mulky coal in the northeast Oklahoma shelf, showing wells with relatively high IP gas rates (in thousand cubic feet of gas per day, Mcfd).

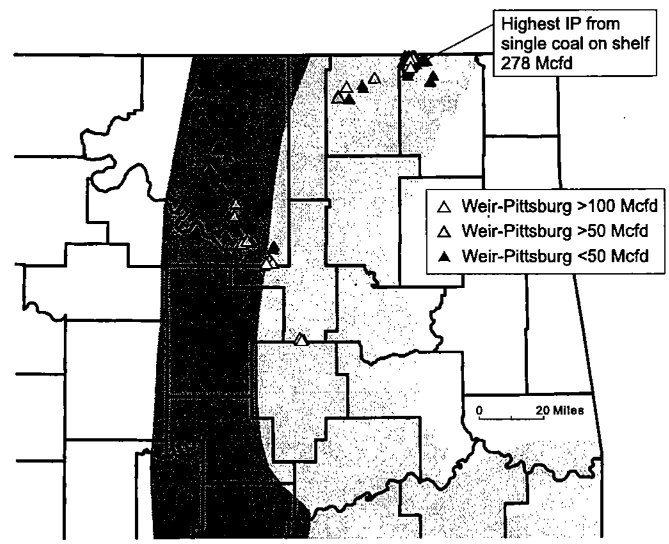


Figure 10. Distribution of well completions in the Weir-Pittsburg coal in the northeast Oklahoma shelf, showing wells with relatively high IP gas rates (in thousand cubic feet of gas per day, Mcfd).

Mulky wells with initial gas rates of 50–359 Mcfd, 21 (19%) of 109 Weir-Pittsburg wells with initial gas rates of 50–278 Mcfd (eight Weir-Pittsburg wells had IP >100 Mcfd), 118 (22%) of 534 Rowe wells with initial gas rates of 50–260 Mcfd (36 Rowe wells had IP >100 Mcfd), and 46 (24%) of 194 Riverton wells with initial gas rates of 50–150 Mcfd (11 Riverton wells had IP >100 Mcfd). The IP was not reported for coals in some wells.

Initial water rates in the shelf range from 0 to 5,061 barrels of water per day (bwpd) and average 68 bwpd from 1,408 wells (Fig. 13). Most of the water is believed to be formation water and not water from fracture stimulation. Because of generally poor water quality, these wells require disposal wells for the produced water. With the assistance of Cynthia Rice (U.S. Geo-

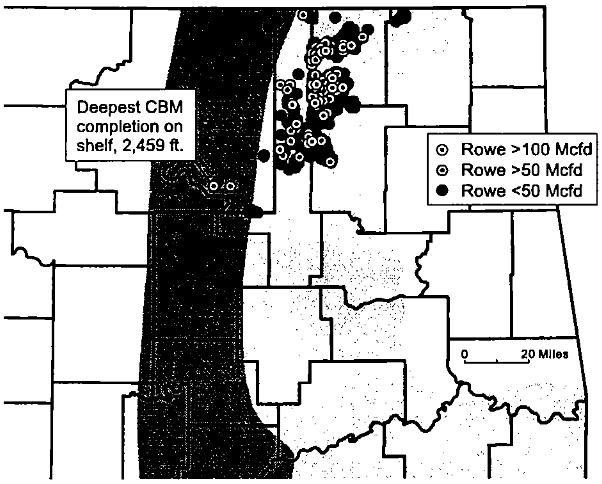


Figure 11. Distribution of well completions in the Rowe coal in the northeast Oklahoma shelf, showing wells with relatively high IP gas rates (in thousand cubic feet of gas per day, Mcfd).

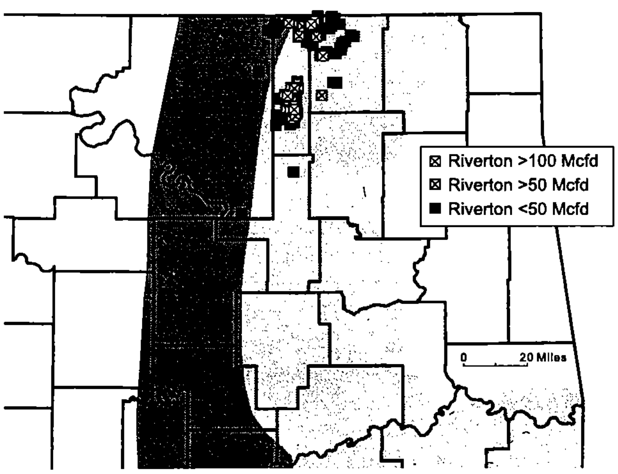


Figure 12. Distribution of well completions in the Riverton coal in the northeast Oklahoma shelf, showing wells with relatively high IP gas rates (in thousand cubic feet of gas per day, Mcfd).

logical Survey), water samples were collected from the Mulky and Rowe coals in four CBM wells in Nowata and Osage Counties in 2002. The water samples had 86,200–152,900 mg/L Total Dissolved Solids. In general, water volumes are not metered; therefore, the volume of disposed water and the effect of water production on gas rate are unknown.

Monthly gas production by well is reported on Form 1004/1005 (Measured Volume Report) by the Oklahoma Corporation Commission Oil & Gas Conservation Division. The information is available from the Oklahoma Corporation Commission web site (see "Oil and Gas Web Applications" at http://www.occ.state.ok.us/). Gas content and gas composition data are unpublished for coals in the northeast Oklahoma shelf.

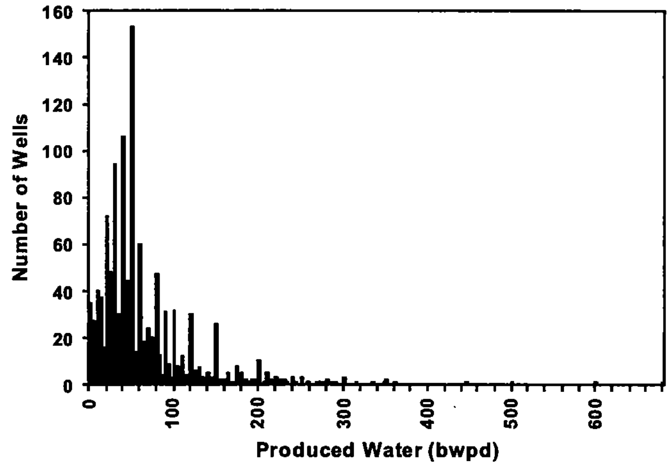


Figure 13. Histogram of initial water production rates (in barrels of water per day, bwpd) from coalbed-methane wells in the northeast Oklahoma shelf (excluding two wells with 1,201 and 5,061 bwpd).

API numbers for 1,725 CBM wells in the shelf were imported into the IHS Energy Group Production database for the southern Midcontinent. A subtotal of 1,420 wells (82%) had production data. Selecting coal-only wells reduced the subset to 837 wells (excluding numerous recompletions). Figure 14 summarizes gas production by year for wells in the shelf from 1994 to 2003. CBM production from wells in the shelf was 12.6 billion cubic feet of gas (Bcf) in 2003. Cumulative gas production in the shelf is 36.8 Bcf from 1994 to 2003.

Arkoma Basin

Figure 15 shows the locations of 1,171 CBM completions in the basin reported by 73 operators through December 2003. Completions are in Coal, Haskell, Hughes, Latimer, Le Flore, McIntosh, Muskogee, and Pittsburg Counties. In ascending order, the methane-

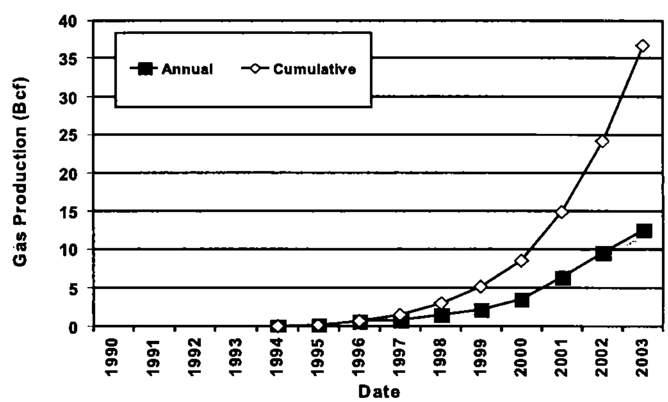


Figure 14. Graph showing annual and cumulative gas production (in billion cubic feet, Bcf) for coalbed-methane wells in the northeast Oklahoma shelf, 1994–2003 (gas production data supplied by Petroleum Information/Dwights LLC dba IHS Energy Group, © 2004).

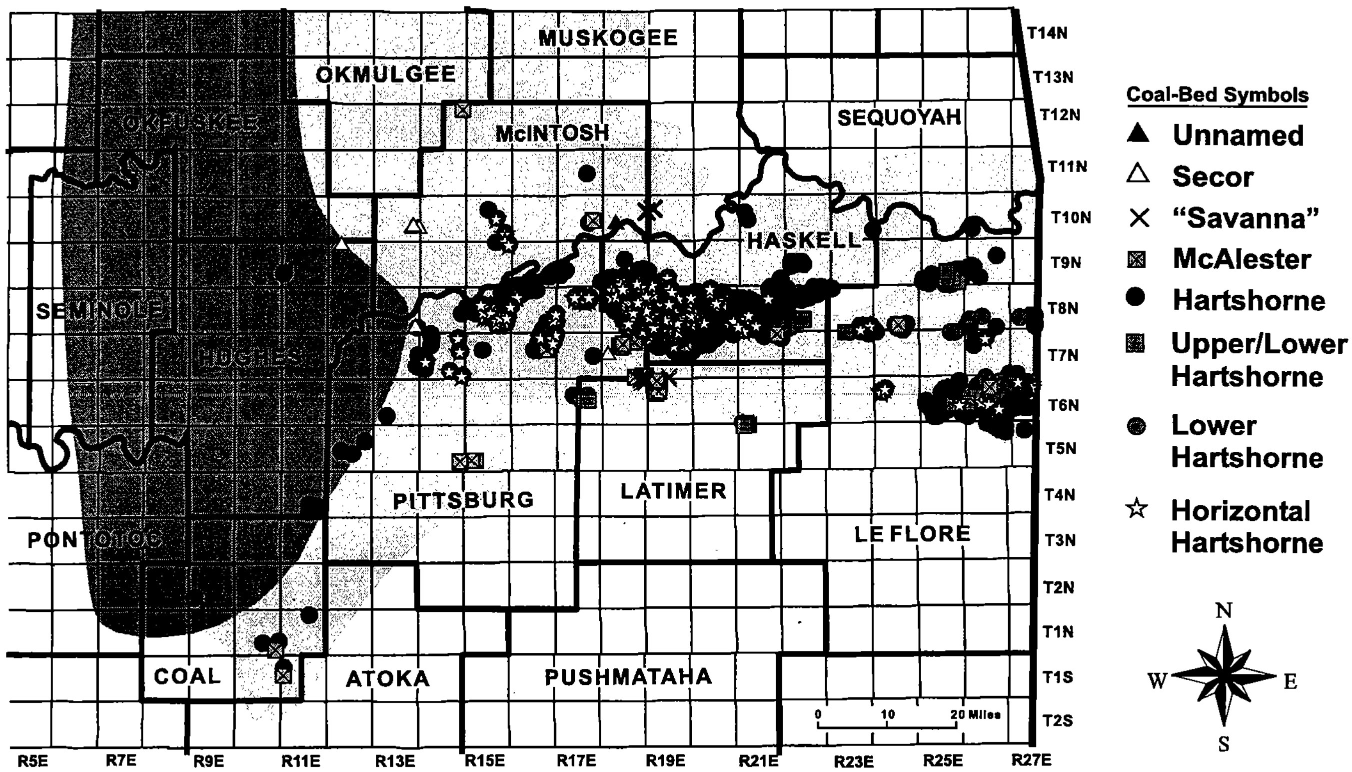


Figure 15. Distribution of coalbed-methane well completions by coal bed in the Arkoma Basin.

producing coals include the Hartshorne (undivided), Lower Hartshorne, and Upper Hartshorne (Hartshorne Formation), McAlester and "Savanna" (interpreted to be the McAlester coal, McAlester Formation; a completion in Coal County reported to be in the "Lehigh" coal is equivalent to the McAlester coal), Secor (Boggy Formation), and unnamed coal in the Krebs Group of Desmoinesian age (Fig. 16). Most (1,125) of the CBM completions in the Arkoma Basin are in Hartshorne coals.

Figure 17 shows the depth range of CBM completions in the basin. Coals were perforated at depths-to-top of coal of 284–4,397 ft, for an average of 1,529 ft in 1,058 wells. The three deepest completions (4,233–4,397 ft vertical depth) were horizontal CBM wells in the Hartshorne coal in Le Flore County (T. 6 N., R. 24 E.). Although two to three coals were perforated in 29 completions, only the shallowest coal depth was used in Figure 17.

The IP gas rates range from a trace to 2,316 Mcfd (average 136 Mcfd) from 943 wells (Fig. 18). Most (638 completions) wells produced 10–160 Mcfd. The highest IP rates (>330 Mcfd) were reported from 130 horizontal CBM wells in the Hartshorne coal. Based on 1,117 completions with depth and initial potential pairs, no relationship can be shown between IP gas rate and depth in the Arkoma Basin (depth of horizontal wells is based on vertical depth-to-top of coal) (Fig. 19). Low gas rates (<50 Mcfd) span the entire depth range. The shallowest well (284 ft) is a coal-mine–methane well. The Cohort Energy 1-32 Greenwood well (sec. 32, T. 9 N., R. 26 E.; Le Flore County) was drilled to the Hartshorne coal into a sealed part of the Georges Colliers, Inc., Pollyanna No. 8 underground coal mine and had an IP of 512 Mcfd of low–methane-content gas. The 336 wells (30% of 1,117) with the highest gas rates (>99 Mcfd) are from depths of 636–4,397 ft. Twelve horizontal CBM wells (T. 8 N., R. 17–19 E.) had an IP >1,000 Mcfd at a vertical depth of 1,302–2,632 ft. Theoretically, gas content increases with increasing rank, depth, and reservoir pressure (Kim, 1977; Scott and others, 1995; Rice, 1996). However, gas production depends on many variables, including gas content, coal thickness, water volume, cleat mineralogy, permeability, porosity, and stimulation method.

The first horizontal CBM well in Oklahoma was completed by Bear Productions in August 1998. By the end of December 2003, 287 horizontal CBM wells (25% of 1,171 completions) had been drilled in Haskell, Le Flore, McIntosh, and Pittsburg Counties by 18 operators (Fig. 20). The IP gas rates were 5–2,316 Mcfd (average of 358 Mcfd) at true vertical depths-to-top of coal of 752–4,397 ft in 280 horizontal CBM wells. Sixty-four (22% of 287) horizontal CBM wells in Haskell and Pittsburg Counties had IP gas rates >500 Mcfd (Fig. 20). Higher gas rates are possible in a horizontal well than in a single-bed vertical well by drilling at a high angle (perpendicular to oblique) to the face cleat to drain a larger area (Diamond and others, 1988). Horizontal CBM wells can drain as much as seven times the area of a vertical CBM well, depending on the lateral length (Stayton, 2002). Vertical CBM wells exhibit an elliptical drainage pattern, elongated parallel to the face cleat, as a result of the directional (anisotropic) permeability of the cleat (Diamond and others, 1988, fig. 4.1). Hori-

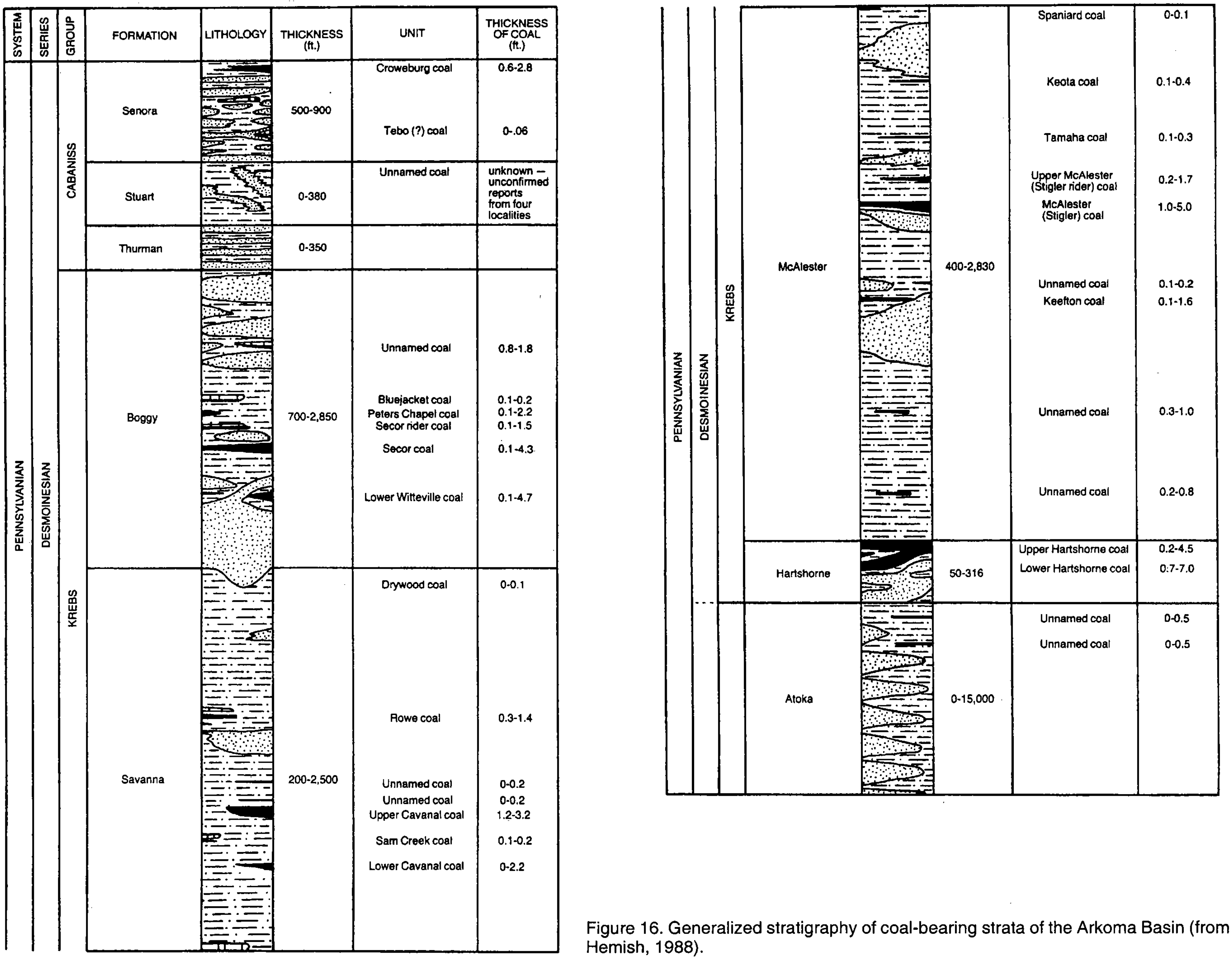


Figure 16. Generalized stratigraphy of coal-bearing strata of the Arkoma Basin (from Hemish, 1988).

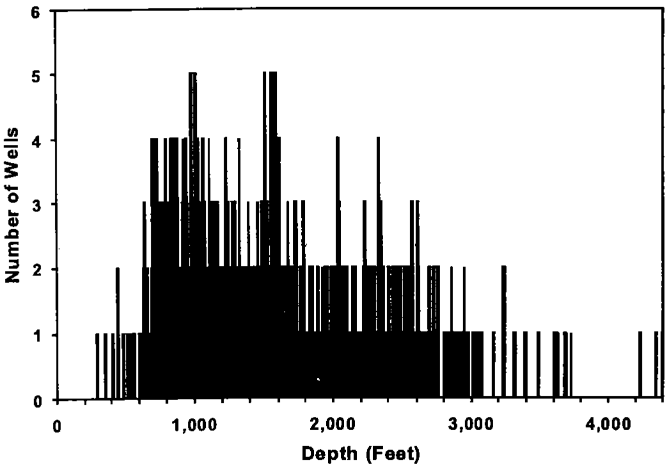


Figure 17. Histogram of coalbed-methane well completion depths in the Arkoma Basin.

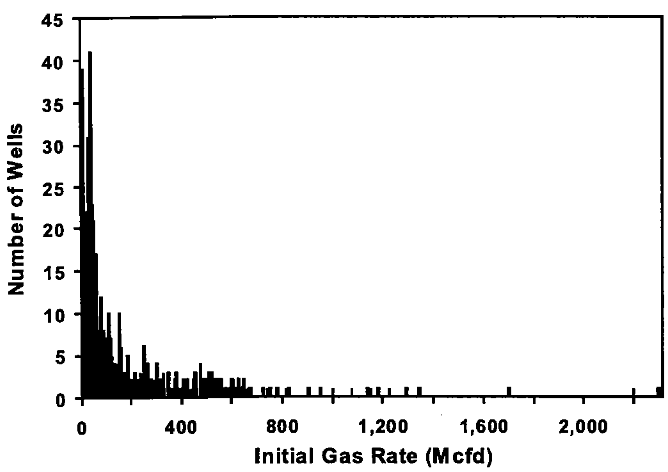


Figure 18. Histogram of initial-potential-gas rates (in thousand cubic feet per day, Mcfd) in coalbed-methane well completions in the Arkoma Basin.

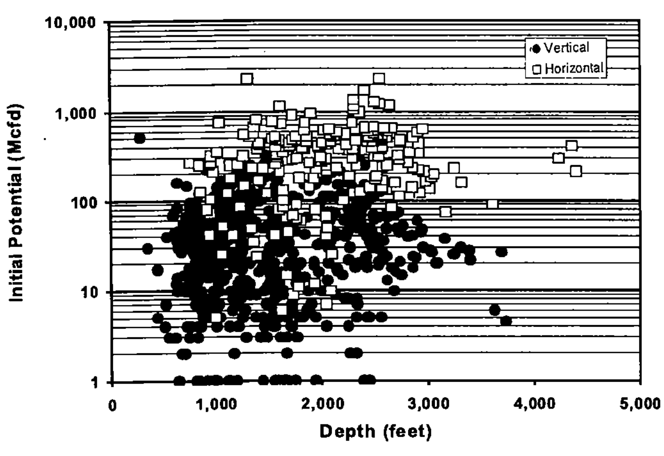


Figure 19. Scatter plot of initial-potential-gas rate (in thousand cubic feet per day, Mcfd) and depth-to-top of coal in the Arkoma Basin.

zontal CBM wells extend the elliptical drainage pattern along the length of the lateral. Horizontal CBM wells are completed openhole. The lateral distance within the coal for 260 horizontal CBM wells ranged from 439 to 4,034 ft, with an average of 1,854 ft. Figure 21 shows that, in general, higher initial gas rates are related to longer horizontal lateral lengths. The highest gas rates (IP >1,000 Mcfd) in wells with lateral lengths of 1,500–2,500 ft are related to a high permeability region (as noted above) and successful completion techniques, whereas lower gas rates (IP <500 Mcfd) in wells with any lateral length are related to low-permeability regions and completion complications, especially due to encountered faults.

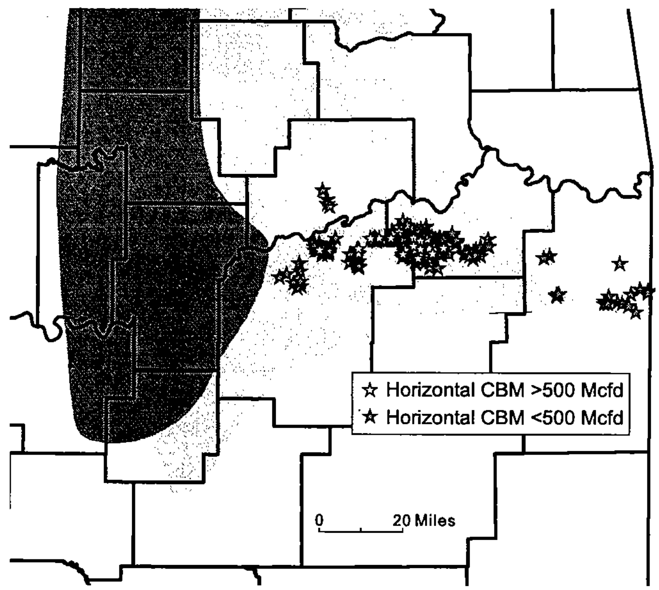


Figure 20. Distribution of horizontal coalbed-methane well completions in the Arkoma Basin, showing wells with relatively high IP gas rates (in thousand cubic feet per day, Mcfd).

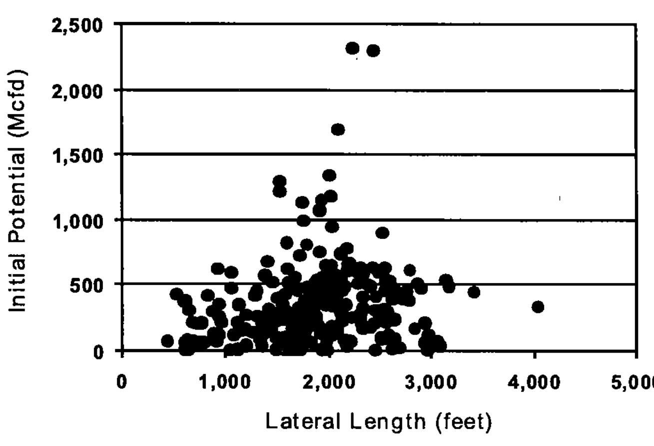


Figure 21. Scatter plot of initial-potential-gas rate (in thousand cubic feet per day, Mcfd) and horizontal lateral length in the Arkoma Basin.

Figure 22 shows a map of Hartshorne vertical CBM wells that have the highest initial potential gas rates—73 (10%) of 741 Hartshorne (including Upper and Lower Hartshorne) vertical CBM wells with initial gas rates of 100–512 Mcfd.

Andrews and others (1998) summarized published information on gas resources, gas content, gas composition, and cleating in Hartshorne coals. Measured gas contents range from 70 to 560 cubic ft/ton in high-volatile to low-volatile bituminous coal cores from depths of 175–3,651 ft in the Arkoma Basin.

Initial produced water rates range from 0 to 1,861 bwpd (average 30 bwpd) from 890 wells (Fig. 23). Most (529) CBM completions produced <20 bwpd. An undisclosed amount of initial water production is frac water introduced during fracture stimulation. Most Arkoma Basin CBM well completions are situated on the flanks of anticlines (Fig. 24) and tend to produce relatively little water. Most operators do not test or meter water production; therefore, water quality and quantity produced during the life of the well are unknown.

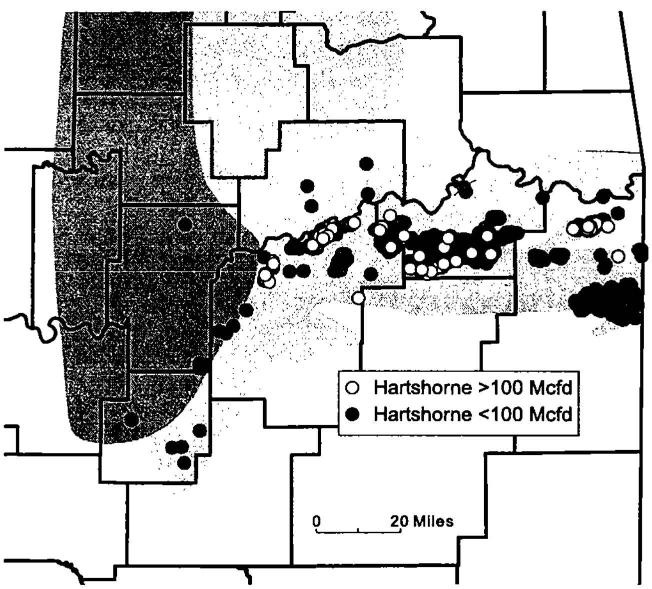


Figure 22. Distribution of well completions in the Hartshorne coal (excluding horizontal CBM wells) in the Arkoma Basin, showing wells with relatively high IP gas rates (in thousand cubic feet per day, Mcfd).

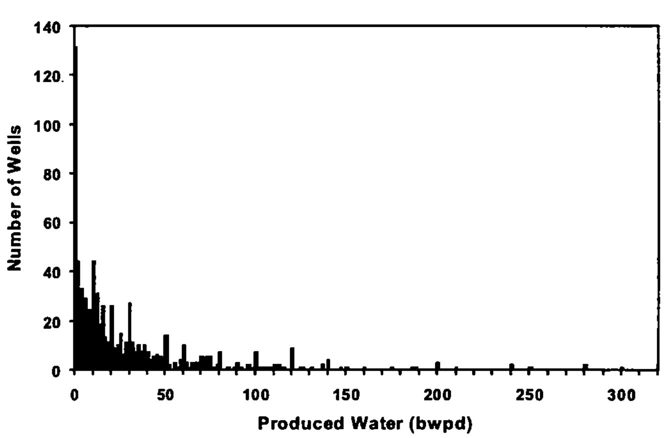


Figure 23. Histogram of initial water production rates (in barrels water per day, bwpd) from coalbed-methane wells in the Arkoma Basin (excluding one well with 1,861 bwpd).

API numbers for 1,171 CBM wells in the basin were imported into the IHS Energy Group Production database for the southern Midcontinent. A subtotal of 1,071 wells (91%) had production data. Selecting gas-only (excluding dry) wells reduced the subset to 972 wells. Figure 25 summarizes gas production by year for wells in the basin from 1989 to 2003. CBM production from 661 vertical wells was 9.1 Bcf in 2003. CBM production from 257 horizontal wells was 16.6 Bcf in 2003. Cumulative gas production in the basin is 79.2 Bcf from 1989 to 2003, 46.1 Bcf from 704 vertical wells and 33.1 Bcf from 274 horizontal wells.

CONCLUSIONS

The Oklahoma CBM play began in the Arkoma Basin in 1988 and then expanded to the northeast Oklahoma shelf in 1994. Through December 2003, 2,896 CBM completions were reported in Oklahoma—1,171 in the Arkoma Basin and 1,725 in the northeast Oklahoma shelf. The primary objectives are Hartshorne coals in the basin and the Mulky and Rowe coals in the shelf. Twenty-two percent (383 of 1,725) of the CBM completions in the shelf were multiple-coal completions with two to seven coal beds, whereas most of the CBM completions in the basin were single-coal completions.

Coal completion depths range from 256 to 2,459 ft and average 1,046 ft in 1,565 wells in the shelf, and 284–4,397 ft, averaging 1,529 ft in 1,058 wells in the basin.

Initial-potential gas rates range from a trace to 359 Mcfd (average 31 Mcfd) from 1,391 wells in the shelf, and a trace to 2,316 Mcfd (average 136 Mcfd) from 943 wells in the basin. The maximum initial gas rate was reported in the Hartshorne coal at a true vertical depth of 1,302 ft from a horizontal well in Haskell County.

Produced-water rates range from 0 to 5,061 bwpd (average 68 bwpd) from 1,408 wells in the shelf, and 0–1,861 bwpd (average 30 bwpd) from 890 wells in the basin.

From 1994 to 2003, 837 CBM wells in the shelf produced 36.8 Bcf gas. From 1989 to 2003, 972 CBM wells in the basin produced 79.2 Bcf gas, 46.1 Bcf from 704 vertical CBM wells, and 33.1 Bcf from 274 horizontal wells.

Low initial gas rates and minimal initial increase in gas production during dewatering are commonly attributed to formation damage caused by well stimulation, including the generation of coal fines that plug permeability. Present industry emphasis is on matching the completion techniques to the specific coal.

Future development of CBM in Oklahoma is promising, especially if natural gas prices remain high. Applications of horizontal drilling and established completion practices have demonstrated the potential for CBM in the Midcontinent USA.

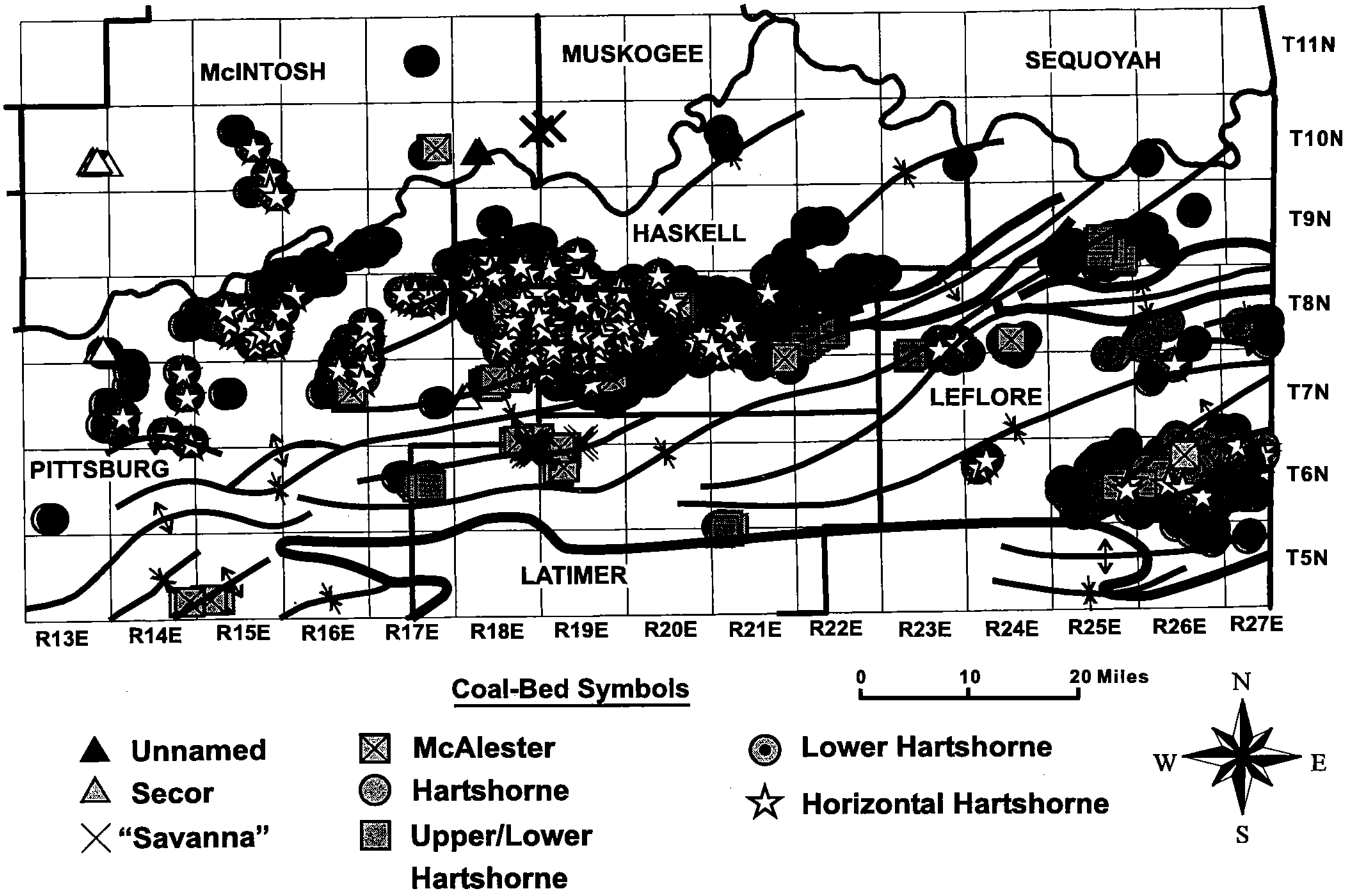


Figure 24. Major surface fold axes, Hartshorne coal outcrop (heavy line), and coalbed-methane well completions in the Arkoma Basin, Oklahoma. Structure modified from Arbenz (1956, 1989), Berry and Trumbly (1968), and Suneson (1998).

ACKNOWLEDGMENTS

I gratefully acknowledge that gas production data was supplied by Petroleum Information/Dwights LLC dba IHS Energy Group, © 2004, IHS Energy Group, all rights reserved. I thank Dan Boyd, Oklahoma Geological Survey, for comments on an earlier version of this paper.

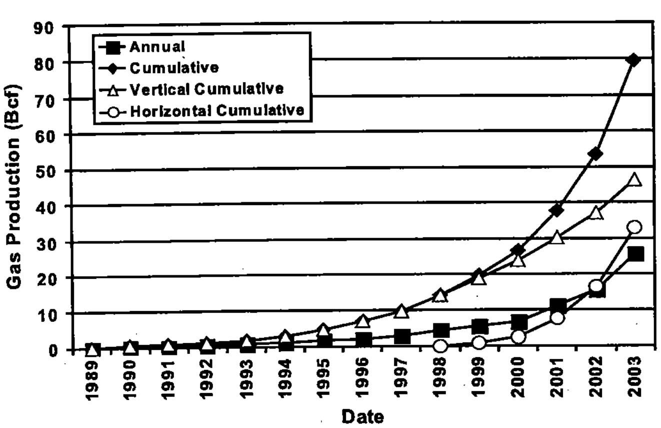


Figure 25. Graph showing annual and cumulative gas production (in billion cubic feet, Bcf) for coalbed-methane wells in the Arkoma Basin, 1989–2003 (gas production data supplied by Petroleum Information/Dwights LLC dba IHS Energy Group, © 2004).

REFERENCES CITED

Andrews, R. D.; Cardott, B. J.; and Storm, T., 1998, The Hartshorne play in southeastern Oklahoma: regional and detailed sandstone reservoir analysis and coalbed-methane resources: Oklahoma Geological Survey Special Publication 98-7, 90 p.

Arbenz, J. K., 1956, Tectonic map of Oklahoma showing surface structural features: Oklahoma Geological Survey Map GM-3, scale 1:750,000.

______1989, Ouachita thrust belt and Arkoma Basin, *in* Hatcher, R. D., Jr.; Thomas, W. A.; and Viele, G. W. (eds.), The Appalachian-Ouachita orogen in the United States: Geological Society of America, Boulder, Colorado, The Geology of North America, v. F-2, p. 621–634.

ASTM, 1994, Standard terminology of coal and coke, *in* Annual book of ASTM standards: gaseous fuels; coal and coke: American Society for Testing and Materials, sec. 5, v. 5.05, Standard D 121-94, p. 137–148.

Berry, R. M.; and Trumbly, W. D., 1968, Wilburton gas field, Arkoma Basin, Oklahoma, *in* Cline, L. M. (ed.), A guidebook of the western Arkoma Basin and Ouachita Mountains: Oklahoma City Geological Society Guidebook, p. 86–103.

Brady, L. L., 1997, Kansas coal resources and their potential for coalbed methane, *in* McMahan, G. (ed.), Transactions of the 1997 American Association of Petroleum Geologists Mid-Continent Section Meeting: Oklahoma City Geological Society, p. 150–163.

Campbell, M. R., 1929, The coal fields of the United States; general introduction: U.S. Geological Survey Professional Paper 100-A, 33 p.

Cardott, B. J., 2002, Introduction to coal geology of Oklahoma, *in* Cardott, B. J. (compiler), Fourth annual Oklahoma coalbed methane workshop: Oklahoma Geological Survey Open-File Report 9-2002, p. 34–55.

Deul, M.; and Kim, A. G., 1988, Methane control research: summary of results, 1964–1980: U.S. Bureau of Mines Bulletin 687, 174 p.

Diamond, W. P.; Elder, C. H.; and Jeran, P. W., 1988, Influence of geology on methane emission from coal, *in* Duel, M.; and Kim, A. G. (eds.), Methane control research: summary of results, 1964–80: U.S. Bureau of Mines Bulletin 687, p. 26–40.

Friedman, S. A., 1974, An investigation of the coal reserves in the Ozarks section of Oklahoma and their potential uses: Oklahoma Geological Survey Special Publication 74-2, 117 p.

_____2002, Coal geology of Oklahoma, *in* Keystone Coal Industry Manual: Primedia Business Magazines & Media Inc., Chicago, p. 584–590.

Hemish, L. A., 1986, Coal geology of Craig County and eastern Nowata County, Oklahoma: Oklahoma Geological Survey Bulletin 140, 131 p.

_____1988, Report of core-drilling by the Oklahoma Geological Survey in Pennsylvanian rocks of the northeastern Oklahoma coal belt, 1983–1986: Oklahoma Geological Survey Special Publication 88-2, 174 p.

_____1990, Lithostratigraphy and core-drilling, Upper Atoka Formation through Lower Senora Formation (Pennsylvanian), northeastern Oklahoma shelf area: Oklahoma Geological Survey Special Publication 90-2, 54 p.

_____2002, Surface to subsurface correlation of methane-producing coal beds, northeast Oklahoma shelf: Oklahoma Geological Survey Special Publication 2002-2, 22 p.

Kim, A. G., 1977, Estimating methane content of bituminous coalbeds from adsorption data: U.S. Bureau of Mines Report of Investigations 8245, 22 p.

Oklahoma Department of Mines, 2003, Annual report 2002: Oklahoma Mining Commission, Department of Mines, 54 p.

Rice, D. D., 1996, Geologic framework and description of coalbed gas plays, *in* Gautier, D. L.; and others (eds.), 1995 National assessment of United States oil and gas resources—results, methodology, and supporting data: U.S. Geological Survey Digital Data Series DDS-30, release 2, CD-ROM.

Sanderson, G. A.; and Berggren, L. W., 1998, White paper: update on application of §29 tax credit to coal seam gas: U.S. Environmental Protection Agency, 16 p. http://www.epa.gov/coalbed/clibrary/creports/natural_gas.htm

Schopf, J. M., 1956, A definition of coal: Economic Geology, v. 51, p. 521–527.

Schraufnagel, R. A., 1993, Coalbed methane production, *in* Law, B. E.; and Rice, D. D. (eds.), Hydrocarbons from coal: American Association of Petroleum Geologists Studies in Geology 38, p. 341–359.

Scott, A. R.; Zhou, N.; and Levine, J. R., 1995, A modified approach to estimating coal and coal gas resources: example from the Sand Wash Basin, Colorado: American Association of Petroleum Geologists Bulletin, v. 79, p. 1320–1336.

Stayton, R. J., 2002, Horizontal wells boost CBM recovery: American Oil & Gas Reporter, v. 45, no. 8, p. 71–75.

Suneson, N. H., 1998, Geology of the Hartshorne Formation, Arkoma Basin, Oklahoma: Oklahoma Geological Survey Guidebook 31, 74 p.

An Overview of Coal Gas Reservoir Properties: Core Holes from Western Interior Coal Region

Tim Pratt
TICORA Geosciences, Inc.
Arvada, Colorado

Matt Mavor
Tesseract Corporation
Park City, Utah

ABSTRACT.—TICORA Geosciences, Inc., collaborated with El Paso Production Company and Colt Energy, Inc., to collect detailed data sets from core samples collected in seven wells drilled in the Western Interior Coal (WIC) Region of the North American Midcontinent. The study, funded by the Gas Research Institute, included analysis of 197 canister desorption experiments collected from Middle Pennsylvanian (Desmoinesian) coal, coaly shale, and carbonaceous shale intervals in the Forest City, Cherokee, and Arkoma Basins. Desorbed gas composition, gas storage capacity, and coal characterization data (maceral composition, vitrinite reflectance, proximate and ultimate analyses, moisture-holding capacity, and helium density) were measured to supplement the desorption data. Analysis of these data resulted in three interdependent regional relationships between sorption properties and coal rank (i.e., thermal maturity). These are: (1) increasing gas content with increasing coal rank; (2) increasing gas storage capacity with increasing coal rank; and (3) decreasing sorption time (i.e., faster rate of diffusion) with increasing coal rank.

The thermal maturity of organic sediment deposited in Cherokee Group strata across the WIC Region generally increases to the south and west in the Cherokee and Forest City Basins and to the east in the Arkoma Basin. The coal rank data obtained during this study varied dramatically across the study area, in general agreement with published information, from subbituminous (Forest City Basin–Cherokee Group) to semi-anthracite (Arkoma Basin–Hartshorne Formation). Gas content and gas-in-place volume estimates for the Forest City Basin Cherokee reservoirs and the Arkoma Basin Hartshorne reservoirs ranged from roughly 1 to 680 scf/ton (in-situ basis) and 20 to 675 MMscf/160 acres, respectively.

Rank and gas content variations for reservoirs penetrated in a single core hole are also significant. For example, in the Forest City Basin Cherokee reservoirs, the maximum vitrinite reflectance and gas content can increase with depth by three V-types (0.46–0.70% vitrinite reflectance) and 220 scf/ton (60–280 scf/ton dry, ash-free basis), respectively, over a 510 ft stratigraphic interval (1,750–2,260 ft). These same respective parameters can increase with depth by nine V-types (1.51–2.30% vitrinite reflectance) and 475 scf/ton (270–745 scf/ton dry, ash-free basis) over a 1,720-ft stratigraphic interval (680–2,400 ft) for McAlester and Hartshorne reservoirs in the Arkoma Basin.

Methane was the primary gas present in the sorbed phase. The methane concentration was typically greater than 90% in Cherokee Basin Cherokee Group reservoirs and Arkoma Basin McAlester and Hartshorne reservoirs. Nitrogen, carbon dioxide, ethane, and heavier hydrocarbons were present in varying concentrations, which on average represented as much as 40% of the sorbed-phase gas in several Marmaton Group reservoirs in the Cherokee Basin.

The methane storage capacity calculated from sorption isotherm data was generally higher than the measured gas content, indicating gas undersaturation over much of the WIC Region. However, gas saturated or near saturation conditions were observed in several reservoirs, and the level of saturation does not appear to be related to or dependent on coal rank.

Pratt, Tim; and Mavor, Matt, 2005, An overview of coal gas reservoir properties: core holes from Western Interior Coal Region, *in* Cardott, B. J. (ed.), Unconventional energy resources in the southern Midcontinent, 2004 symposium: Oklahoma Geological Survey Circular 110, p. 83–103.

The highest cumulative gas-in-place volumes measured were in thin, high volatile A bituminous Cherokee Basin Cherokee Group reservoirs (623 MMscf/160 acres for 12 intervals with 14.3-ft net reservoir thickness) and in semi-anthracitic Hartshorne Formation coal seams in the Arkoma Basin (428–1,230 MMscf/160 acres for one to two coal beds with 6–9 ft net reservoir thickness).

The cooperative research project characterized coal and sorption properties for numerous coal seams that share similar depositional histories, but span a wide range of thermal maturities. However, as the density of core holes sampled over this large geographic area (85,000 mi^2) is low, caution should be taken to not quickly formulate decisions concerning the resource and production potential of the region based upon trends and other information presented in this study. Sorption properties are known to vary widely between locations for a given rank of coal.

Similar to earlier studies, the current study centered attention on coal properties, sorption behavior, and gas-resource volume. It also provides some estimates of possible gas productivity for specific core-hole locations. However, without valid well test data from which absolute permeability and reservoir pressure are quantified, it is impossible to accurately predict the gas production potential from the data presented herein.

INTRODUCTION

The Western Interior Coal (WIC) Region of the North American Midcontinent covers approximately 85,000 mi^2, extending through portions of Iowa, Nebraska, Kansas, Missouri, Oklahoma, and Arkansas. Three coal and shale-bearing basins are included in the region: Forest City, Cherokee, and Arkoma Basins. Principal coal gas reservoir targets are contained in the Middle Pennsylvanian Cherokee Group in the Forest City and Cherokee Basins and in the McAlester and Hartshorne Formations in the Arkoma Basin. Based upon limited subsurface and rock property data, the WIC Region is believed to contain roughly 77 billion tons of coal and 11 Tscf of coalbed natural gas (North American Coalbed Methane Resource Map, 2001).

Although production of coal gas began in 1985 in the Cherokee Basin and in 1988 in the Arkoma Basin, a sustained interest in commercial gas production from WIC Region coals did not take place until the mid-1990s. By late 2003, more than 3,500 coal gas wells had been drilled and completed in the WIC Region (Fig. 1) based upon available well completion data. As of early 2004, the region was delivering a modest volume of coal gas to the United States market (roughly 40 Bscf in 2003) from approximately 2,800 producing wells in Kansas and Oklahoma, including approximately 250 horizontal wells (Cardott, 2005 [this volume]; Newell and others, 2004).

Exploration and production of coal gas in numerous areas of the WIC Region continues to expand today for a variety of reasons including: (1) relatively inexpensive exploration, drilling, and completion costs; (2) accessibility to existing pipeline infrastructure; (3) the economic success of numerous recent wells in the southern portion of the Cherokee Basin (northeast Oklahoma shelf) and in much of the Arkoma Basin; and (4) greater industry focus on developing unconventional gas resources in conventionally mature areas. However, aside from the numerous gas content and gas-in-place resource studies that have been conducted since the 1970s, very little reservoir property data are currently available in the public domain; consequently, the ultimate potential for success in many areas of the WIC Region remains largely unknown.

In the Fall of 2000, the Gas Research Institute (GRI) implemented a cooperative research project in an effort to obtain and transfer high-quality reservoir property information over a broad area in the WIC Region to the unconventional-gas industry. The objective of the project was to provide a basic understanding of the regional geologic and reservoir property variations of Cherokee Group coal seams and equivalent coal-bearing formations across the WIC Region. El Paso Production Company (El Paso) and Colt Energy, Inc. (Colt Energy) agreed to become research partners and drilled and provided TICORA Geosciences Inc. access to seven core holes (Table 1; Fig. 2). Although the core hole density is sparse, the reservoirs sampled encompass the coal rank spectrum that operators are actively pursuing.

A total of 197 core intervals generally 1 ft in length were collected from numerous reservoirs penetrated by the seven core holes for canister desorption experiments to determine gas content. Desorption data were supplemented by additional laboratory data critical to adequately evaluate: (1) gas sorption properties (gas content, composition, diffusion rate, storage capacity, saturation); (2) reservoir composition (core lithology, proximate/ultimate analyses, maceral composition); (3) thermal maturity (gross calorific value, fixed carbon content, vitrinite reflectance); and (4) gas-in-place resource volume (thickness, grain density, in-situ moisture).

Modern methods were used for analyses to ensure that precision, accuracy, and consistency were maintained throughout the data-acquisition process (McLennan and others, 1995; Mavor and Nelson, 1997; Pratt and Baez, 2003). Desorption measurements were performed on coal, shaly coal (i.e., bone coal), coaly shale, and carbonaceous shale intervals to evaluate the range of the gas-in-place resource. Recently developed sorption isotherm equipment was used to measure gas storage capacity (Mavor and others, 2004).

Gas productivity is dependent upon these properties and on the pressure and permeability of the coal natural fracture system. Well test data, the most accurate source of pressure and permeability information, were

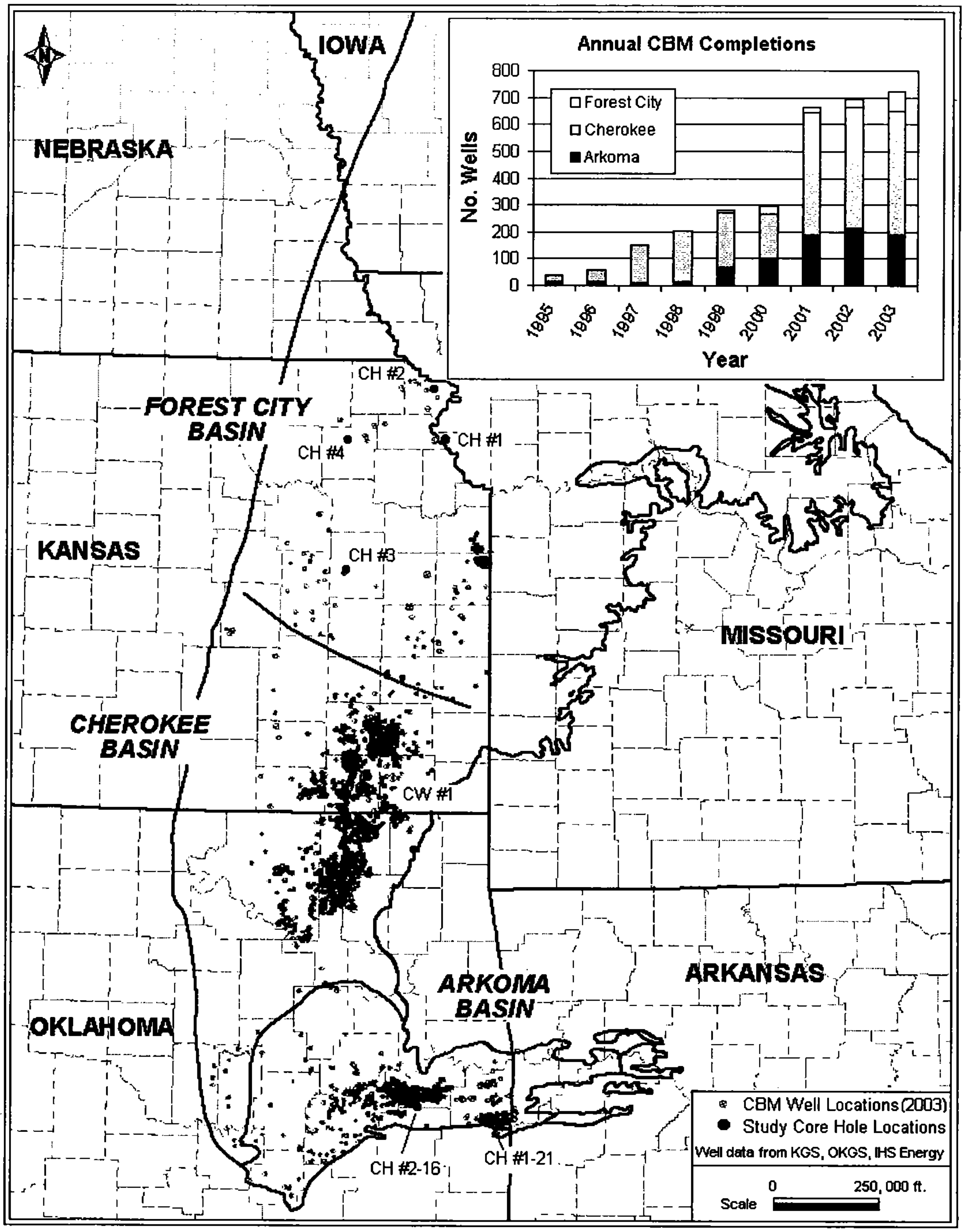


Figure 1. Exploration and development wells drilled in the Western Interior Coal Region through 2003, shown as gray dots. Control core holes for current study shown as black dots.

not collected as part of this project. Potential forecasts of possible gas productivity were made at several well locations for possible permeability distributions and an assumed reservoir pressure.

COAL AND SORPTION PROPERTY ESTIMATES

Detailed coal and sorption property analyses were made on 197 canister desorption experiments conducted on samples generally one foot in length recovered from seven core holes drilled in the Forest City, Cherokee, and Arkoma Basins (Table 1; Fig. 2). All coal, carbonaceous shale, coaly shale, and bone coal strata >6 in. in thickness were placed in canisters for desorption measurements. The reservoir thickness and relatively high mineral matter content of many of these samples would have precluded most operators from considering them as being potential reservoir targets. Desorption experiments were carried out at or near reservoir temperature. Unfortunately, reservoir temperatures were not

TABLE 1.—GRI Cooperative Research Core Hole Locations

Basin	Core hole names	Operator	County	State	Location
Forest City	FCB Core Hole #1 (CH #1)	El Paso	Platte	Missouri	sec. 26, T. 54 N., R. 37 W. (353 ft FNL & 1,626 ft FEL)
	FCB Core Hole #2 (CH #2)	El Paso	Doniphan	Kansas	sec. 6, T. 3 S., R. 21 E. (779 ft FNL & 1,896 ft FWL)
	FCB Core Hole #3 (CH #3)	El Paso	Osage	Kansas	sec. 35, T. 15 S., R. 14 E. (617 ft FSL & 1,673 ft FEL)
	FCB Core Hole #4 (CH #4)	El Paso	Jackson	Kansas	sec. 34, T. 6 S., R. 14 E. (1,051 ft FSL & 366 ft FEL)
Cherokee	Hinthorn #CW1 (CW #1)	Colt Energy	Montgomery	Kansas	sec. 14, T. 32 S., R. 16 E. (100 ft FSL & 2,740 ft FEL)
Arkoma	Core Hole #2-16 (CH #2-16)	El Paso	Haskell	Oklahoma	sec. 16, T. 6 N., R. 25 E. (800 ft FNL & 1,245 ft FEL)
	Core Hole #1-21 (CH #1-21)	El Paso	Le Flore	Oklahoma	sec. 21, T. 17 N., R. 20 E. (1,375 ft FNL & 1,980 ft FWL)

directly measured as a part of this study; the temperatures were provided by the cooperative partners.

In the Forest City Basin, a total of 140 canister desorption experiments were conducted on core samples recovered from four wells drilled in the Kansas City, Marmaton, and upper and lower Cherokee Groups in northwest Missouri and northeast Kansas (Table 2). In the Cherokee Basin, a total of 20 canister desorption experiments were conducted on core samples recovered from one well drilled in the Marmaton and Cherokee Groups in southeast Kansas (Table 2). Finally, in the Arkoma Basin, a total of 37 canister desorption experiments were conducted on core samples recovered from two wells drilled in the McAlester and Hartshorne Formations in east-central Oklahoma (Table 3).

Desorption samples were acquired, processed, and analyzed utilizing established and best-practice protocols to mitigate gas loss (during core recovery) and sample oxidation and desiccation, which are all known to have a deleterious affect on measurement accuracy (Pratt and others, 1999). Numerous critical and secondary analyses were conducted on the samples after desorption measurements were completed.

The lost gas content, which is the amount of gas lost during core recovery, never exceeded 20% of the total gas content for the study samples, and typically ranged from 1 to 10% of the total gas content. Low lost gas contents were due to fast wireline core recovery times. Because the lost gas content fractions were low, there was a high level of confidence associated with the accuracy of the total gas content estimates. The residual gas content, which is the gas volume remaining in the core samples after it is no longer possible to accurately measure desorbed gas volumes to 0.1 cm^3 at reservoir temperature and atmospheric pressure, typically represents <5% of the total gas content based upon numerous observations in many coal gas basins. This was the case for several samples from the Forest City Basin that were allowed to desorb to the residual gas level, which required as much as 12 months. Many desorption experiments for slower desorbing samples were terminated prematurely (i.e., after 8–12 months), and samples were crushed to liberate the gas remaining in the sample and to calculate total gas content. McAlester and Hartshorne Formation desorption samples typically required less than 3 months to reach the residual gas level.

Reservoir property estimates for reservoirs in the Kansas, Marmaton, and Cherokee Groups and the McAlester and Hartshorne Formations are summarized in Tables 4–11. Although a high sampling frequency was achieved within a core hole, the regional sample frequency was sparse. Therefore, data presented in the tables should not be considered to represent the average reservoir properties of the respective basin and formation from which they were collected.

Thermal Maturity

The thermal maturity of coal is ordinarily classified on the basis of ASTM coal rank. Classifications are either based upon gross calorific value (moist, mineral-matter-free basis) or fixed-carbon content (dry, mineral-matter–free basis) (ASTM, 1997). When mineral matter is present in abundant amounts (~25% by weight and greater), coal rank classifications are compromised. Mean maximum vitrinite reflectance is commonly used to accurately evaluate subtle differences in thermal

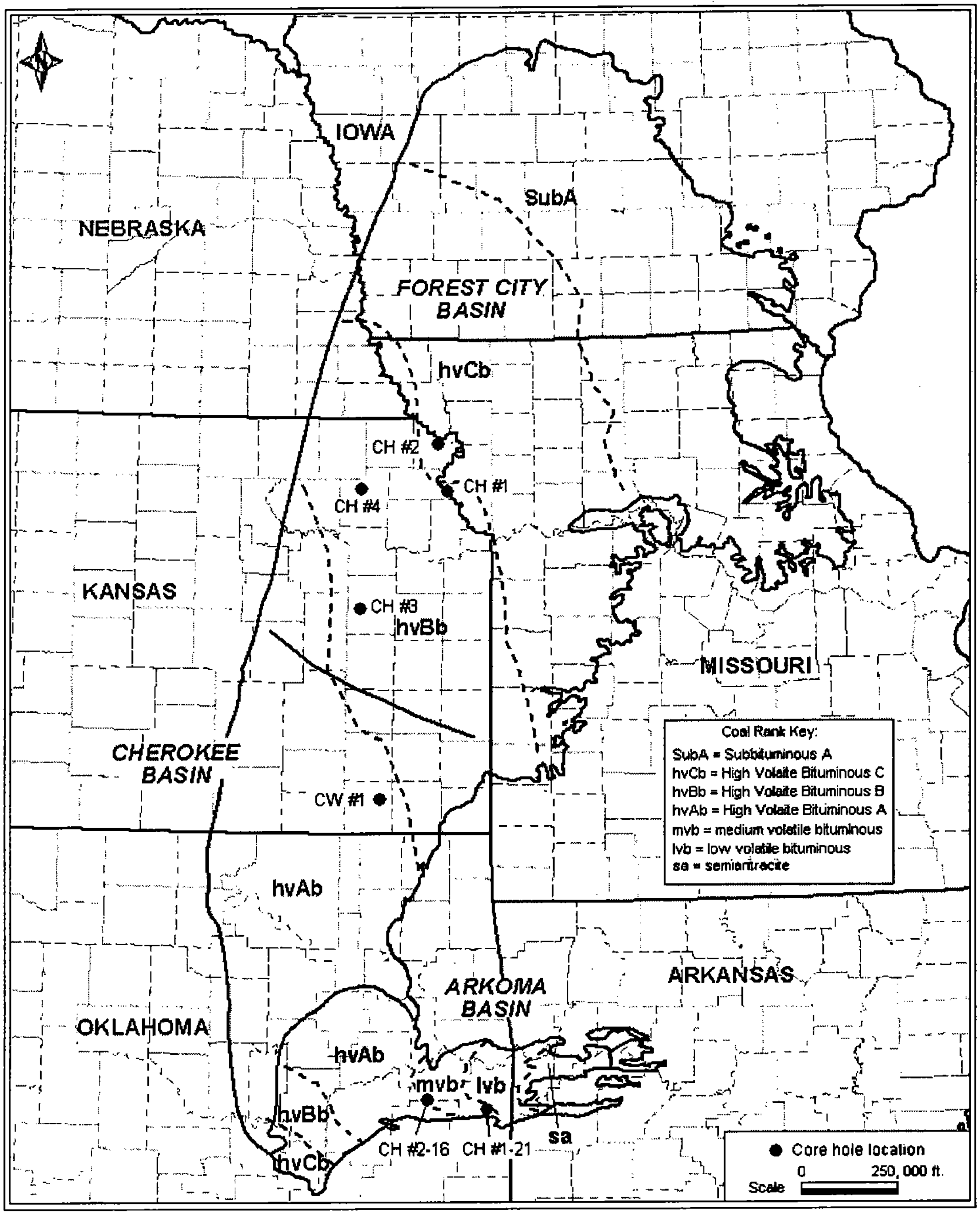


Figure 2. Core hole locations and generalized coal rank map for Western Interior Coal Region. Coal rank key shown in box.

maturity for coals of high volatile A bituminous and greater rank. The accuracy and precision of vitrinite reflectance data generally are not hindered by the presence of mineral matter.

Coal rank classifications were determined on 37 desorption samples. Coal rank data were not collected on the shallow Kansas City Group samples taken in the Forest City Basin or on the shallow Marmaton Group samples taken in the Cherokee Basin. The range of rank classifications determined on samples taken at the core holes (subbituminous to semi-anthracite) nearly spanned the entire coal rank spectrum, and certainly covered the range that is currently being assessed for coal-gas resource and production potential. The highest coal-rank classifications (low volatile bituminous–semianthracite) were measured in Haskell County, Oklahoma, at core hole CH #2-16 (McAlester and Hartshorne Formation coals) at depths between 680 and 2,400 ft. The coal rank of Cherokee Group samples taken at the CW #1 location was high volatile A bituminous between depths of 650 and 1,110 ft. The lowest rank classifications (subbituminous B–high volatile B bituminous) were measured in the Marmaton and upper Cherokee Group coals in the four Forest City Basin core holes.

TABLE 2.—Samples from the Forest City and Cherokee Basins

Basin	Well name		Kansas City Group	Marmaton Group	Cherokee Group Upper	Cherokee Group Lower
Forest City	CH #1	No. of samples:	5	1	8	17
		Continuous wireline core interval (drill depth, ft):	268.9–403.3	609.4–610.4	705.5–844.6	861.7–1,134.2
	CH #2	No. of samples:	2	1	8	23
		Continuous wireline core interval (drill depth, ft):	808.0–837.1	987.8–988.8	1,122.1–1,250.0	1,268.1–1,652.0
	CH #3	No. of samples:	7	8	9	17
		Continuous wireline core interval (drill depth, ft):	980.0–1,070.5	1,090.4–1,349.3	1,454.3–1,571.5	1,612.7–1,756.8
	CH #4	No. of samples:		1	9	24
		Continuous wireline core interval (drill depth, ft):		1,697.2–1,698.2	1,748.8–1,935.9	1,980.0–2,257.8
Cherokee	CW #1	No. of samples:		3	17	
		Continuous wireline core interval (drill depth, ft):		530.4–660.8	688.1–1,070.3	

TABLE 3.—Samples from the Arkoma Basin

Well name		Krebs Group McAlester Fm.	Krebs Group Hartshorne Fm.
CH #2-16	No. of samples:	10	6
	Continuous wireline core interval (drill depth, ft):	678.4–1,978.4	2,356.8–2,401.1
CH #1-21	No. of samples:	12	8
	Continuous wireline core interval (drill depth, ft):	381.0–2,073.1	2,449.5–2,457.8

High volatile A bituminous rank classifications were measured on lower Cherokee Group samples taken at depths >2,000 ft in core hole CH #4 (Jackson County, Kansas).

Coal ranks also varied dramatically with depth at the cooperative well locations. For example, the maximum vitrinite reflectance increased from 0.46 to 0.70% over a 510-ft drill depth interval (about 1,750–2,260 ft) for Cherokee Group reservoirs in the Forest City Basin. In the Arkoma Basin in the McAlester and Hartshorne Formation reservoirs, the maximum vitrinite reflectance increased from 1.51 to 2.30% over a 1,720-ft drill depth interval (about 680–2,400 ft).

Gas Content

Gas content values obtained from canister desorption experiments are typically reported on different bases, such as in-situ and dry, ash-free. To convert measured data to a dry, ash-free basis, the mass fraction of mineral matter and moisture is subtracted from the raw sample mass. Data are reported on a dry, ash-free basis where gas content comparisons are being made between individual coal reservoirs in a well, or between reservoirs at several locations. Gas contents reported on the in-situ basis include inherent mineral matter and moisture. Conversion of measured data to the in-situ

TABLE 4.—Reservoir Properties for Forest City Basin Kansas City Group Coals

Parameter	Units	Value		
Well		CH #1	CH #2	CH #3
Sampling Statistics				
Top of Sampled Interval	*feet*	268.9	808.0	980
Bottom of Sampled Interval	*feet*	403.3	837.1	1,070.5
Sampled Interval Thickness	*feet*	134.4	29.1	90.5
Number of Desorption Samples		5	2	7
Coal Properties				
Grain Density Range (In-Situ Basis)	*g/cm³*	2.09-2.56	2.03-2.11	2.07-2.61
Ash Content Range (In-Situ Basis)	*wt. %*	68.12-80.96	66.39-69.87	69.01-84.56
Moisture Holding Capacity Range	*wt. %*	05.91-08.24	06.49-06.53	04.87-08.72
Sulfur Content Range (In-Situ Basis)	*wt. %*	0.87-02.29	02.17-02.39	0.88-02.32
Maximum Vitrinite Reflectance Range	*%*			
Vitrinite Content Range (Mineral-Matter-Free Basis)	*Volume %*			
Inertinite Content Range (Mineral-Matter-Free Basis)	*Volume %*			
Liptinite Content Range (Mineral-Matter-Free Basis)	*Volume %*			
Clay Content Range (Maceral-Free Basis)	*Volume %*			
Quartz Content Range (Maceral-Free Basis)	*Volume %*			
Carbonate Content Range (Maceral-Free Basis)	*Volume %*			
Sulfide Content Range (Maceral-Free Basis)	*Volume %*			
Gross Calorific Value Range (Moist, Mineral-Matter-Free)	*Btu/lb*			
Fixed Carbon Range (Dry, Mineral-Matter-Free Basis)	*wt. %*			
Apparent Coal Rank Range (ASTM Method D 388)				
Apparent Coal Rank Range (Mean Maximum Vitrinite Reflectance)				
Methane Storage Capacity[a]				
Methane Storage Capacity Range (Dry, Ash-Free Basis)	*scf/ton*			
Methane Storage Capacity Range (In-Situ Basis)	*scf/ton*			
Reservoir Properties				
No. of Reservoirs (coal, coaly shale, carbonaceous shale)		3	2	3
Estimated Wet Reservoir Thickness	*feet*	5	2	7
Estimated Reservoir Temperature	*°F*	60	65	70
Estimated Pressure Gradient	*psi/ft*	0.400	0.400	0.400
Estimated Initial Reservoir Pressure Range	*psia*	122.1-175.8	337.7-349.3	406.5-442.7
Gas Content Range (Dry, Ash-Free Basis)	*scf/ton*	5.1-10.2	5.4-8.7	13.7-38.9
Gas Content Range (In-Situ Basis)	*scf/ton*	1.1-2.5	1.5-2.1	2.6-6.2
Diffusivity Range	*sec^{-1}*	1.39(08)–2.41(05)	8.64(09)-1.92(07)	2.61(08)–1.33(07)
Methane (CH_4) Concentration Range	*mole %*			
Ethane (C_2H_6) Concentration Range	*mole %*			
C_{3-10} Concentration Range	*mole %*			
Carbon Dioxide (CO_2) Concentration Range	*mole %*			
Nitrogen (N_2) Concentration Range	*mole %*			
Estimated Gas-In-Place Volume	*MMscf/160 acres*	3.66	1.59	12.95

[a]Calculated at estimated initial reservoir pressure.

basis requires the measurement of moisture-holding capacity at reservoir temperature (Pratt and Baez, 2003). Gas contents reported on an in-situ basis are representative of reservoir conditions and are used to compute the gas-in-place resource. Due to the abundance of inorganic material in many of the WIC Region study samples, which included bone coal, coaly shale, and carbonaceous shale intervals, in-situ gas contents were commonly significantly lower than the dry, ash-free gas-content values.

On an in-situ basis, the highest gas contents (about 400–680 scf/ton), comparable to values measured in the Fruitland coal gas "fairway" in the San Juan Basin, were measured in low-volatile bituminous and semi-anthracite samples from the McAlester and Hartshorne Formations of the Arkoma Basin. The lowest gas con-

TABLE 5.—Reservoir Properties for Forest City Basin Marmaton Group Coals

Parameter	Units	Value			
Well		CH #1	CH #2	CH #3	CH #4
Sampling Statistics					
Top of Sampled Interval	*feet*	609.4	987.8	1,090.4	1,697.2
Bottom of Sampled Interval	*feet*	610.4	988.8	1,349.3	1,698.2
Sampled Interval Thickness	*feet*	1.0	1.0	258.9	1.0
Number of Desorption Samples		1	1	8	1
Coal Properties					
Grain Density Range (In-Situ Basis)	*g/cm³*	1.55	1.55	2.07-2.65	2.26
Ash Content Range (In-Situ Basis)	*wt. %*	26.11	29.22	63.94-76.79	66.58
Moisture Holding Capacity Range	*wt. %*	09.68	12.30	03.92-08.44	02.92
Sulfur Content Range (In-Situ Basis)	*wt. %*	04.66	04.77	00.01-02.59	04.36
Maximum Vitrinite Reflectance	*%*			0.50	
Vitrinite Content (Mineral-Matter-Free Basis)	*Volume %*			88.45	
Inertinite Content (Mineral-Matter-Free Basis)	*Volume %*			8.25	
Liptinite Content (Mineral-Matter-Free Basis)	*Volume %*			3.30	
Clay Content (Maceral-Free Basis)	*Volume %*			40.00	
Quartz Content (Maceral-Free Basis)	*Volume %*			0.00	
Carbonate Content (Maceral-Free Basis)	*Volume %*			13.33	
Sulfide Content (Maceral-Free Basis)	*Volume %*			46.67	
Gross Calorific Value (Moist, Mineral-Matter-Free Basis)	*Btu/lb*				
Fixed Carbon (Dry, Mineral-Matter-Free Basis)	*wt. %*				
Apparent Coal Rank (ASTM Method D 388)					
Apparent Coal Rank (Mean Maximum Vitrinite Reflectance)				hvCb	
Methane Storage Capacity[a]					
Methane Storage Capacity Range (Dry, Ash-Free Basis)	*scf/ton*				
Methane Storage Capacity Range (In-Situ Basis)	*scf/ton*				
Reservoir Properties					
No. of Reservoirs (coal, coaly shale, carbonaceous shale)		1	1	4	1
Estimated Wet Reservoir Thickness	*feet*	1	1	8	1
Estimated Reservoir Temperature Range	*°F*	65	70	70-75	80
Estimated Pressure Gradient	*psi/ft*	0.400	0.400	0.400	0.400
Estimated Initial Reservoir Pressure Range	*psia*	258.3-258.6	409.6-410.0	450.7-554.2	693.4-693.8
Gas Content Range (Dry, Ash-Free Basis)	*scf/ton*	20.88	8.07	13.78-43.85	38.32
Gas Content Range (In-Situ Basis)	*scf/ton*	13.41	4.72	3.21-10.82	11.69
Diffusivity Range	*sec⁻¹*	2.26(08)	2.38(08)	9.11(09)–8.46(08)	3.67(08)
Methane (CH_4) Concentration Range	*mole %*				
Ethane (C_2H_6) Concentration Range	*mole %*				
$C_{3\text{-}10}$ Concentration Range	*mole %*				
Carbon Dioxide (CO_2) Concentration Range	*mole %*				
Nitrogen (N_2) Concentration Range	*mole %*				
Estimated Gas-In-Place Volume	*MMscf/160 acres*	4.53	1.59	26.78	5.74

[a]Calculated at estimated initial reservoir pressure.

tent values (about 5–45 scf/ton) were measured in the Kansas City and Marmaton Group samples of the Forest City Basin, which consisted predominantly of bone coal and carbonaceous shale. The in-situ gas contents for the Cherokee Group reservoirs in the Forest City and Cherokee Basins ranged between approximately 10 and 300 scf/ton, when carbonaceous shale intervals were excluded from the analysis.

Gas-content values for 37 desorption samples on which thermal maturity data were acquired were evaluated across the region. Gas-content values reported on a dry, ash-free basis were directly proportional to the maximum vitrinite reflectance (i.e., thermal maturity) of the coal (Fig. 3). Although this relationship is noteworthy, it should not be routinely used to predict dry, ash-free gas content values. It is apparent that the gas

TABLE 6.—Reservoir Properties for Forest City Basin Upper Cherokee Group Coals

Parameter	Units	Value			
Well		CH #1	CH #2	CH #3	CH #4
Sampling Statistics					
Top of Sampled Interval	*feet*	705.5	1,122.1	1,454.3	1,748.8
Bottom of Sampled Interval	*feet*	844.6	1,250.0	1,571.5	1,935.9
Sampled Interval Thickness	*feet*	139.1	127.9	117.2	187.1
Number of Desorption Samples		8	8	9	9
Coal Properties					
Grain Density Range (In-Situ Basis)	*g/cm³*	1.35-2.65	1.36-2.24	1.35-2.58	1.33-2.59
Ash Content Range (In-Situ Basis)	*wt. %*	08.90-84.56	10.65-68.12	08.49-83.50	08.92-80.81
Moisture Holding Capacity Range	*wt. %*	04.13-09.81	07.71-11.58	04.44-06.50	04.44-07.47
Sulfur Content Range (In-Situ Basis)	*wt. %*	00.03-06.11	01.21-05.57	00.15-05.07	01.77-07.67
Maximum Vitrinite Reflectance Range	*%*	0.46	0.43	0.55-0.58	0.54
Vitrinite Content Range (Mineral-Matter-Free Basis)	*Volume %*	86.74	75.65	87.99-90.72	81.01
Inertinite Content Range (Mineral-Matter-Free Basis)	*Volume %*	12.23	21.52	6.39-9.78	14.42
Liptinite Content Range (Mineral-Matter-Free Basis)	*Volume %*	1.02	2.83	2.23-2.89	4.58
Clay Content Range (Maceral-Free Basis)	*Volume %*	29.633	45.00	11.11-37.32	55.56
Quartz Content Range (Maceral-Free Basis)	*Volume %*	0.00	2.50	0.00-5.56	0.00
Carbonate Content Range (Maceral-Free Basis)	*Volume %*	14.81	7.50	0.00-54.93	4.76
Sulfide Content Range (Maceral-Free Basis)	*Volume %*	55.56	45.00	7.75-83.33	39.68
Gross Calorific Value (Moist, Mineral-Matter-Free Basis)	*Btu/lb*	13,467	12,646	12,997	13,641
Fixed Carbon (Dry, Mineral-Matter-Free Basis)	*wt. %*	81.24	79.44	78.72	79.09
Apparent Coal Rank (ASTM Method D 388)		hvBb	hvCb	hvCb	hvBb
Apparent Coal Range (Mean Maximum Vitrinite Reflectance)		subB	subB	hvBb	hvBb
Methane Storage Capacity[a]					
Methane Storage Capacity(Dry, Ash-Free)	*scf/ton*	133.1	188.7		101.9
Methane Storage Capacity (In-Situ)	*scf/ton*	105.5	134.7		71.8
Reservoir Properties					
No. of Reservoirs (coal, coaly shale, carbonaceous shale)		6	6	6	6
Estimated Wet Reservoir Thickness	*feet*	8	8	9	9
Estimated Reservoir Temperature Range	*°F*	65	70	75-80	80-85
Estimated Pressure Gradient	*psi/ft*	0.400	0.400	0.400	0.400
Estimated Initial Reservoir Pressure Range	*psia*	296.7-352.3	463.3-514.5	596.2-643.1	714.0-788.9
Gas Content Range (Dry, Ash-Free Basis)	*scf/ton*	8.48-40.76	8.37-19.75	17.88-75.36	8.31-59.14
Gas Content Range (In-Situ Basis)	*scf/ton*	1.63-27.85	1.85-12.71	2.47-35.64	1.21-36.59
Diffusivity Range	*sec^{-1}*	8.76(09)-1.72(06)	1.17(08)-3.39(07)	6.59(09)-2.69(07)	1.88(08)-4.97(07)
Methane (CH_4) Concentration Range	*mole %*	81.16	51.94-91.94	62.13-70.41	60.05-66.03
Ethane (C_2H_6) Concentration Range	*mole %*	0.81	0.09-0.80	3.36-8.61	4.36-11.44
C_{3-10} Concentration Range	*mole %*	0.38	0.00-1.50	1.45-5.08	2.17-8.39
Carbon Dioxide (CO_2) Concentration Range	*mole %*	0.00	0.00-4.39	0.00-0.69	0.00-1.64
Nitrogen (N_2) Concentration Range	*mole %*	17.59	7.97-40.66	15.90-32.37	14.14-31.71
Estimated Gas-In-Place Volume	*MMscf/160 acres*	27.44	21.56	57.05	64.60

[a]Calculated at estimated initial reservoir pressure.

content can vary significantly for a given coal rank (Fig. 3).

Gas content also varied dramatically with depth at any given core-hole location. For example, dry, ash-free gas content values increased from 60 to 280 scf/ton over a 510 ft drill depth interval (1,750–2,260 ft) for Cherokee Group reservoirs in the Forest City Basin. In the Arkoma Basin, McAlester and Hartshorne Formation reservoirs, the dry, ash-free gas content values increased from 270 to 745 scf/ton over a 1,720 ft drill depth interval (680–2,400 ft).

Sorbed-Gas Composition

Methane, nitrogen, carbon dioxide, ethane, and heavier hydrocarbons are all by-products of the coalifi-

TABLE 7.—Reservoir Properties for Forest City Basin Lower Cherokee Group Coals

Parameter	Units	Value			
Well		CH #1	CH #2	CH #3	CH #4
Sampling Statistics					
Top of Sampled Interval	*feet*	861.7	1,268.1	1,612.7	1,980.0
Bottom of Sampled Interval	*feet*	1,134.2	1,652.0	1,756.8	2,257.8
Sampled Interval Thickness	*feet*	272.5	383.9	144.1	277.8
Number of Desorption Samples		17	23	17	24
Coal Properties					
Grain Density Range (In-Situ Basis)	*g/cm^3*	1.32-2.54	1.33-2.51	1.34-2.45	1.41-2.45
Ash Content Range (In-Situ Basis)	*wt. %*	05.41-84.42	08.51-80.98	08.68-77.49	12.78-81.67
Moisture Holding Capacity Range	*wt. %*	04.11-09.97	04.27-09.74	02.67-11.84	02.56-09.41
Sulfur Content Range (In-Situ Basis)	*wt. %*	00.27-07.01	00.81-10.82	00.77-07.50	00.85-08.27
Maximum Vitrinite Reflectance Range	*%*	0.53-0.63	0.42-0.51	0.58-0.68	0.66-0.70
Vitrinite Content Range (Mineral-Matter-Free Basis)	*Volume %*	82.68-87.89	61.26-75.85	66.08-84.67	52.62-80.98
Inertinite Content Range (Mineral-Matter-Free Basis)	*Volume %*	9.03-12.93	16.27-30.53	10.81-26.91	16.78-37.11
Liptinite Content Range (Mineral-Matter-Free Basis)	*Volume %*	3.08-4.39	5.03-8.21	4.01-7.39	2.03-10.27
Clay Content Range (Maceral-Free Basis)	*Volume %*	0.00-53.33	68.00-81.69	2.33-92.19	35.71-58.49
Quartz Content Range (Maceral-Free Basis)	*Volume %*	0.00-0.00	0.00-0.84	0.00-7.69	0.00-4.35
Carbonate Content Range (Maceral-Free Basis)	*Volume %*	0.00-13.04	0.00-5.04	0.00-53.76	1.89-40.00
Sulfide Content Range (Maceral-Free Basis)	*Volume %*	36.96-100.00	14.08-32.00	7.42-97.67	10.00-51.79
Gross Calorific Value Range (Moist, Mineral-Matter-Free)	*Btu/lb*	12,588-13,709	12,922-13,186	13,986	14,407
Fixed Carbon Range (Dry, Mineral-Matter-Free Basis)	*wt. %*	78.54-87.29	72.85-77.64	77.99-82.78	84.51
Apparent Coal Rank Range (ASTM Method D 388)		hvBb	hvCb-hvBb	hvBb	hvAb
Apparent Coal Rank Range (Mean Maximum Vitrinite Reflectance)		hvBb	subB -hvBb	hvBb	hvBb-hvAb
Methane Storage Capacity[a]					
Methane Storage Capacity Range (Dry, Ash-Free Basis)	*scf/ton*	208.9-232.5	106.7	280.3	
Methane Storage Capacity Range (In-Situ Basis)	*scf/ton*	155.1-194.2	55.0	188.0	
Reservoir Properties					
No. of Reservoirs (coal, coaly shale, carbonaceous shale)		11	11	9	13
Effective Wet Reservoir Thickness	*feet*	16.37	19.89	17.45	21.28
Estimated Reservoir Temperature Range	*°F*	65-70	70-80	80	85-90
Estimated Pressure Gradient	*psi/ft*	0.400	0.400	0.400	0.400
Estimated Initial Reservoir Pressure Range	*psia*	359.2-468.2	521.7-675.3	659.6-717.2	806.5-917.6
Gas Content Range (Dry, Ash-Free Basis)	*scf/ton*	28.92-163.38	17.89-51.20	31.87-322.77	24.99-132.74
Gas Content Range (In-Situ Basis)	*scf/ton*	2.17-117.85	4.66-40.55	8.57-141.60	2.63-102.77
Diffusivity Range	*sec^{-1}*	2.55(08)-3.27(06)	2.03(08)-6.13(07)	2.68(08)-4.97(07)	1.15(08)-8.56(07)
Methane (CH_4) Concentration Range	*mole %*	86.76-96.94	80.98	73.63-92.52	83.59
Ethane (C_2H_6) Concentration Range	*mole %*	0.41-0.76	0.56	0.28-2.00	6.46
C_{3-10} Concentration Range	*mole %*	0.00-0.31	0.42	0.00-1.52	4.41
Carbon Dioxide (CO_2) Concentration Range	*mole %*	0.00-0.92	3.48	1.20-3.20	2.06
Nitrogen (N_2) Concentration Range	*mole %*	2.00-12.04	56.92	5.25-24.37	38.41
Estimated Gas-In-Place Volume	*MMscf/160 acres*	310.30	160.60	390.30	336.29

[a]Calculated at estimated initial reservoir pressure.

cation process and must be accounted for to determine gas storage capacity and produced gas composition. One method to evaluate the composition of the sorbed gas is to analyze the composition of numerous samples taken from desorption canisters over the duration of the desorption experiments.

Sorbed gas composition determinations were attempted on 47 canister experiments taken in various coal gas reservoirs or potential reservoirs over the WIC Region. It was impractical to characterize the sorbed phase gas composition in every reservoir during this study due to the sheer number of coal and coaly shale intervals sampled as part of this study. Determinations of sorbed phase gas composition were not attempted in the Kansas City Group samples taken in the Forest City Basin because desorbed gas volumes were too small to

TABLE 8.—Reservoir Properties for Cherokee Basin Marmaton and Cherokee Group Coal

Parameter	Units	Value	
Well		CW #1	
Sampling Statistics			
Group		Marmaton	Cherokee
Top of Sampled Interval	*feet*	530.4	688.1
Bottom of Sampled Interval	*feet*	660.8	1,070.3
Sampled Interval Thickness	*feet*	130.4	382.2
Number of Desorption Samples		3	17
Coal Properties			
Grain Density Range (In-Situ Basis)	*g/cm^3*	2.20-2.47	1.30-2.35
Ash Content Range (In-Situ Basis)	*wt. %*	70.33-83.23	05.63-80.69
Moisture Holding Capacity Range	*wt. %*	03.15-04.52	01.95-09.86
Sulfur Content Range (In-Situ Basis)	*wt. %*	01.40-02.19	01.37-10.28
Maximum Vitrinite Reflectance	*%*		0.87
Vitrinite Content (Mineral-Matter-Free Basis)	*Volume %*		79.84
Inertinite Content (Mineral-Matter-Free Basis)	*Volume %*		14.31
Liptinite Content (Mineral-Matter-Free Basis)	*Volume %*		5.85
Clay Content (Maceral-Free Basis)	*Volume %*		0.00
Quartz Content (Maceral-Free Basis)	*Volume %*		0.00
Carbonate Content (Maceral-Free Basis)	*Volume %*		0.00
Sulfide Content (Maceral-Free Basis)	*Volume %*		100.00
Gross Calorific Value (Moist, Mineral-Matter-Free Basis)	*Btu/lb*		15,037
Fixed Carbon (Dry, Mineral-Matter-Free Basis)	*wt. %*		89.11
Apparent Coal Rank (ASTM Method D 388)			hvAb
Apparent Coal Rank (Mean Maximum Vitrinite Reflectance)			hvAb
Methane Storage Capacity[a]			
Methane Storage Capacity (Dry, Ash-Free Basis)	*scf/ton*		320.8
Methane Storage Capacity (In-Situ Basis)	*scf/ton*		291.3
Reservoir Properties			
No. of Reservoirs (coal, coaly shale, carbonaceous shale)		3	13
Effective Wet Reservoir Thickness	*feet*	3.00	14.28
Estimated Reservoir Temperature Range	*°F*	80	80-90
Estimated Pressure Gradient	*psi/ft*	0.400	0.400
Estimated Initial Reservoir Pressure Range	*psia*	226.7-278.8	289.7-442.6
Gas Content Range (Dry, Ash-Free Basis)	*scf/ton*	83.86-160.21	151.58-331.30
Gas Content Range (In-Situ Basis)	*scf/ton*	19.63-28.31	40.47-300.74
Diffusivity Range	*sec^{-1}*	7.87(09)-1.20(08)	9.51(09)-3.83(07)
Methane (CH_4) Concentration Range	*mole %*	58.37-63.26	82.25-98.28
Ethane (C_2H_6) Concentration Range	*mole %*	5.26-13.54	0.09-5.89
$C_{3\text{-}10}$ Concentration Range	*mole %*	4.82-15.15	0.00-7.99
Carbon Dioxide (CO_2) Concentration Range	*mole %*	2.31-9.45	1.16-2.47
Nitrogen (N_2) Concentration Range	*mole %*	5.53-9.45	0.12-5.39
Estimated Gas-In-Place Volume	*MMscf/160 acres*	35.24	623.10

[a]Calculated at estimated initial reservoir pressure.

analyze accurately. Two attempts to characterize the sorbed gas composition in the Forest City Basin Marmaton Group samples failed for the same reason.

The composition of numerous gas samples collected from 45 canister desorption samples were determined in the upper and lower Cherokee Group reservoirs in the Forest City Basin, Marmaton and Cherokee Group reservoirs in the Cherokee Basin, and McAlester and Hartshorne Formation reservoirs in the Arkoma Basin. Suspect data were removed, and the remaining data were analyzed and combined to provide average results for numerous reservoirs sampled in each group or

TABLE 9.—Reservoir Properties for Arkoma Basin McAlester Formation Coal

Parameter	Units	Value	
Well		CH # 2-16	CH # 1-21
Sampling Statistics			
Top of Sampled Interval	*feet*	678.4	831.0
Bottom of Sampled Interval	*feet*	1,978.4	2,073.1
Sampled Interval Thickness	*feet*	1,300	1,242.1
Number of Desorption Samples		10	12
Coal Properties			
Grain Density Range (In-Situ Basis)	g/cm^3	1.48-2.64	1.31-2.56
Ash Content Range (In-Situ Basis)	*wt. %*	14.66-86.66	06.85-88.41
Moisture Holding Capacity Range	*wt. %*	02.58-06.81	01.85-04.12
Sulfur Content Range (In-Situ Basis)	*wt. %*	00.43-08.59	00.15-08.14
Maximum Vitrinite Reflectance Range	*%*	1.51-1.84	0.95-1.05
Vitrinite Content Range (Mineral-Matter-Free Basis)	*Volume %*	89.61-97.44	86.96-93.13
Inertinite Content Range (Mineral-Matter-Free Basis)	*Volume %*	2.56-10.39	6.07-9.40
Liptinite Content Range (Mineral-Matter-Free Basis)	*Volume %*	0.00-0.00	0.00-5.26
Clay Content Range (Maceral-Free Basis)	*Volume %*	21.05-95.82	36.36-79.59
Quartz Content Range (Maceral-Free Basis)	*Volume %*	0.00-0.00	0.00-14.29
Carbonate Content Range (Maceral-Free Basis)	*Volume %*	0.00-36.84	3.17-54.55
Sulfide Content Range (Maceral-Free Basis)	*Volume %*	4.18-42.11	0.00-32.94
Gross Calorific Value Range (Moist, Mineral-Matter-Free)	*Btu/lb*	14,367-16,860	14,775-15,268
Fixed Carbon Range (Dry, Mineral-Matter-Free Basis)	*wt. %*	60.59-74.37	79.10-91.08
Apparent Coal Rank (ASTM Method D 388)		lvb	hvAb
Apparent Coal Rank Range (Mean Maximum Vitrinite Reflectance)		mvb-lvb	hvAb
Methane Storage Capacity[a]			
Methane Storage Capacity Range (Dry, Ash-Free Basis)	*scf/ton*	492.5	368.8-420.2
Methane Storage Capacity Range (In-Situ Basis)	*scf/ton*	410.4	260.2-382.7
Reservoir Properties			
No. of Reservoirs (coal, coaly shale, carbonaceous shale)		5	8
Effective Wet Reservoir Thickness	*feet*	6.4	8.8
Estimated Reservoir Temperature Range	*°F*	75-95	70-95
Estimated Pressure Gradient	*psi/ft*	0.400	0.400
Estimated Initial Reservoir Pressure Range	*psia*	285.9-805.9	843.7
Gas Content Range (Dry, Ash-Free Basis)	*scf/ton*	266.96-606.91	86.00-509.49
Gas Content Range (In-Situ Basis)	*scf/ton*	32.35-403.90	6.89-405.82
Diffusivity Range	sec^{-1}	1.36(09)-1.38(07)	4.17(08)-3.03(06)
Methane (CH_4) Concentration Range	*mole %*	96.20-97.63	90.03-97.94
Ethane (C_2H_6) Concentration Range	*mole %*	1.35-2.94	0.07-4.36
$C_{3\text{-}10}$ Concentration Range	*mole %*	0.05-0.14	0.00-0.34
Carbon Dioxide (CO_2) Concentration Range	*mole %*	0.04-0.71	0.12-0.87
Nitrogen (N_2) Concentration Range	*mole %*	0.00-0.41	1.77-5.30
Estimated Gas-In-Place Volume	*MMscf/160 acres*	427.89	530.00

[a]Calculated at estimated initial reservoir pressure.

formation (Fig. 4). The averaged results demonstrated that methane was the primary gas component in the specific samples (61–95%). However, other gas species were present in copious quantities; most notably, nitrogen (13–18%) in the upper and lower Cherokee Group coals of the Forest City Basin, nitrogen (14%), carbon dioxide (6%), ethane (9%), and C_{3-8} hydrocarbons (10%) in the Marmaton Group coals of the Cherokee Basin, and ethane (6%) in the Hartshorne Formation coals of the Arkoma Basin. Figure 4 data are simplified as the distribution of sorbed gas composition in individual reservoirs, which can vary dramatically over relative short stratigraphic intervals, is not apparent.

TABLE 10.—Reservoir Properties for Arkoma Basin Hartshorne Formation Coal

Parameter	Units	Value	
Well		CH # 2-16	CH # 1-21
Sampling Statistics			
Top of Sampled Interval	*feet*	2,356.8	2,449.5
Bottom of Sampled Interval	*feet*	2,401.1	2,457.8
Sampled Interval Thickness	*feet*	44.3	8.3
Number of Desorption Samples		6	8
Coal Properties			
Grain Density Range (In-Situ Basis)	*g/cm^3*	1.41-2.65	1.34-2.65
Ash Content Range (In-Situ Basis)	*wt. %*	07.03-90.31	06.69-88.73
Moisture Holding Capacity Range	*wt. %*	01.68-07.72	00.69-02.81
Sulfur Content Range (In-Situ Basis)	*wt. %*	00.07-00.88	00.05-09.27
Maximum Vitrinite Reflectance Range	*%*	2.03-2.30	1.29-1.38
Vitrinite Content (Mineral-Matter-Free Basis)	*Volume %*	86.75	87.28
Inertinite Content (Mineral-Matter-Free Basis)	*Volume %*	13.25	12.72
Liptinite Content (Mineral-Matter-Free Basis)	*Volume %*	0.00	0.00
Clay Content (Maceral-Free Basis)	*Volume %*	59.38	58.33
Quartz Content (Maceral-Free Basis)	*Volume %*	0.00	38.89
Carbonate Content (Maceral-Free Basis)	*Volume %*	31.25	2.78
Sulfide Content (Maceral-Free Basis)	*Volume %*	9.38	0.00
Gross Calorific Value (Moist, Mineral-Matter-Free Basis)	*Btu/lb*	15,506	15,427
Fixed Carbon (Dry, Mineral-Matter-Free Basis)	*wt. %*	86.92	87.90
Apparent Coal Rank (ASTM Method D 388)		sa	mvb
Apparent Coal Rank Range (Mean Maximum Vitrinite Reflectance)		lvb –sa	mvb
Methane Storage Capacity[a]			
Methane Storage Capacity Range (Dry, Ash-Free Basis)	*scf/ton*	791.6	535.5
Methane Storage Capacity Range (In-Situ Basis)	*scf/ton*	649.8	345.6
Reservoir Properties			
No. of Reservoirs (coal, coaly shale, carbonaceous shale)		2	1
Effective Wet Reservoir Thickness	*feet*	6.0	7.8
Estimated Reservoir Temperature Range	*°F*	95-100	100
Estimated Pressure Gradient	*psi/ft*	0.400	0.400
Estimated Initial Reservoir Pressure Range	*psia*	0.400	0.400
Gas Content Range (Dry, Ash-Free Basis)	*scf/ton*	265.54-742.36	164.08-314.26
Gas Content Range (In-Situ Basis)	*scf/ton*	21.58-678.39	20.19-288.93
Diffusivity Range	*sec^{-1}*	7.88(08)-2.28(06)	6.23(07)-3.07(06)
Methane (CH_4) Concentration	*mole %*	97.04	87.97
Ethane (C_2H_6) Concentration	*mole %*	1.87	9.49
$C_{3\text{-}10}$ Concentration	*mole %*	0.08	1.66
Carbon Dioxide (CO_2) Concentration	*mole %*	0.66	0.40
Nitrogen (N_2) Concentration	*mole %*	0.35	0.43
Estimated Gas-In-Place Volume	*MMscf/160 acres*	801.89	1,224.82

[a]Calculated at estimated initial reservoir pressure.

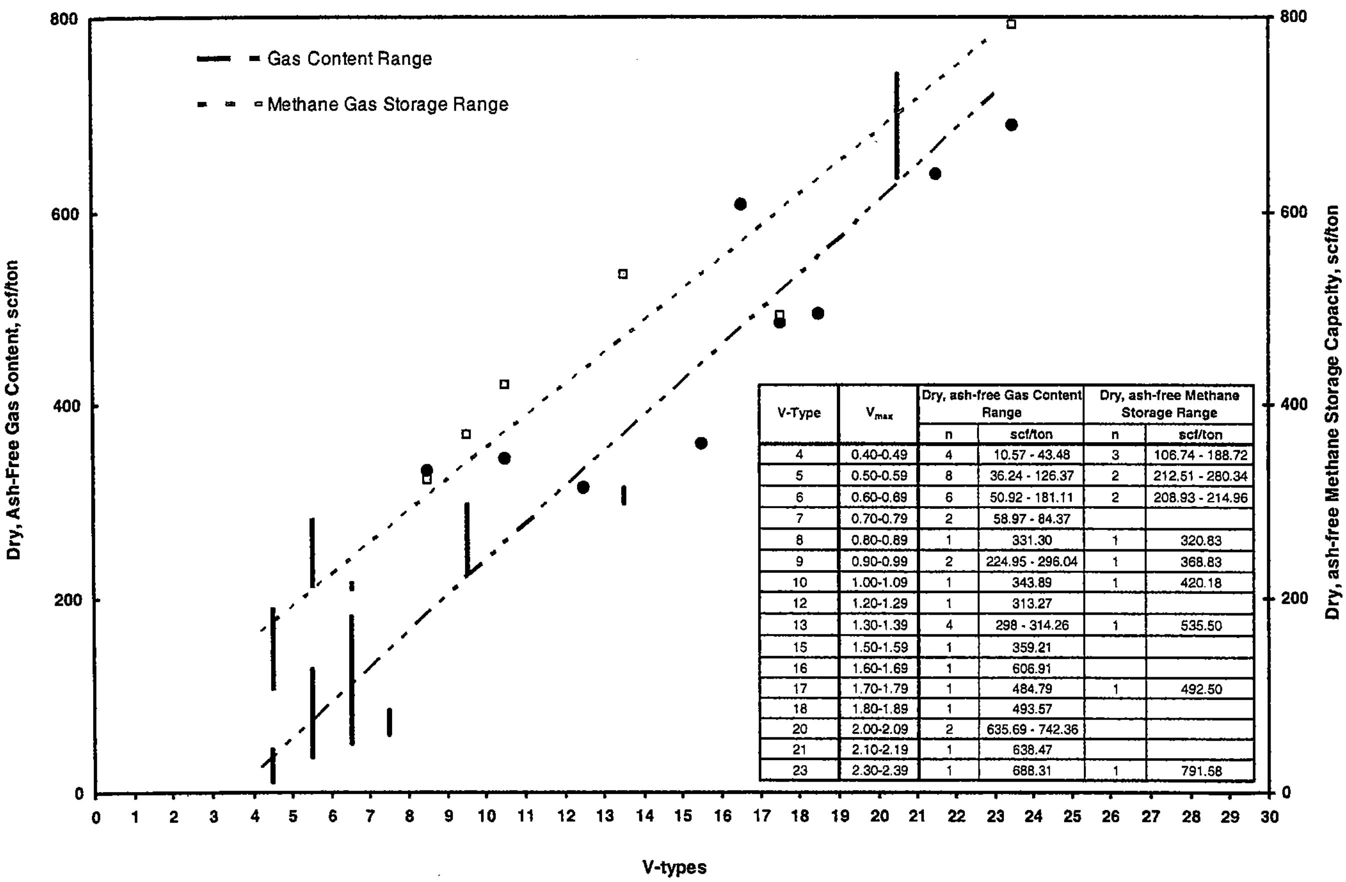
Diffusivity

The rate at which gas diffuses through the coal matrix is commonly expressed in terms of sorption time, which is the amount of time required to desorb 63% of the total gas content if the samples are maintained at constant temperature (Mavor and Nelson, 1997). Diffusivity has little impact upon gas production rates, which are more strongly controlled by reservoir pressure and permeability.

Gas diffusion in coal gas reservoirs is considered fast when sorption times are less than 50 hours. Fast sorption time is commonly observed in samples from the San Juan Basin Fruitland (Mavor and Nelson, 1997) and

TABLE 11.—Coalbed Geometry and Gas-In-Place Volume Estimates for the Forest City, Cherokee, and Arkoma Basins

	Forest City Basin				Cherokee Basin	Arkoma Basin			
Parameters (units)	CH #1	CH #2	CH #3	CH #4	CW #1	CH #2-16	CH #2-16	CH #1-21	CH #1-21
Group/formation:	L. Cherokee	L. Cherokee	L. Cherokee	L. Cherokee	Cherokee	McAlester	Hartshorne	McAlester	Hartshorne
Top depth (ft):	861.7	1,268.1	1,612.7	1,980.0	688.1	678.4	2,356.8	831.0	2,449.5
Bottom depth (ft):	1,134.2	1,652.0	1,756.8	2,257.8	1,070.3	1,978.4	2,401.1	2,073.1	2,457.8
Sampled interval thickness (ft):	272.5	383.9	144.1	277.8	382.2	1,300.0	44.3	1,242.1	8.3
Number of reservoirs:	11	11	9	13	13	5	2	8	1
Effective net thickness (ft):	16.4	19.9	17.5	21.3	14.3	6.4	6.0	8.8	7.8
Gas-in-place per area (MMscf/160 acres):	310.30	160.60	390.30	336.29	623.10	427.89	801.89	530.00	1,224.82



V-Type	V_{max}	Dry, ash-free Gas Content Range		Dry, ash-free Methane Storage Range	
		n	scf/ton	n	scf/ton
4	0.40-0.49	4	10.57 - 43.48	3	106.74 - 188.72
5	0.50-0.59	8	36.24 - 126.37	2	212.51 - 280.34
6	0.60-0.69	6	50.92 - 181.11	2	208.93 - 214.96
7	0.70-0.79	2	58.97 - 84.37		
8	0.80-0.89	1	331.30	1	320.83
9	0.90-0.99	2	224.95 - 296.04	1	368.83
10	1.00-1.09	1	343.89	1	420.18
12	1.20-1.29	1	313.27		
13	1.30-1.39	4	298 - 314.26	1	535.50
15	1.50-1.59	1	359.21		
16	1.60-1.69	1	606.91		
17	1.70-1.79	1	484.79	1	492.50
18	1.80-1.89	1	493.57		
20	2.00-2.09	2	635.69 - 742.36		
21	2.10-2.19	1	638.47		
23	2.30-2.39	1	688.31	1	791.58

Figure 3. Dry, ash-free gas content and methane storage capacity vs. vitrinite reflectance types (V-types). Abbreviations: scf/ton = standard cubic feet per ton; n = sample size.

from the Powder River Basin Fort Union (Pratt and others, 1999) coal seams. Diffusion rates of this order are not believed to be documented for eastern and Midcontinent United States coal gas reservoirs. Furthermore, the rate of gas diffusion of Carboniferous coal gas reservoirs located in eastern and Midcontinent coal basins on the whole is typically much slower than that encountered in Cretaceous and Tertiary coal gas reser-

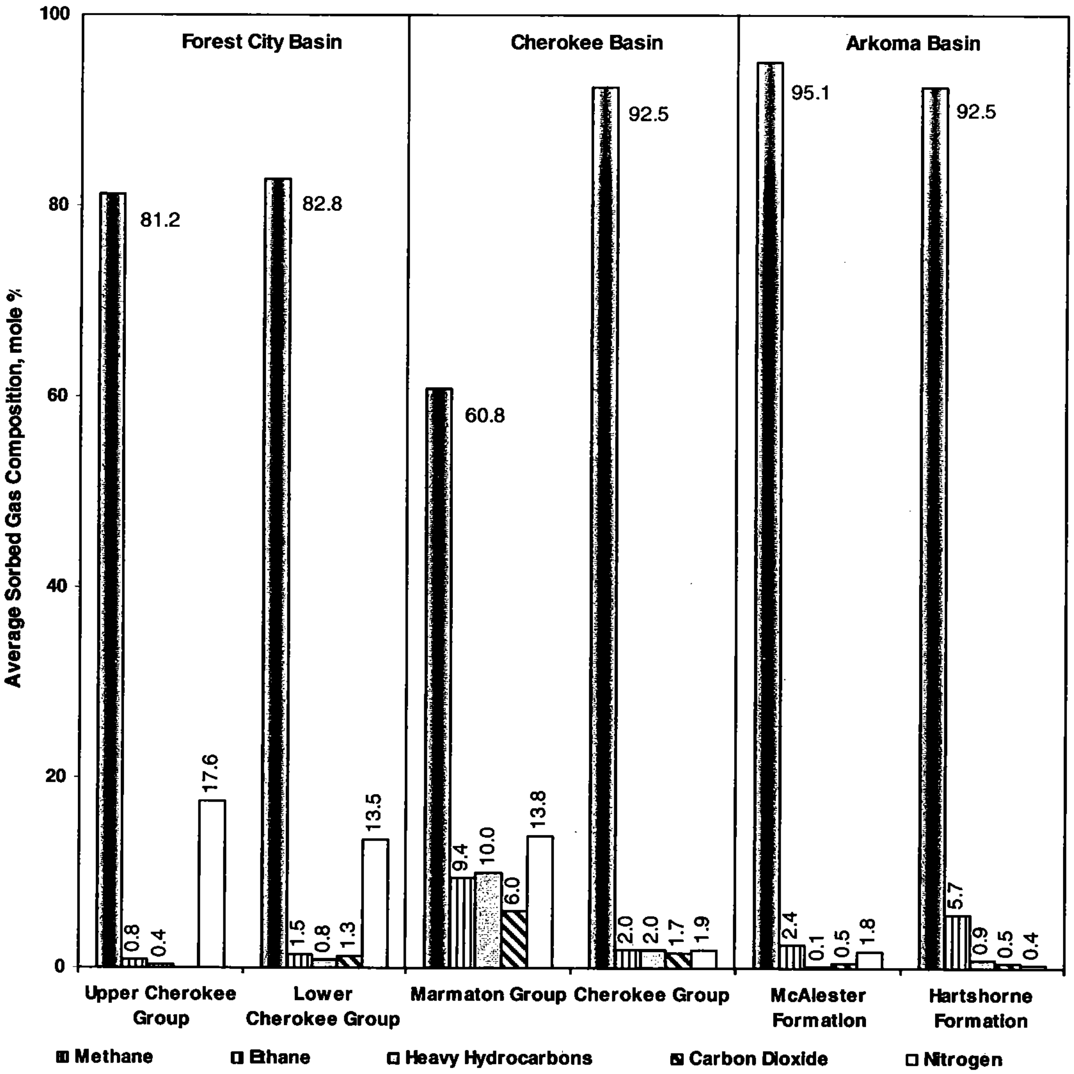


Figure 4. Histograms of averaged sorbed phase gas composition for sampled wells in study.

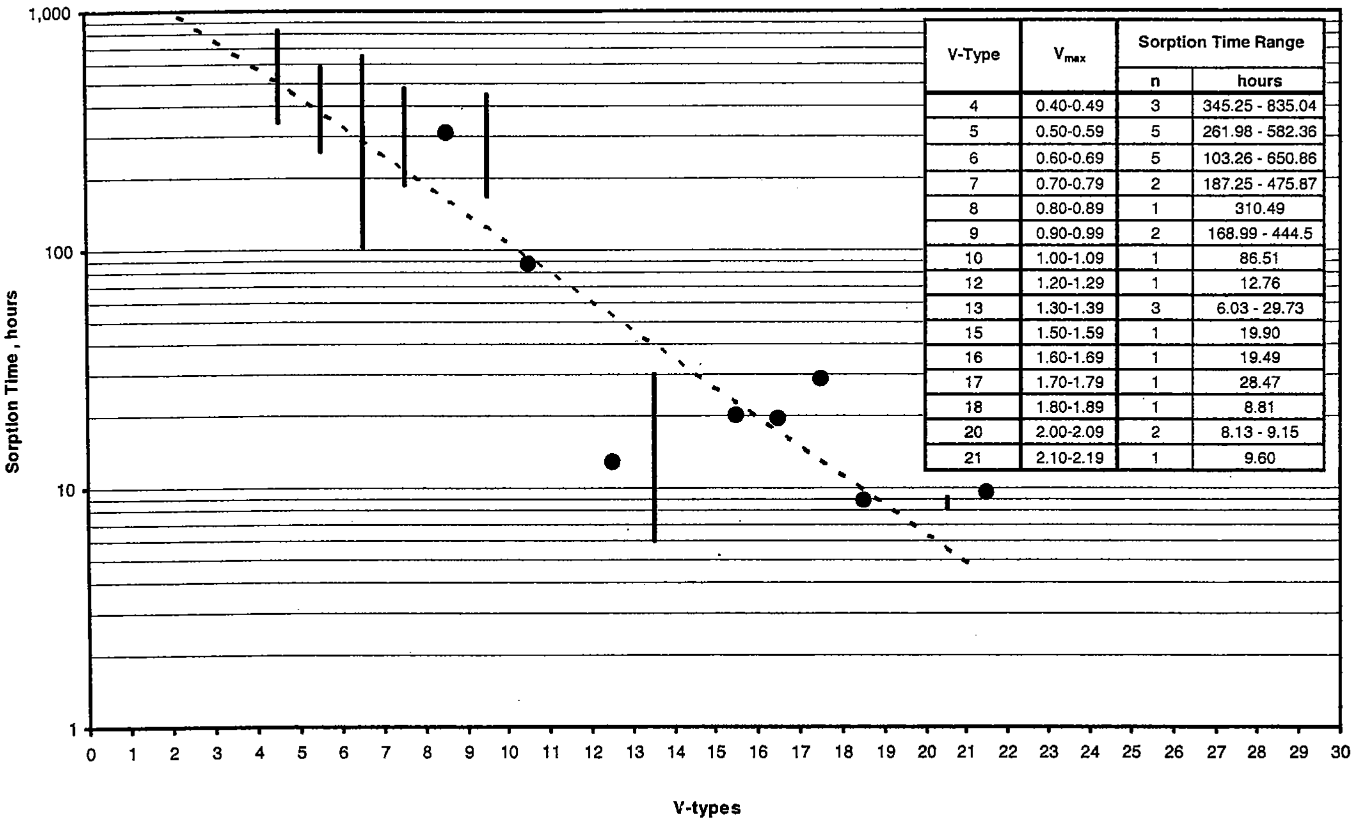
voirs in western United States coal basins. This apparent phenomenon is likely caused by a fundamental difference between Carboniferous and Cretaceous/ Tertiary coal matrix structures at the molecular level, and perhaps most importantly by the size distribution and geometry of primary porosity (micro-, meso- and macropores).

Sorption times for 30 desorption samples on which thermal maturity data were acquired were evaluated across the region. When sorption time was graphed on a logarithmic scale, it was indirectly proportional to the maximum vitrinite reflectance (i.e., thermal maturity) of the coal (Fig. 5). Sorption times varied between 8 and 835 hours across the WIC Region. The fastest sorption times (8–28 hours) were measured in low volatile bituminous and semi-anthracite coals in the Arkoma Basin. The slowest sorption times were measured in subbituminous–high volatile B bituminous samples in the Forest City Basin.

It is apparent from the relationship that significant sorption time variation exists within a given V-Type, especially at maximum vitrinite reflectance values <1.00%. This disparity is caused by compositional inconsistencies between samples. For example, samples that had the highest concentrations of mineral matter and/or inertinite group macerals had much faster desorption rates than vitrinite-rich coal samples that contained little inorganic material. Sorption time values would have been more in line with the highest values of Figure 5 had the evaluation been constrained to clean coal intervals with "average" inertinite content.

Methane-Storage Capacity

The gas storage capacity at any given pressure is calculated from laboratory adsorption isotherm data and is reported at the initial reservoir pressure. Unfortunately, reservoir pressures were not measured as part of this study. A pressure gradient of 0.4 psi/ft, which has been observed in some areas of the WIC Region, was assumed to estimate the initial reservoir pressures at



V-Type	V_{max}	Sorption Time Range	
		n	hours
4	0.40-0.49	3	345.25 - 835.04
5	0.50-0.59	5	261.98 - 582.36
6	0.60-0.69	5	103.26 - 650.86
7	0.70-0.79	2	187.25 - 475.87
8	0.80-0.89	1	310.49
9	0.90-0.99	2	168.99 - 444.5
10	1.00-1.09	1	86.51
12	1.20-1.29	1	12.76
13	1.30-1.39	3	6.03 - 29.73
15	1.50-1.59	1	19.90
16	1.60-1.69	1	19.49
17	1.70-1.79	1	28.47
18	1.80-1.89	1	8.81
20	2.00-2.09	2	8.13 - 9.15
21	2.10-2.19	1	9.60

Figure 5. Sorption time (in hours) plotted against vitrinite reflectance types (V-types).

each core hole location. Reliance on this estimation undermines the critical importance of gathering accurate pressure data, but provides consistency for comparison of gas storage capacity estimates between reservoirs in the WIC Region.

Methane adsorption isotherm experiments were performed on 20 desorption samples collected in the Cherokee Group of the Forest City and Cherokee Basins and in the McAlester and Hartshorne Formations of the Arkoma Basin. At estimated reservoir pressures, methane storage capacity estimates were directly proportional to the maximum vitrinite reflectance (i.e., thermal maturity) measured on isotherm samples (Fig. 3). This relationship is noteworthy, but should not be routinely used to predict gas storage capacity because the data indicates that methane storage capacities can vary significantly for a given coal rank.

If the assumed 0.40 psi/ft pressure gradient at the core hole locations is similar to reality, then the relationships illustrated in Figure 3 suggest that very few of the WIC Region reservoirs are at or near gas saturated conditions. Undersaturation can significantly hinder gas productivity. However, it is recognized that some WIC Region reservoirs are at or near gas saturation. Several data points in Figure 3, ranging from V-Type 6 through V-Type 20, support this fact, which suggests that gas saturated conditions are not a function of thermal maturity.

The data presented in Figure 4 demonstrate that methane is not the only gas present in reservoirs. Significant quantities of nitrogen (13–18%) were measured in the upper and lower Cherokee Group samples taken in the Forest City Basin. The gas storage capacity results in Figure 3 would be lower had it honored the presence of nitrogen, which in turn, would increase the gas saturation level. The opposite correction would apply in the case of the Hartshorne coal, where a relatively significant quantity of ethane (~6%) could be present in the reservoir in some areas of the basin.

POTENTIAL GAS-PRODUCTIVITY ESTIMATES

To estimate the potential gas productivity of a reservoir requires the data summarized in the preceding section and reservoir pressure data, as well as data concerning the absolute and relative permeability of the coal natural fracture systems. Absolute permeability estimates are generally obtained from well tests. Relative permeability estimates are obtained by laboratory measurements performed on whole core samples. Unfortunately, pressure and permeability data were not collected as part of this project.

Because of the lack of permeability information, we took another approach to make a first-pass estimate of the potential ranges of gas productivity that may be possible at the research well locations. Based upon our experience with coal permeability ranges in many basins, we estimated potential log-normal permeability distributions that may be present. We relied upon coal-relative permeability data reported in the literature

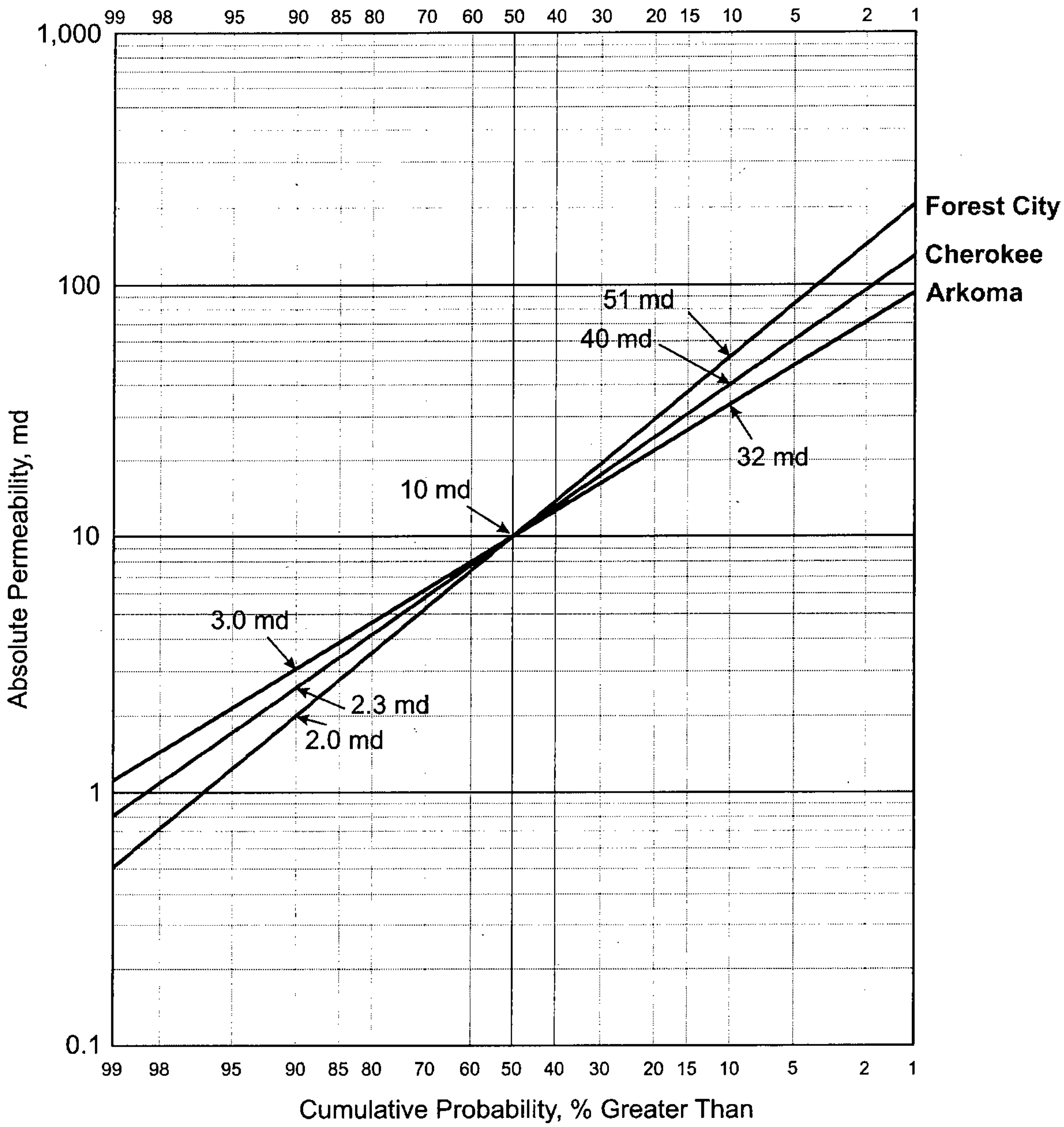


Figure 6. Estimated log-normal absolute permeability (in millidarcies, md) distributions for the Western Interior Coal Region.

from the San Juan Basin, Fruitland Formation. The permeability estimates were used to create reservoir simulation models incorporating the data summarized in the preceding section. The simulation models were used to forecast gas productivity as a function of time.

Figure 6 illustrates log-normal absolute permeability distributions that we believe to be appropriate for the WIC Region. Each distribution has a 50% probability of an absolute permeability of 10 md or greater. For the Forest City, Cherokee, and Arkoma Basins, there is a 90% probability that the absolute permeability is greater than 2, 2.3, and 3 md, respectively. There is a 10% probability that the permeability exceeds 51, 40, and 32 md for the three respective basins. As relative permeability data were unavailable, we relied upon the data presented for the San Juan Basin, Fruitland Formation (Gash and others, 1993). We have found these data to be applicable in the Cherokee Basin and they may be applicable in the other Midcontinent basins. Coal natural fracture porosity also has a substantial impact upon water production rates. Greater porosity results in greater water production and lower gas production. We used a relatively high natural fracture porosity estimate of 0.5% for our projections.

The reservoir simulation models honored the gas content and depth information with gas-in-place estimates similar to those summarized in the reservoir property tables. These models were used to forecast the possible gas productivity of a production hole drilled at

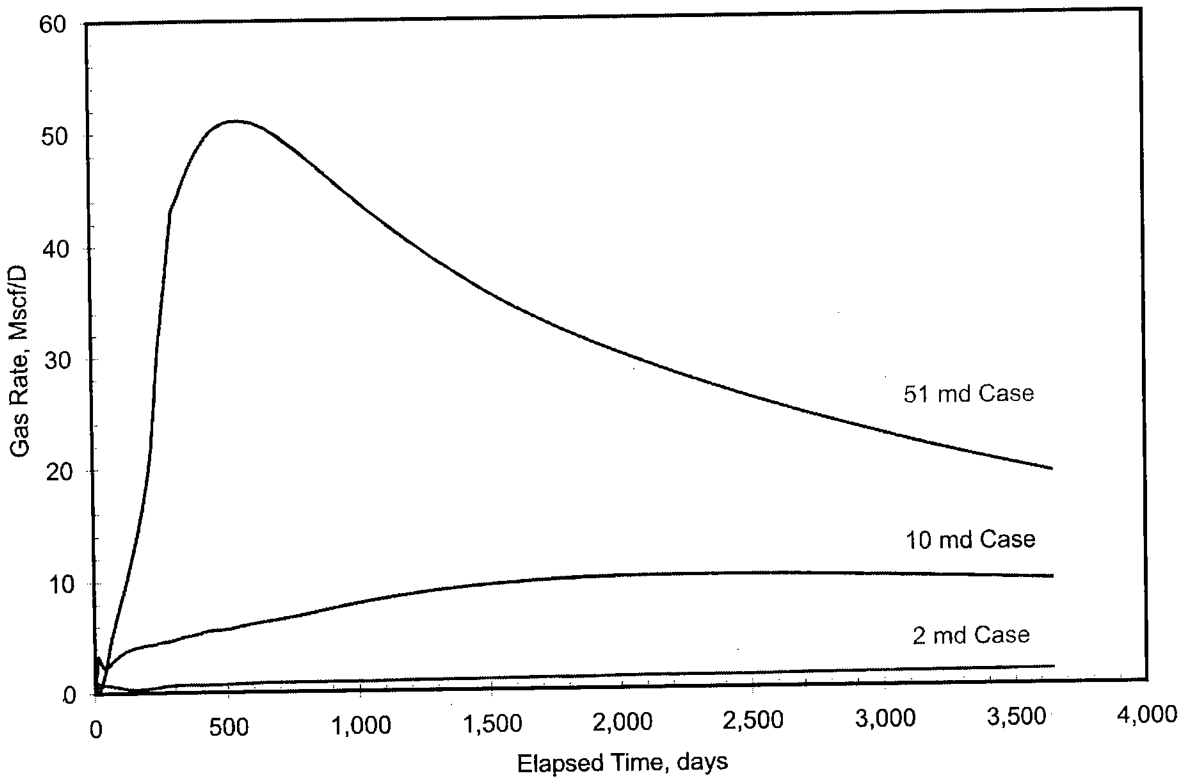


Figure 7. Forest City Basin CH #1 potential lower Cherokee gas productivity. Gas rate given in thousand standard cubic feet per darcy (Mscf/D) plotted against elapsed time (in days) for three cases (in millidarcies, md).

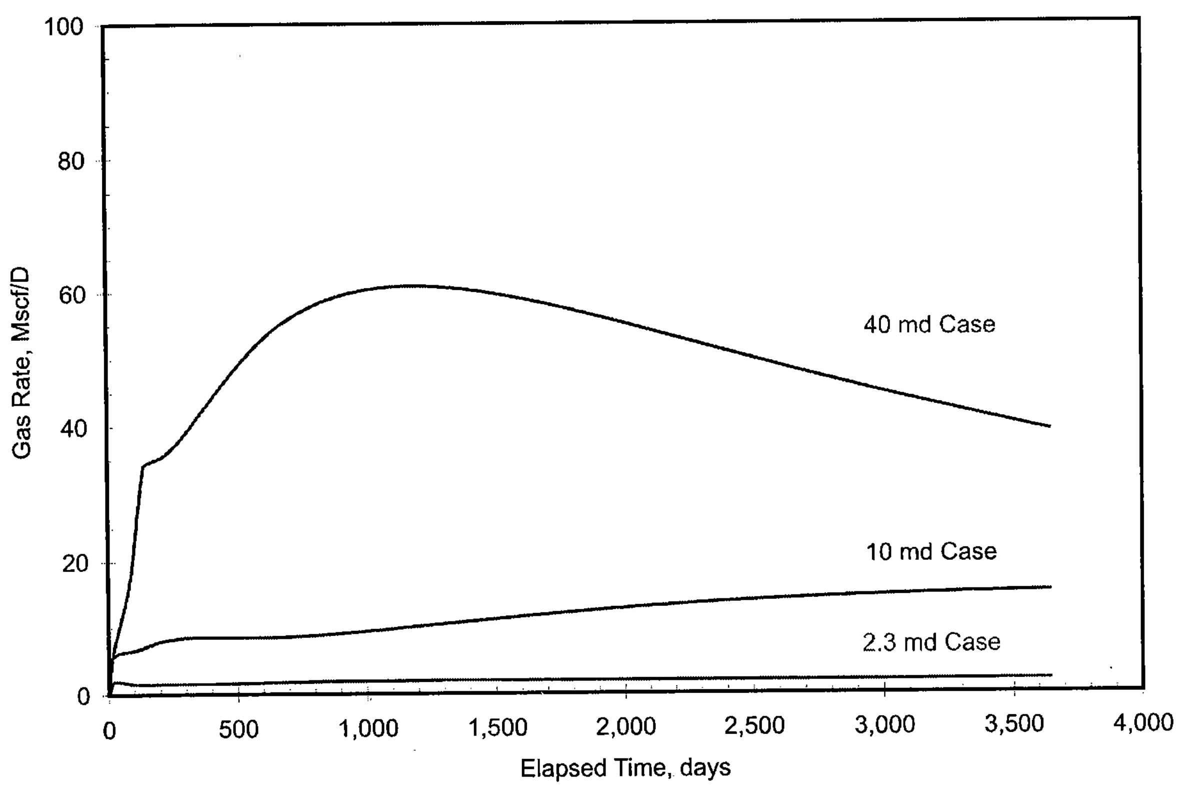


Figure 8. Cherokee Basin CW #1 potential lower Cherokee gas productivity. Gas rate given in thousand standard cubic feet per darcy (Mscf/D) plotted against elapsed time (in days) for three cases (in millidarcies, md).

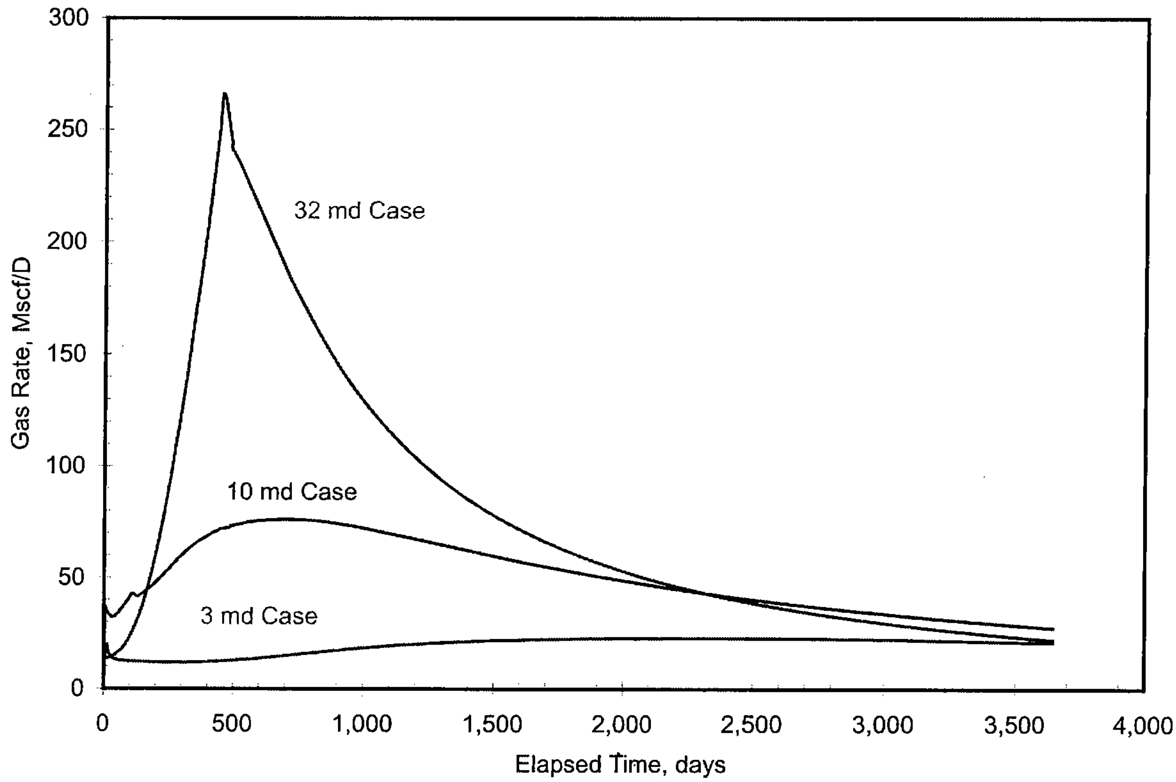


Figure 9. Arkoma Basin CH #1-21 potential Hartshorne gas productivity. Gas rate given in thousand standard cubic feet per darcy (Mscf/D) plotted against elapsed time (in days) for three cases (in millidarcies, md).

each of the cooperative research well locations. Figures 7–9 illustrate the estimated productivity of the lower Cherokee gas-bearing intervals penetrated by the Forest City Basin CH #1, the lower Cherokee intervals penetrated by the Cherokee Basin CW #1, and the Hartshorne coal penetrated by the Arkoma Basin CH #1-21 well.

The peak gas production rates for each of the three Forest City permeability levels were 1.3, 10.1, and 51.1 Mscf/D (thousand standard cubic feet per darcy) for the 2, 10, and 51 md (millidarcies) cases, respectively (Fig. 7). The cumulative gas production after 10 years was estimated to be 4, 31, and 110 MMscf (million standard cubic feet) for the same three permeability cases, corresponding to recovery of 1, 10, and 37% of the original gas-in-place volume. Only the 51 md case had a chance of meeting today's economic requirements.

The peak gas production rates for each of the three Cherokee Basin permeability levels were 2, 15, and 61 Mscf/D for the 2.3, 10, and 40 md cases, respectively (Fig. 8). The cumulative gas production after 10 years was estimated to be 7, 43, and 182 MMscf for the same three permeability cases corresponding to recovery of 1, 7, and 29% of the original gas-in-place volume. Only the 40 md case had a chance of meeting today's economic requirements.

The peak gas production rates for each of the three Arkoma Basin Hartshorne permeability levels were 23, 76, and 266 Mscf/D for the 3, 10, and 32 md cases, respectively (Fig. 9). The cumulative gas production after ten years was estimated to be 70, 180, and 280 MMscf for the same three permeability cases corresponding to recovery of 17, 44, and 67% of the original gas-in-place volume. The 10 and 32 md cases had a chance of meeting today's economic requirements.

Compared with the Arkoma Hartshorne projections, the relatively low productivity of the Forest City and Cherokee Basin projections was due to relatively low gas contents, most of which are significantly lower than the gas-storage capacities. The Arkoma Hartshorne projections were made for relatively high gas contents that were nearer to the gas storage capacities.

The seven cooperative wells sampled a very limited portion of a very large area. The productivity projections should not be applied to any of the coal basins as a whole. Actual productivity is likely to differ significantly.

CONCLUSIONS

The WIC Region has experienced enormous growth in coalbed methane exploration and production during the past several years but remains largely unexplored. Many operators are drilling wells indiscriminately with little information concerning the gas resource and production potential. Critical exploration and development decision-making would be improved if operators gained a better understanding of reservoir properties, and how they vary across the WIC Region.

This study demonstrates that coal rank is an important factor to consider when exploring for coal gas in the WIC Region. Assuming all other parameters are equal, the ability of a coal to generate and store gas increases as the coal rank (i.e., thermal maturity) increases during the coalification process. The ability to use coal rank during exploration is not a new concept. This rather simple rationale was utilized to explore and develop coal-gas wells in the San Juan and Black Warrior Basins in the 1980s and early 1990s, where coals of high volatile and medium volatile bituminous rank were targeted.

Although this paper demonstrates that gas content, storage capacity and diffusion rates can be directly related to coal rank for coals of similar age and depositional history over a large geographic area, it also demonstrates that gas content and storage capacity can vary widely between reservoirs of a given rank. In short, many conditions in addition to coal rank and sorption properties must be considered before a reasonable understanding of commercial development potential can be assumed.

In the middle and late 1990s, the economic viability of gas production from shallow, low rank (subbituminous) Tertiary coals was demonstrated in the Powder River Basin. More recently, commercial gas production has been established in shallow, thin, low rank Horseshoe Canyon coals in the Sedimentary Basin of the eastern Alberta Plains. These discoveries, along with a sustained increase in gas prices, have undoubtedly given rise to increased interest in low rank coal gas exploration in the United States and many other parts of the world. However, it is critically important to consider the reasons why these coal gas plays have been successful before investing a large amount of capital and resources into coal gas exploration. Parameters including coal seam thickness and lateral continuity; absolute permeability; initial reservoir pressure and gas saturation; the effect of nearby surface mines; well drainage and development patterns; formation water quality; access to infrastructure; and inexpensive exploration, drilling, and completion costs were all critical factors partly responsible for the success initially established in the Powder River Basin. Less information is available for the Horseshoe Canyon play, but it is generally known that conventional sandstone reservoirs are adjacent to the targeted coal seams and that there is little to no water contained in the natural-fracture systems in areas that have achieved commercial success.

To accurately predict gas productivity requires both reservoir pressure and permeability data. To obtain this data, operators should routinely conduct well tests on potentially productive intervals whenever reservoir pressure and permeability are not known with reasonable confidence. Proper identification of commercial permeability and pressure levels will result in reduced completion costs, as non-commercial intervals will not be completed or stimulated.

ACKNOWLEDGMENTS

Funding for this project was provided by the Exploration and Production Department of the Gas Research Institute (GRI). Robert W. Siegfried II provided the project management and guidance for this project on behalf of GRI. This project required the advice, cooperation, and assistance from El Paso and Colt Energy. Curtis Matthews and Paul Basinski directed the work for the six El Paso core holes, and Nick Powell directed the work for the Colt Energy core hole. The TICORA Geosciences, Inc., project team that worked on this project included numerous staff members from the Field, Lab, and Consulting Departments. The diligence and effort by the entire Field and Lab Departments involved with this project, most notably Randy Laney, Will Drexler, Mike Watt, and Chad Hartman is sincerely appreciated. Members of the Consulting Department, who integrated and interpreted a vast volume of raw data and summarized the WIC Region geology, included Simon Testa, Luis Baez, Tracy Lombardi, Will Drexler, and Chris Hoffman. Simon Testa, who presented this work upon a "last-minute" request at the Unconventional Energy Resources in the Southern Midcontinent conference, March 9–10, 2004, deserves special acknowledgement. Finally, the research and editing efforts provided by Luis Baez, Simon Testa and Dave Young, which were critical to getting this paper completed, are greatly appreciated.

REFERENCES CITED

ASTM, 1997, Designation D388-95 Standard Classification of Coals by Rank: American Society for Testing and Materials, West Conshohocken, Pennsylvania, Annual Book of ASTM Standards, Gaseous Fuels; Coal and Coke, v. 5.05, p. 168–171.

Cardott, B. J., 2005, Coalbed-methane activity in Oklahoma, 2004 update, *in* Cardott, B. J. (ed.), Unconventional energy resources in the southern Midcontinent, 2004 symposium: Oklahoma Geological Survey Circular 110 [this volume], p. 69–81.

Gash, B. W.; Volz, R. F.; Potter, G.; and Corgan, J. M., 1993, The effects of cleat orientation and confining pressure on cleat porosity, permeability, and relative permeability in coal: University of Alabama, Tuscaloosa, Proceedings of the 1993 Coalbed Methane Symposium, Paper 9321, p. 247–255.

Mavor, M. J.; and Nelson, C. R., 1997, Coalbed reservoir gas-in-place analysis: Gas Research Institute, Chicago, Report No. GRI-97/0263, 121 p.

Mavor, M. J.; Hartman, C.; and Pratt, T. J., 2004, Uncertainty in sorption isotherm measurements: University of Alabama, Tuscaloosa, Proceedings of the 2004 International Coalbed Methane Symposium, Paper 411, 14 p.

McLennan, J. D.; Schafer, P. S.; and Pratt, T. J., 1995, A guide to determining coal gas content: Gas Research Institute, Chicago, Report No. GRI-94/0396, 193 p.

Newell, K. D.; Johnson, T. A.; Brown, W. M.; Lange, J. P.; and Carr, T. R., 2004, Geological and geochemical factors influencing the emerging coalbed gas play in the Cherokee and Forest City Basins in eastern Kansas: Kansas Geological Survey Open-File Report 2004-17, 1 p. (Poster available at: http://www.kgs.ku.edu/PRS/publication/2004/AAPG/Coalbed/P1-02.html).

North American Coalbed Methane Resource Map, 2001, Gas Technology Institute, Report No. GTI 01/0165, Des Plaines, Illinois, 1 p. (Map available at: http://www.

gastechnology.org/webroot/app/xn/xd.aspx?xd=10AbstractPage\12998.xml.)

Pratt, T. J.; and Baez, L. R. G., 2003, Critical data requirements for coal and gas shale resource assessment: University of Alabama, Tuscaloosa, Proceedings of the 2003 International Coal Methane Symposium, Paper 367, 22 p.

Pratt, T. J.; and Testa, S. M., 2003, Sample preparation for coal and shale gas resource assessment: University of Alabama, Tuscaloosa, Proceedings of the 2003 International Coal Methane Symposium, Paper 356, 13 p.

Pratt, T. J.; Mavor, M. J.; and DeBruyn, R. P., 1999, Coal gas resource and production potential of subbituminous coal in the Powder River Basin: Gillette, Wyoming, Society of Petroleum Engineers, Rocky Mountain Regional Meeting, SPE Paper 559.

Coalbed-Methane Potential in Osage County, Oklahoma

John F. Sinclair
AMVEST Oil and Gas
Charlottesville, Virginia

ABSTRACT.—Middle Pennsylvanian host rocks containing numerous thin coal seams are present within Osage County, Oklahoma. The Rowe, Bluejacket, Weir-Pittsburg, and Dawson coals are the primary seams for coalbed-methane (CBM) exploration and development. These seams are extremely thin as aggregate and as individual seams when compared with other CBM plays outside of the Midcontinent area. Where present, these seams range from a few inches to 5 ft thick. The average individual seam thickness is less than 2 ft. It is rare for more than 12 net feet of coal to be present within a single well bore. These coals are high-volatile A to medium-volatile bituminous in rank. Vitrinite reflectance values range from 0.85% to 1.1% and generally increase with depth.

Structurally, Osage County is located within the northeast Oklahoma shelf. General dip is to the west, but numerous domes and northeast–southwest-trending anticlines are located in Osage County. Basement faulting is the primary mechanism for creating structural disturbance, and many of these faults appear to be compressional features derived from movement originating in the Arkoma Basin.

AMVEST Osage has drilled 140 CBM wells since January 2000. Production started in September 2000, and current production as of December 1, 2003, was 8.3 million cubic feet of gas per day. In addition to the drilled wells, 5 slim-hole, continuous, wireline retrievable cores were drilled. The cores were used to evaluate the CBM resource through gas content measurements, adsorption isotherms, and maceral analysis. Total resource calculated for the AMVEST concession in Osage County is in excess of 2.1 trillion cubic feet. Numerous permeability measurements have been made within the coal seams of Osage County within cased wells and in the open-hole–core well bores. Permeability ranges from 0.2 md to >300 md.

Initial exploration focused on thicker coal accumulations on structural highs or noses of anticlines to find higher permeability within the coals. This approach was not always successful, and not all of the good producing wells are located on these structural highs. Currently, AMVEST is developing a structural model that will help predict areas of higher permeability.

Sinclair, J. F., 2005, Coalbed-methane potential in Osage County, Oklahoma, *in* Cardott, B. J. (ed.), Unconventional energy resources in the southern Midcontinent, 2004 symposium: Oklahoma Geological Survey Circular 110, p. 105.

Coalbed Methane: What Makes for Economic Success in the Arkoma Basin—Methods and Economics

John H. Wendell, Jr.
Wendell Consulting, LLC
Fort Worth, Texas

ABSTRACT.—Generally, production of coalbed methane (CBM) is a high-density, high-intensity endeavor, which must have extensive cost containment to insure economic success. Conventional oil and gas drilling and production mentality must be revamped to simplify and, in some cases, be down-engineered to achieve optimized results. Streamlined activities must begin with sizing ingress and drilling footprint and using efficient drilling methods.

Only basic logs are run, and cementing procedures are designed that provide adequate results and may be accomplished by smaller, low-cost, independent service companies. Stimulation programs are designed to achieve maximum recovery and lowest cost. Again, smaller, independent service companies can be trained and equipped to provide excellent fracs at much lower costs than the big three.

Project sizing is important. A critical mass must be achieved for both operational and economic purposes. The endeavor must be large enough to support self-operated service equipment such as pulling units and produced-water disposal. Timely data capture is essential to evaluate costs and results and to quickly identify well problems and put wells back to maximum production on a timely manner.

Economic analysis is ultimately important to ascertain what type of well to drill (horizontal or vertical) to optimize financial goals.

INTRODUCTION

The salient question is: *What makes Coalbed Methane (CBM) profitable?* Although the final answers appear simple, the path to achieve a favorable outcome may not be as easy as it appears from the most elegant solutions.

Production of CBM in the Arkoma Basin emanates from a large number of characteristically low-production wells that are relatively low cost to drill, complete, and produce. Expected peak production rates for individual wells vary from 10 to >250 thousand cubic feet of gas per day (Mcfd) from properly stimulated wells. The values depicted in this paper are derived from a representative assemblage of 152 wells that have been drilled, stimulated, and produced under my engineering during the past 10-year period. These wells were selected as having sufficient production history to reasonably predict demonstrated values of Expected Ultimate Recovery (EUR), production profile (dewatering time, peak rates, declines, etc.), operational costs, and infrastructure requirements.

Expected median peak rates of 45 Mcfd after 13 months of dewatering in low permeability areas with EURs of 110 million cubic feet (MMcf) were evaluated from 51 wells that were grouped in the areas that exhibited lower average response. Conversely, the production and reserve values from the 101 wells producing from the better-permeability coal locations regressed into an average well with an EUR of 320 MMcf with an average peak rate of 123 Mcfd that occurred during the 18th month of dewatering.

Operational costs were minimized with average Lease Operating Expenses (LOEs) being approximately $650 per well per month. Minimalist approach to site preparation, drilling, logging, testing, completing, stimulating, equipping, and producing the wells was paramount. When a well is producing at a low rate, even moderate excursions in cost make significant impact on well economics. This effect is more easily masked in more expensive wells that are producing at higher rates. CBM economics are most favorable to companies that are large enough to provide the economic critical mass of wells necessary to accomplish effective dewatering of the reservoir and to be able to make purchases in large enough quantities to achieve economies of bulk discounts. The most profitable companies are large enough to have their own service rigs and must have their own water disposal wells or be able to inexpensively take care of the produced water.

Wendell, J. H., Jr., 2005, Coalbed methane: what makes for economic success in the Arkoma Basin—methods and economics, *in* Cardott, B. J. (ed.), Unconventional energy resources in the southern Midcontinent, 2004 symposium: Oklahoma Geological Survey Circular 110, p. 107–114.

Although much CBM development is thought to be on the "cutting edge" of today's technology, many of the methods that are most cost effective are resident in the knowledge base of a more primitive oil patch. The temptation to over-design the equipment or to use more exotic methods than needed must be avoided. Cost benefit and containment must be exercised continually. The average LOEs and overhead charges customarily allocated to each well by larger companies, which are dealing with single well costs and production that are orders of magnitude greater than CBM, would diminish the economic return for CBM wells to unacceptable levels. CBM operations are more effective with a hands-on operation with quick reaction time and minimalist corporate infrastructure.

CBM DRILLING AND COMPLETION METHODS

Coalbed-methane wells can be drilled and completed at reasonable costs if reasonable methods are used. The drilling units used in most CBM wells are largely self-contained mobile drilling rigs using air-drilling techniques. Drill sites need only be large enough to contain the drilling equipment and subsequently the frac tanks and pump trucks for stimulation. A cleared area of 150 ft by 150 ft is generally more than adequate. Preparation of the drill site may be minimized in most cases if drilling schedules coincide with expected dryer-weather seasons. With judicious planning and luck, the initial ingress to the well for drilling, completing, and stimulation may be accomplished on either unimproved ground or minimally prepared surfaces.

There is no need to build an all-weather road and location for wells that are drilled in the dry season. The requirement for building a road that is adequate to support drilling rigs and frac vans is dramatically more extensive than what will be necessary as the permanent road used to service and produce the well. If the construction of the road can possibly be avoided, then three savings are obtained. First is the original cost of the heavy-duty road and location. Second is the cost of dressing up the drill site. And third, repair of the road after the drilling rig, completion units/rigs, and frac vehicles have egressed. During daily production operations in wet conditions, road damage may be avoided by pumpers utilizing weatherized all-terrain vehicles (ATVs) to check and perform minor maintenance on the wells. The cost of the ATV vanishes very rapidly contrasted to the cost of frequent road repair and rebuilding or the accelerated deterioration of pickups.

Optimize the size and type of drilling unit used to drill the well. In most cases, the wells will be of similar depth. Most wells are relatively shallow, 700–1,700 ft deep. There is no need to pay for a rig capable of drilling a 5,000-ft well and then to subsequently be on location for logging, running range-3 casing, and then cementing. It is sufficient to have an air rig that is capable of only drilling up to the depth needed and not be capable of having a derrick tall enough to run long casing. Only use the drilling unit for drilling the well. It is far less expensive to use the smaller drilling unit with lower per foot charge.

Logging units utilizing their own portable mast are competitively priced. The logging suite is again minimal—only gamma ray, dual density, and caliper unless you really believe that the sand you encountered is really not tight or wet. Then add the resistivity log. Log quality from the independent logging companies in the Arkoma region is more than adequate for CBM evaluation. Costs from the independent run approximately 45–50% of that charged by the major logging companies. Also, the logs have been optimized for CBM by the independents and are tailored to Arkoma CBM-analysis requirements.

The company should own its own pulling unit that is capable of running at least range-2 casing to the depths of the wells drilled. Generally, the rig will run the casing and hang it off on the conductor pipe with a simple bolt on two-piece casing clamp ($25.00) and be on and off the location in approximately 4 hours.

Cementing is accomplished by one of the competent independent cementing companies. The method used is basic. Except in the deepest wells, the alternate casing program is used. With proper cement design, formation damage is avoided and casing/water zones are protected. The cement that I favor is simple. Hole preparation is paramount. First circulate hole clean with fresh water followed by at least 20 barrels of gelled water. Follow next with a polymer gel as generally used for fracing. This cleans the hole and begins to seal the coal and other thief zones. Use of lost-circulation materials such as cello flake and ground up bituminous coal is normally sufficient to finish sealing off the zones from cement intrusion. Lead cement is lightened with approximately 4% gel or other expander, again loaded with lost-circulation materials. Tail cement is run in a volume sufficient only to cover the highest zone to be perforated. It is customarily just class A or class H with 10% salt and lost-circulation materials. This simple method of cementing has proved very effective. The cost of these jobs is less than half that of the major cementing companies. Side-by-side testing with this method and companies using latex-treated poz-lightened slurries have shown better results from the less exotic mixture. The less-expensive slurries have minimized cement intrusion into the coals and loss into thief zones. Instances of cement fall back and failure to circulate have been virtually eliminated. This was not the case with the more expensive latex blend, with which cement fall back and poor bonding were observed. After the wells are perforated, the coals appear to be undamaged with no acid or other breakdown being necessary to enter the zone for either pump-in/falloff permeability testing or for frac treatments.

When the cement sets, the independent loggers again set up on the well with their own mast, run a cement-bond log with gamma ray, and then perforate the coal. The normal perforation schedule is 8 shots per foot using 23-gram shaped charges in a 3⅛-in. hollow steel carrier. Economies are achieved by allowing the logging unit to fit the well into their schedule on an as convenient basis. This has worked in all but a few exceptions and normally has been timely enough. Again costs are 35–40% of that charged by the major companies for the same services.

At the outset, fracs in the Arkoma Basin were performed by the big-three frac companies. In the later 1990s, the major frac companies virtually abandoned servicing the Arkoma Basin. Smaller independents upgraded their equipment and instrumentation and quickly filled the void. The price difference was dramatic then between what the larger companies charge and the cost of the independent. In the bulk of the cases, savings of 30–50% were achieved through use of the independent. The independents have continued to be competitive and current savings are in the range of $16,500 versus $30,000+ for a similar frac. Cooperation between the independents and producers has helped the small frac companies build equipment tailored to the simple and minimal requirements for a water-sand frac that is normally performed. Fewer units and smaller equipment are needed as pump plunger sizes are optimized for CBM work. More effective use of horsepower is accomplished as small-piston, high-pressure pumps are no longer run in unloaded conditions.

The most effective frac design for the majority of the CBM wells has been a simple water-sand frac with no gels, acids, foams, or any additives other than biocide. This technique is the least damaging when performed properly. The experience and skill required to accomplish this method is higher than when using gelled fluids and requires quick response and superior teamwork between the frac operator and the engineer directing the frac.

However, the usual is never totally usual. Coal is not homogeneous in character and stress. Variances in local stress, cleating/permeability, rock strength, natural fracturing, rubbelization/powdering, faulting, aquifer activity, coal fines, and multiple possibilities of mineralization directly affect the type of stimulation that may be performed and ultimately the producibility of the coal.

If the permeability of the coal is low, or if a region of extremely "tender" or rubbelized/powdered coal is encountered, something more involved such as a horizontal well may be more appropriate. Horizontal wells have been introduced, with good results, into areas where either unsuccessful or marginal vertical CBM wells were drilled.

Recent enhancements in fracing fluids have been found to be advantageous for use in vertical problem wells. Use of Visco Elastic Surfactants (VES) has been used to advantage in the Arkoma and other basins where normal water-sand fracs have been unsuccessful or ineffective. The VES fluid is either just used as a fines-control agent and dewatering aid when used in leaner concentrations or as a viscosity enhancing medium when applied in richer mixes. The VES fluid improves the initial dewatering of the coals and treats the coal surfaces to a hydrocarbon wet state. This is advantageous to both relative perm to gas and to sequestration of coal fines.

Some coals require a thickened spearhead of fluid to begin the fracture when near well bore torturosity is a problem. VES fluids run in concentrations of 10–15 pounds per 1,000 gallons are viscosified to an equivalent of 15–20 pounds, respectively, of guar-gelling action. However, the VES has appeared to break effectively and not cause perm reductions such as guar or other gelling agents. The main advantage to this is that in "tender" coals that easily shear, even at moderate fluid injection velocities, can be treated at reduced rates that are below the critical velocity where coal slurries are ripped from the frac channel and impede propagation of the fracture. In cases where the critical injection rate with water alone was in the low 20 barrel per minute range and almost no sand could be successfully carried, a VES concentration of 5–10 pounds per 1,000 gallons allowed the sand to be carried at excellent densities at 18 barrels per minute pumping rate without shearing the coal. Long-term response of this technique has not been established, but early indications are favorable with no apparent reductions of perm and gas rates three or more times higher than results from simple water-sand fracs. In experience, use of VES increases the cost of a $16,500 frac to about $23,000. Because VES is mixed "on-the-fly," only the required concentration is determined in real time during the frac, and consequently very little waste occurs. If water alone is successful, use it. But, VES is an attractive alternative.

Testing and a sequential approach to stimulating the coals is the most cost-effective way of developing CBM wells. As discussed above, all wells cannot be treated in the same manner. Some need little or no stimulation and others need all that they can get. I cannot emphasize too much how valuable the knowledge obtained from simple perm testing is to the intelligent design of what stimulation technique is appropriate in which well and in which areas. In practice, it has been advantageous to first do simple, low-rate pump-in and falloff perm testing. The higher perm wells have many times been stimulated adequately by water-only injections at frac propagating rates using a single frac pumper with only two frac tanks. The cost for this treatment has run from $2,500 to $3,500. Results from this method have been both temporary and permanent. Nominally, rates in good perm areas have peaked at 70–80 Mcfd and about 15% of the wells have achieved peak rates of 120–175 Mcfd with the water only breakdowns. The small quantity of fluid used in these treatments does not create extensive fractures and production indicates that a conventional water-sand frac needs to be remedially accomplished in 12–18 months. Remedial results achieve initial rates approaching peak rates from wells that received water-sand fracs at the outset.

One advantage to using this water-only stimulation method first is during the wetter seasons where minimizing mobilization of only 20% of the usual tanks and vehicles on the road and location causes less damage and dozer cost. Frequently, wells have been able to be put on line many months earlier using this stimulation technique rather than waiting for the seasons to change. This has enhanced the flexibility of timing for drilling and completion over more of the year.

TABLE 1.—Economic Factors for Four Well Types

	Vertical		Horizontal	
Well types	Normal	Marginal	Normal	Marginal
Well cost	$95,000	$95,000	$400,000	$400,000
EUR (MMcf)	320	111	600	400
Finding cost ($/Mcf)	$0.30	$0.86	$0.67	$1.00
Drainage (acres/well)	80	28	160	107
Number of wells to drain 640 acres	8	23	4	6
Development cost/640 acres	$760,000	$2,185,000	$1,600,000	$2,400,000
Rate of return (%)	>100	33.3	>100	29.71
Payout (years)	0.67	2.67	1.08	3.00
Cash on cash	9.77 to 1	2.73 to 1	4.60 to 1	2.84 to 1
12% DCF/640 acres	$3,655,096	$1,493,114	$2,922,512	$1,282,866

CBM PRODUCTION

Length of Time before Production

How long do you have to wait to get production? All of the variables that we discussed before in this paper plus factors such as well "productive-pod" size and aquifer-recharge rate come into play. The production graphs on Figures 1–4 are representative of what you may encounter.

Figure 1 shows an updip reservoir-extension well in a well-developed field. Peak rates occurred in 8–9 months. Figure 2 depicts a well in a field expansion in a more level position to other wells. Slightly more than 2 years were needed to dewater the well and achieve production that indicated steady state and extent of the reservoir. Figure 3 is a well drilled in a slightly less-permeable area than the previous two wells. Average perm in this region is 15 md compared to the 25–30+ md in the other two wells. Finally, Figure 4 is a well that stretches your limits of patience. For more than 6 years and multiple pump changes, the well now appears to be peaking at 75 Mcfd. This well is in a lower-perm region and is also on the edge of the field and is what we term as an "outpost" well that basically helps hold any aquifer recharge away from the more interior wells in the field.

The expected value of a good well in this field constructed from the higher perm 101 wells will peak at 123 Mcfd at approximately 1.5 years with an EUR of 320 MMcf. Figure 5 represents this well.

Figure 6 shows the other side of the economic coin, the lower third of the wells in the field that are in areas having lower permeability or other reservoir/engineering problems. These wells peak on an average of 13 months and at a max rate of 43 Mcfd and an EUR of 111 MMcf.

Horizontal wells have become an alternative to vertical wells and have shown some utility in improving production in areas where vertical wells are either marginal or unsuccessful. In the vertical well in Figure 6, a horizontal well may provide an alternative.

The economics vary for the horizontal wells as Figures 7 and 8 illustrate. Figure 7 is a good, average horizontal well that has an IP of 400 Mcfd and an EUR of 600 MMcf. These wells are customarily drilled on 160-acre spacing with a cost in the low $400,000 range. In the cases where the horizontal is drilled in one of the lower producing areas, Figure 8, the cost is the same and currently achieved productive profiles indicate EURs in the 400 MMcf range.

Play Out of Economic Alternatives

How do these economic alternatives play out? Table 1 summarizes the economic factors for four characteristic well types: vertical water-sand–fraced well with good response, marginal vertical well, good average horizontal well, and horizontal well drilled in low- permeability areas. The economic summary shown in Table 1 is based on recovering 2.5 billion cubic feet (Bcf) of gas per section, a $^{3}/_{16}$th lease, $650/month LOE, and $5.00/Mcf gas. The economics are equalized by the number of wells assumed to be necessary to effectively drain a 640-acre section.

What does this tell me? When things are going fine and you have the expertise, the vertical CBM well has a purely economic advantage of 2 to 1 of efficiency of capital (acres developed per dollar) and cash returned for dollar invested. Average marginal vertical wells and either remedial or marginal horizontal wells are too close to call.

What you normally will do depends on what you know how to do. Is your company experience/preference vertical with frac, or is it horizontal? You will do what you know how to do best. For the little guy trying to grow a CBM project up, vertical is probably the best and the most efficient use of his money, but he has to acquire the knowledge base or rent it. There is the factor of how many little wells you want to handle. And, it all boils down to how easily the path you take leads you to achieve your company goals and how strong your management team is oriented toward one method. And, change is the big villain.

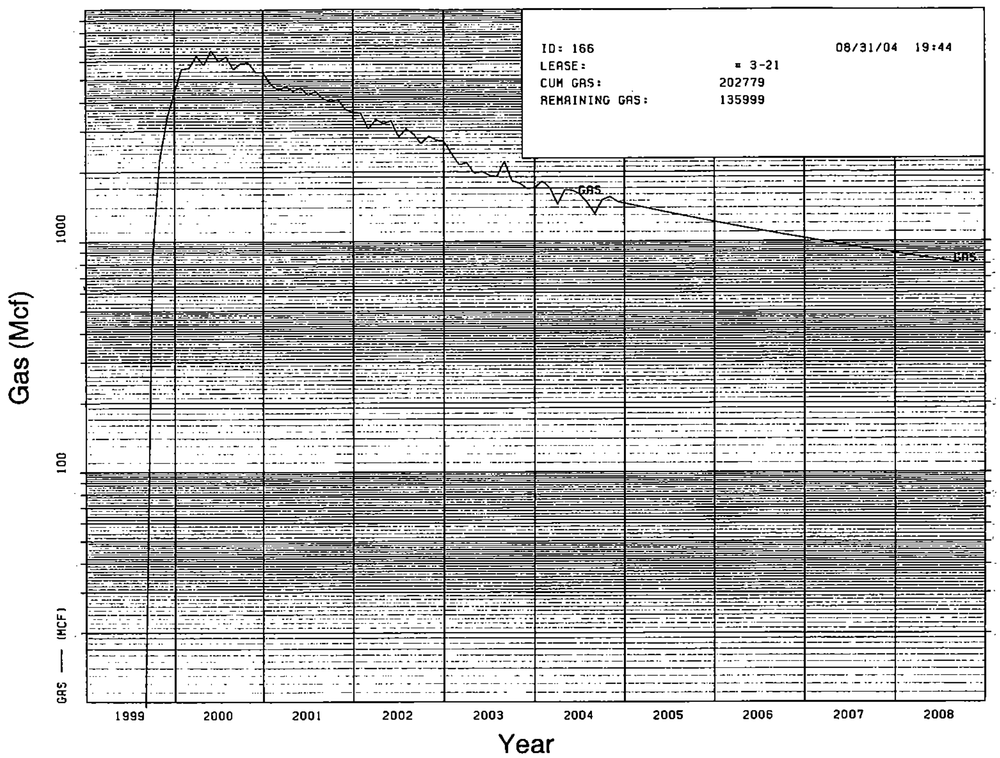


Figure 1. Production curve (volume of gas versus year) for updip extension well in well-developed field showing peak production at 8–9 months. Gas volume in thousand cubic feet (Mcf).

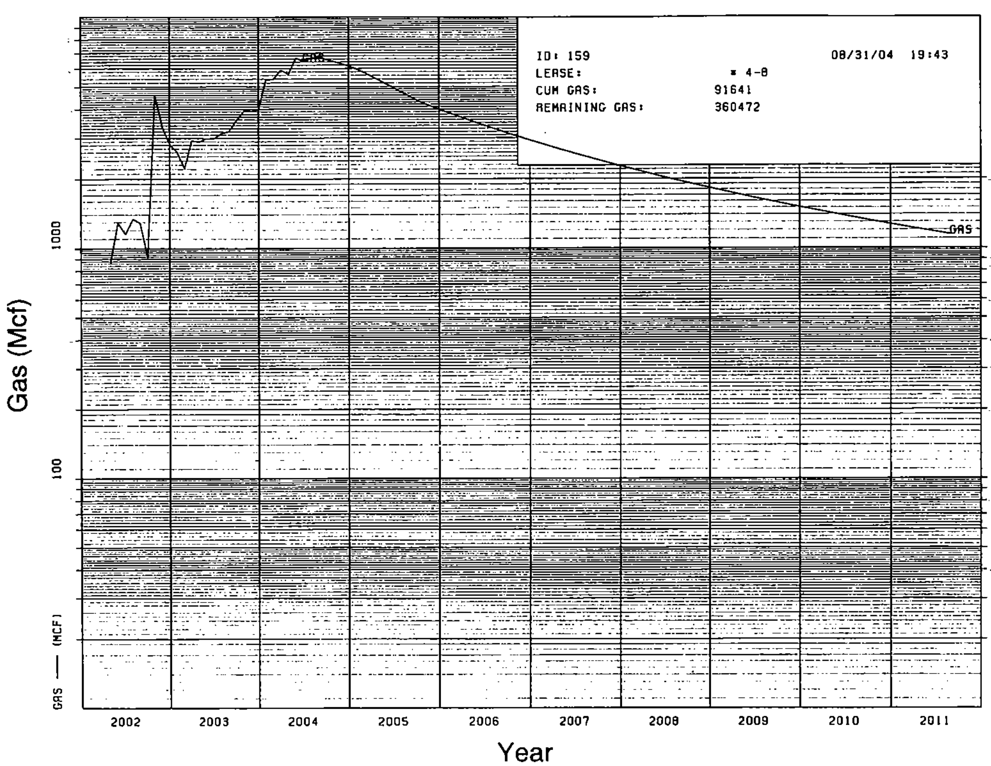


Figure 2. Production curve (volume of gas versus year) for development well in level position to producing wells at steady state for 2 years. Gas volume in thousand cubic feet (Mcf).

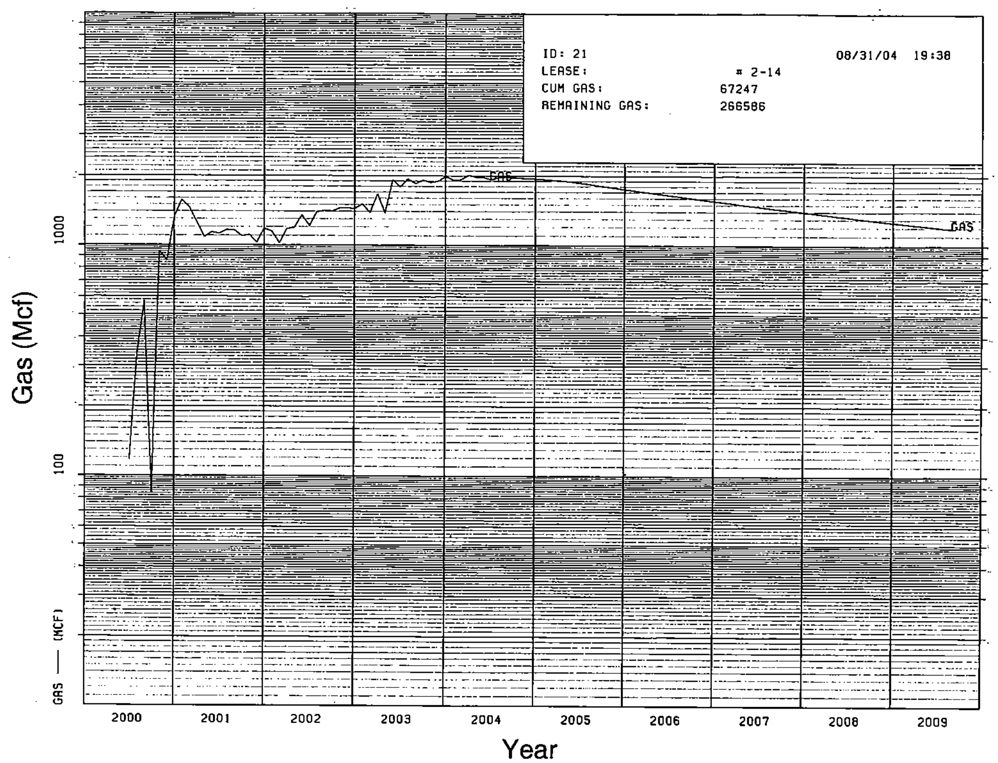


Figure 3. Production curve (volume of gas versus year) for low-permeability (15 md) well in an area that is slow to dewater. Gas volume in thousand cubic feet (Mcf).

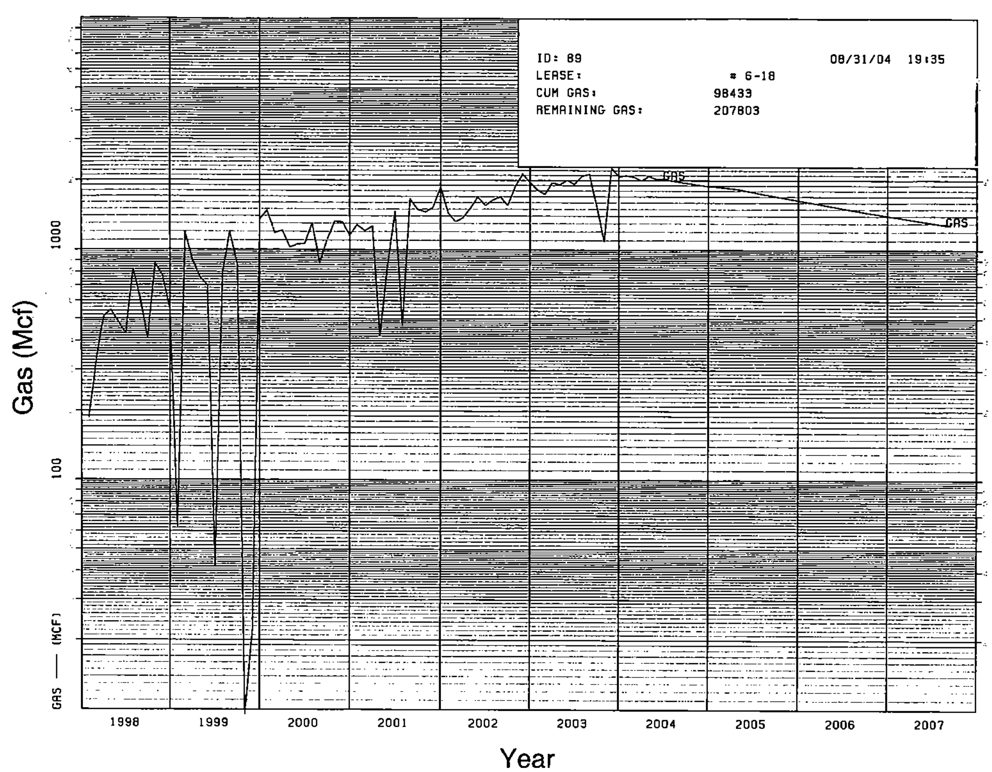


Figure 4. Production curve (volume of gas versus year) for downdip well in high-recharge area reached peak production at 6+ years. Gas volume in thousand cubic feet (Mcf).

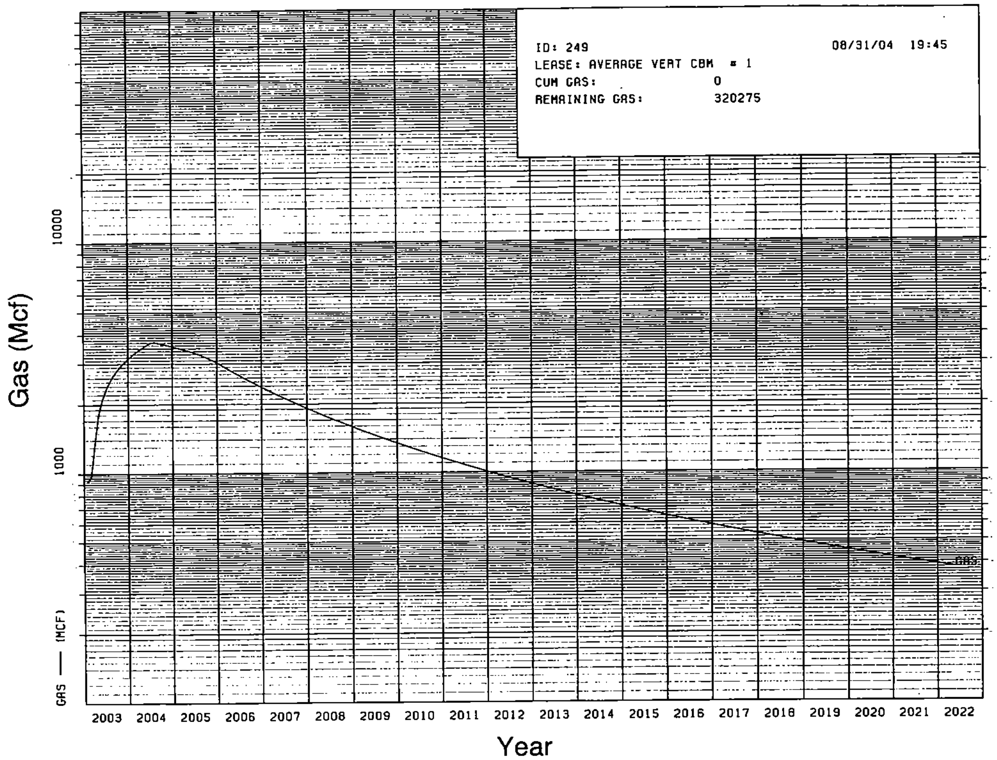


Figure 5. Production curve (volume of gas versus year) for an average good vertical coalbed-methane well in 25–30 md region showing peak production at 1.5 years. Gas volume in thousand cubic feet (Mcf).

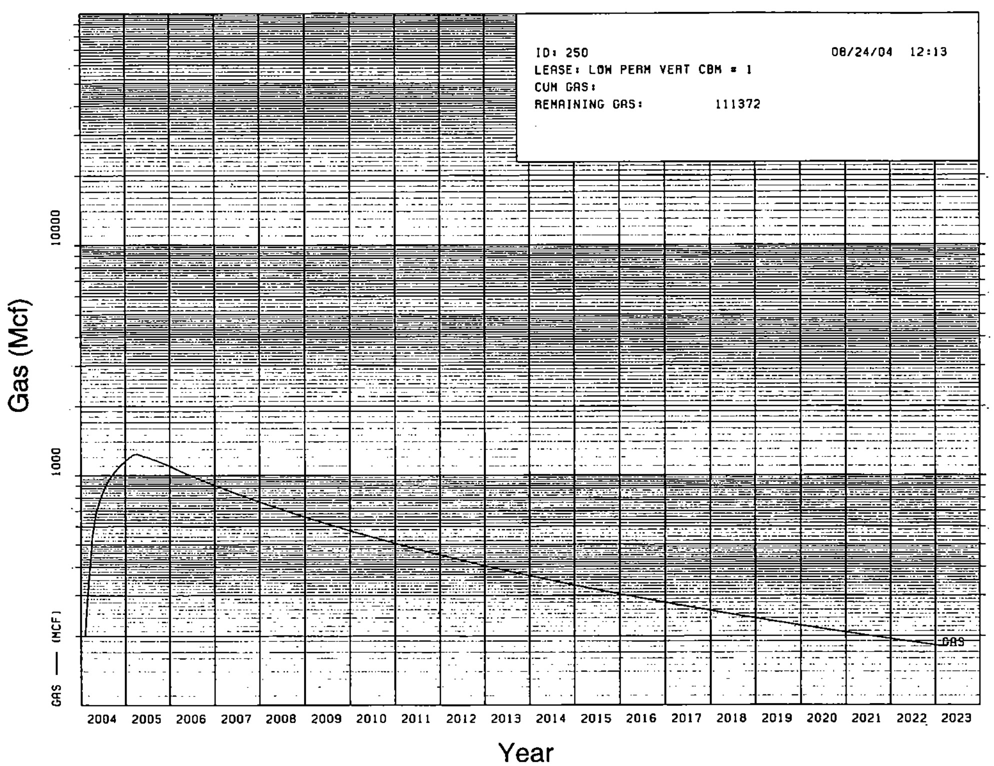


Figure 6. Production curve (volume of gas versus year) for an average well in low permeability region (10–15 md) with limited drainage area. Gas volume in thousand cubic feet (Mcf).

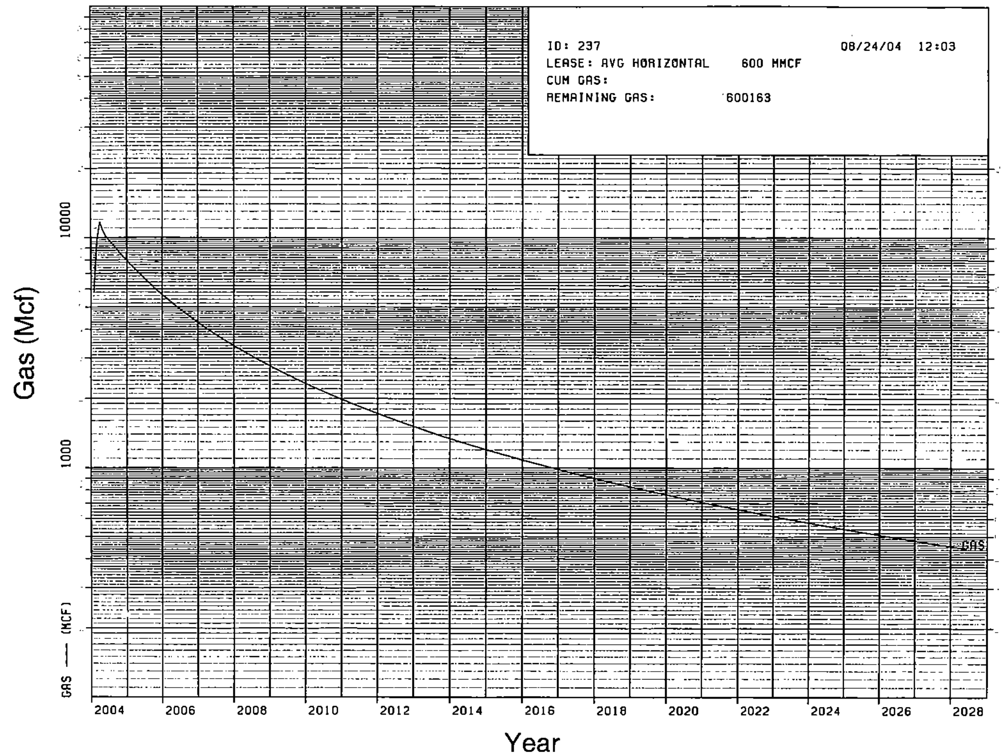


Figure 7. Production curve (volume of gas versus year) for an average good horizontal coalbed-methane well in good permeability area. Gas volume in thousand cubic feet (Mcf).

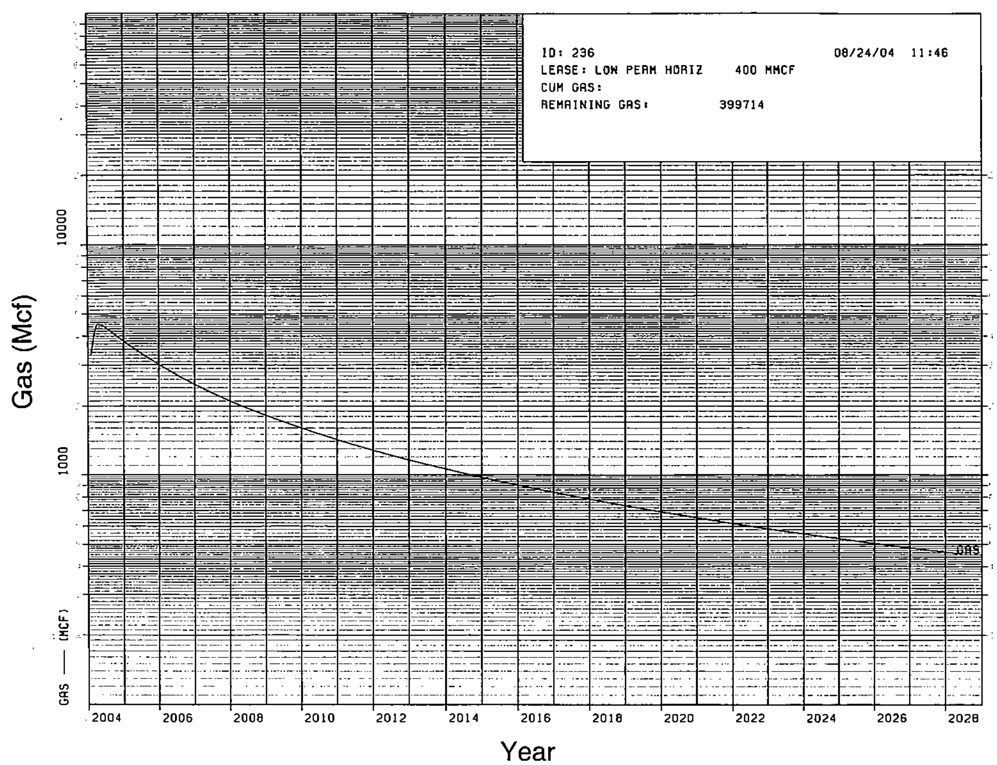


Figure 8. Production curve (volume of gas versus year) for a horizontal coalbed-methane well in low permeability or partially depleted area. Gas volume in thousand cubic feet (Mcf).

Using Traditional Completion Practices to Optimize Horizontal CBM Wells in the Hartshorne Coal, Arkoma Basin, Oklahoma

Brian D. Weatherl
Source Rock Energy Partners, L.L.C.
Tulsa, Oklahoma

ABSTRACT.—Historically, the oil and gas industry has used multiple problem-solving techniques to optimize well completions. Coalbed-methane (CBM) development is continuing to increase in activity throughout the United States and Canada. These completions require a great deal of care and attention to detail in order to preserve the maximum degree of coal permeability.

Arkoma Hartshorne CBM practices are continuing to evolve. To date, trial-and-error techniques used in more than 500 horizontal CBM wells have revealed that several substances once thought to be inert to the rock and fluid system show signs of reducing the ability of coal to transmit gas. These observations have resulted in a number of best practices used in the lateral drilling, flow back, and production of Hartshorne horizontal CBM wells in the Arkoma Basin.

Weatherl, B. D., 2005, Using traditional completion practices to optimize horizontal CBM wells in the Hartshorne coal, Arkoma Basin, Oklahoma, *in* Cardott, B. J. (ed.), Unconventional energy resources in the southern Midcontinent, 2004 symposium: Oklahoma Geological Survey Circular 110, p. 115.

Horizontal Drilling the Lower Hartshorne Coal, Arkoma Basin, Oklahoma: Techniques and Results

Curtis B. Matthews
Samson Resources
Tulsa, Oklahoma

ABSTRACT.—Horizontal drilling is a technique designed to increase production using a single well to replace multiple vertical wells. It is in its intermediate developmental stage, although it has been tried in several basins with mixed results.

Drilling in the Arkoma Basin has fostered the study of coal-seam horizontal drilling, and has proved its worth both in decreasing finding and development costs and by dramatically increasing production. It is an ideal technique for maximizing production from low-permeability coal seams.

The Lower Hartshorne coal in the Arkoma Basin has been a target of horizontal drilling since 1998, with approximately 220 horizontal wells drilled mainly within the last 4 years. Haskell County contains most of these, with 138 wells. A single township, T. 8 N., R. 19 E., contains approximately 100 of these wells.

The target coal seam, the Lower Hartshorne, is thin, averaging 4.5 ft, with some reports of horizontal drilling within 2-ft seams. Drilling horizontally in coal seams less than 4-ft thick is both a technological and geological challenge. Steep formation dip and small faults contribute to the difficulty of staying within the coal.

Drilling and completion techniques have continually improved over the last 5 years. Earliest operators attempted air drilling and discovered problems both with directional tool damage and with cuttings removal. Operators currently are using mud when drilling the curve and water when drilling the lateral portion of the well. Most wells are drilled updip in an east or west direction that is normal to coal face cleats. This allows maximum intersection of the wellbore with the cleats and fractures and increases the drainage of formation water and gas. Operators are generally running pre-drilled liners in the laterals as opposed to the earlier unlined laterals. Some debate still exists on which technique is best and why.

The length of laterals has also increased with improvement in drilling techniques. Lateral length for wells drilled in 2003 averaged more than 2,000 ft, with some exceeding 3,000 ft. Although no strict statistical correlation exists between lateral length and production increase, there appears to be a general upward trend in production with increasing lateral length.

DRILLING HISTORY

Drilling vertical coalbed-methane (CBM) wells in the Arkoma Basin began in 1988 with Bear Production drilling on the Kinta Anticline of Haskell County. Since then, approximately 929 vertical CBM wells have been drilled in the Arkoma Basin, mainly in Haskell, Le Flore, and Pittsburg Counties. The operators for these early CBM wells created and tested the most effective techniques for drilling, cementing, completing, and producing these types of wells. There is still some debate concerning which completion and production practices yield the best results.

In 1998, Bear Production was again in the forefront, drilling the first Arkoma Basin horizontal CBM well, also in Haskell County. Since 1998, approximately 273 horizontal wells (Fig. 1) have been drilled in the Arkoma Basin, an estimated half of these on the north flank of the Kinta Anticline. As before, the early operators had even more to learn about discovering the best techniques for drilling and staying within the coal.

HORIZONTAL VERSUS VERTICAL DRILLING

There are valid reasons to drill a horizontal well, even though the cost exceeds that of a vertical well by 250–300%. The average daily rate of 133 vertical CBM wells drilled and producing in T. 8 N., R. 19–20 E., with 12 full months of production for the year 2002 are shown in Figure 2. This area also has numerous horizontal

Matthews, C. B., 2005, Horizontal drilling the Lower Hartshorne coal, Arkoma Basin, Oklahoma: techniques and results, *in* Cardott, B. J. (ed.), Unconventional energy resources in the southern Midcontinent, 2004 symposium: Oklahoma Geological Survey Circular 110, p. 117–122.

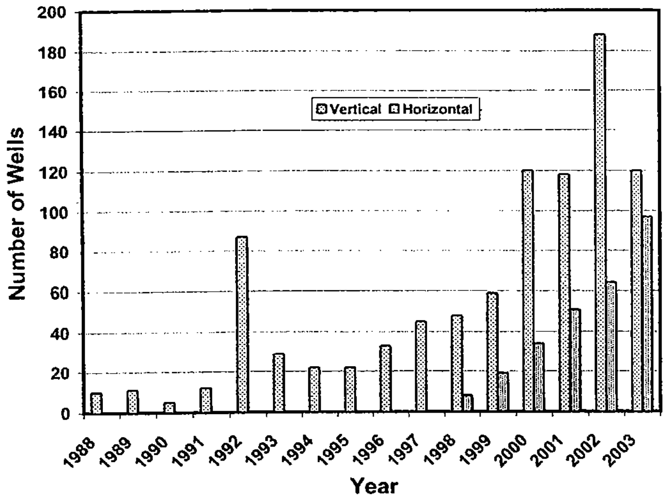


Figure 1. Number of vertical and horizontal CBM wells drilled by year in the Arkoma Basin, Oklahoma.

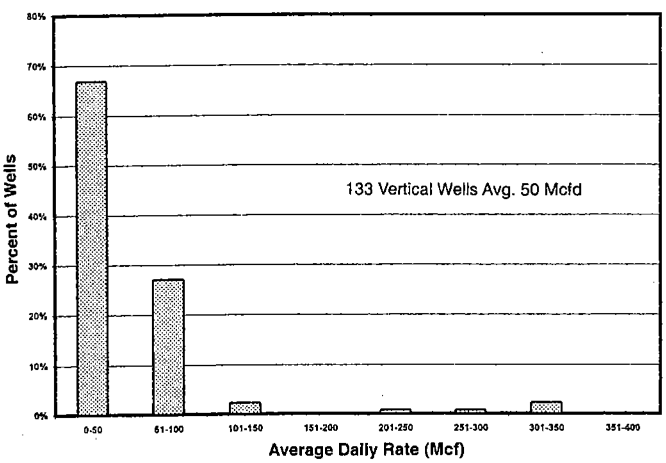


Figure 2. Average daily rate of 133 vertical CBM wells drilled and producing in T. 8 N., R. 19–20 E., with 12 full months of year 2002 production.

wells with comparable production histories. Average production in the 133 vertical wells is 50 thousand cubic feet per day (Mcfd). Sixty-seven percent of these wells produced <50 Mcfd, and 95% of the total produced <100 Mcfd. The production-distribution plot shows clustering towards the lower end of the histogram.

The average daily production rate from 78 horizontal wells in the same area is shown in Figure 3. Average production for these horizontal wells is 241 Mcfd for the year 2002. The production plot shows a more even distribution around the average rate. Production from horizontal wells averages five times the amount from a vertical well, sometimes even exceeding vertical-well production by a factor of 10–15. Based on production rates, horizontal wells are more economically viable than vertical wells.

HORIZONTAL-DRILLING TECHNIQUES

Successful horizontal drilling requires meticulous well planning, experienced directional drillers and wellsite geologist, the ability to visualize in three dimensions, and a certain amount of luck.

Good well planning is of paramount importance in drilling a successful horizontal well. The initial setup must be done properly, with the correct depths and choice of a drilling azimuth that will intersect the maximum number of face cleats. This requires extensive knowledge of the area geology and detailed maps of the target formation. Most operators drill in an east or west direction, perpendicular to face cleats, and at a 90°–95° angle. If sufficient well control does not exist in the area, drilling a vertical pilot hole through the target, logging it, and plugging back to the kickoff point (KOP) is a viable option to obtain well-planning data.

If the well is planned without the information from a pilot hole, it is air-drilled with an 8¾ in. bit down to the KOP, approximately 400 ft above the Lower Hartshorne coal. It is prudent to have the geologist correlating during drilling to prevent drilling past the KOP. At the KOP, the wellbore is loaded with mud and directional tools are run into the hole. A gamma-ray log is obtained while the directional tools are being run into the hole. This gamma-ray log is run at a sufficient depth above the KOP to include marker beds vital in correlating geological zones used to determine the exact KOP. The curve is built at a rate of 15° per 100 ft (Fig. 4), which will place the top of the coal 400 ft horizontally from the surface location. As the curve builds, the gamma-ray log must be correlated with nearby well logs, and the actual depth to the target is adjusted as needed. In a 4- or 5-ft–thick coal, the target should be intersected by the wellbore at an 86°–87° angle. This allows the curve to be landed 40 ft farther out horizontally within the middle of the coal and at the correct angle of dip to stay within the seam. If everything goes as planned, the curve should be drilled in 24 hours, at which point the 7-in. casing is run and cemented.

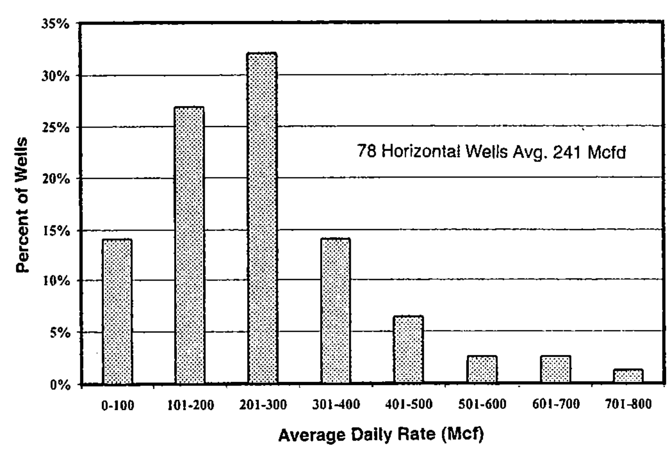


Figure 3. Average daily rate of 78 horizontal CBM wells drilled and producing in T. 8 N., R. 19–20 E., with 12 full months of year 2002 production.

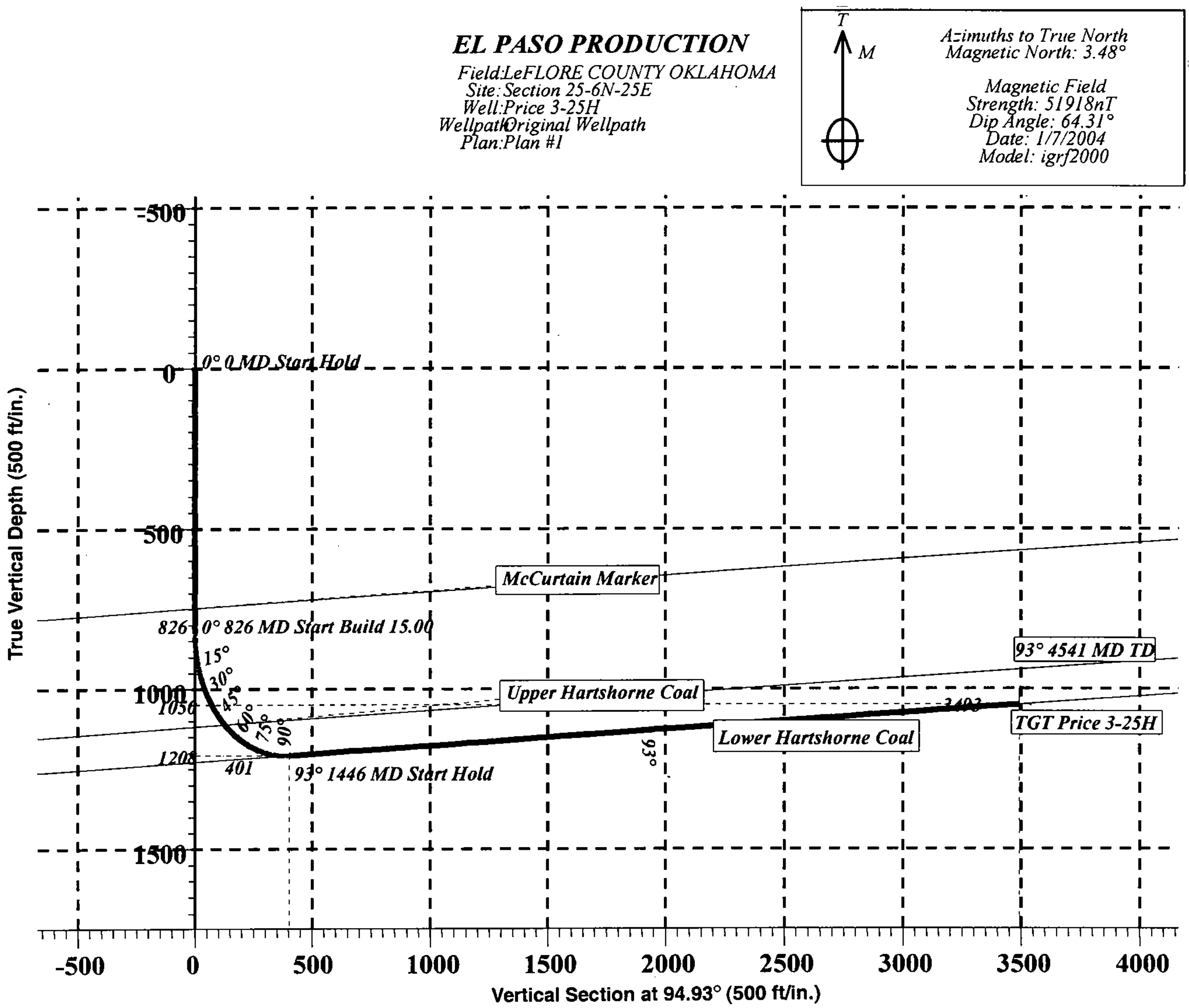


Figure 4. Well plot showing build rate and distances to coal target.

The lateral portion of the well is drilled with water and a 6⅛ in. bit. The tool contains a focused gamma ray that allows the tool face sensor to be turned up and then down for gamma-shot readings in order to determine the proximity of the coal/shale interface. As the curve is landed in the middle of the coal seam, proximity to the upper boundary of the seam will be reflected in the upshot gamma reading increasing over the downshot gamma reading, and the reverse for an approach near the bottom boundary of the seam. Thus, the drilling angle can be adjusted in order to stay within the coal seam. As the lateral is being drilled, it is advisable to plot the directional data and gamma shots. Figure 5 shows the plot of a well in the Kinta Anticline area with the focused gamma-ray shots correlating with the angle changes. The coal occasionally exhibits gentle undulations due to differential compaction. Apparent coal undulation can occur if the bit is drifting updip or downdip, forcing the directional driller to continuously change the azimuth to stay within the coal. Staying on the planned azimuth is more difficult in the areas of higher formation dip.

Depending on the planned length, it takes approximately 3 days to drill the lateral portion of the well. There is still some debate concerning whether a liner should be run or whether the well should be left unlined. A 4½ in. diameter pre-drilled liner is generally run by most operators.

POTENTIAL PITFALLS

Unplanned events while drilling and completing can cause costs to escalate. The pitfalls discussed below are based on the experience gained while drilling 60 horizontal wells and input of other operators.

Of primary importance when planning the well is to triple check every calculation. A simple error at this point can have disastrous results during the actual drilling. Wellsite personnel must also be extra attentive and exact in all measurements and calculations. Trans-

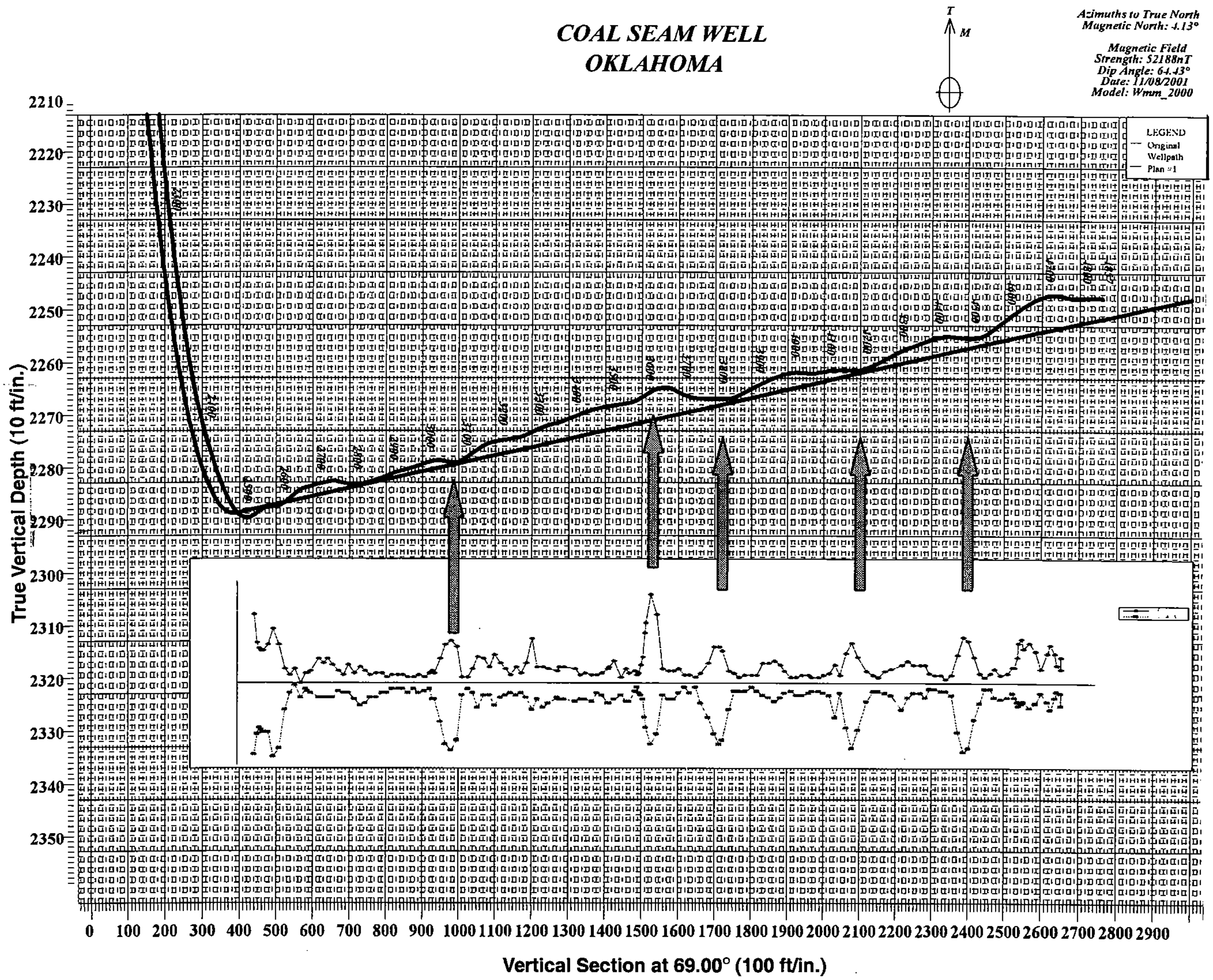


Figure 5. Final well plot of CBM well in the Kinta Anticline area showing apparent undulations in the coal. The focused gamma-ray up-and-down shots shows the increase in gamma radiation as the coal/shale boundary is approached.

posing a number or calculating an angle improperly can be a cause of immediate trouble.

An incorrect pipe tally can easily result in a missed kickoff point and necessitate re-drilling the curve. A failsafe system must be in place to calculate exact amounts of pipe on location and in the hole.

There are several factors to be aware of while drilling the curve. Because the directional sensor is 44 ft behind the bit when drilling the curve, occasionally the angle does not build as high as planned at a critical point close to the coal, generally at ~70°. By the time the low angle build is noticed, it can be too late to intersect the coal at the planned depth, necessitating redrilling from the KOP after plugging back. Closer spacing of directional readings over this interval can result in sufficient time to correct the angle build before it becomes a problem.

Landing the curve at the correct anticipated angle will greatly increase the chance of success when drilling out of the casing shoe at the beginning of the lateral, because this is the most likely spot to drill out of the top or bottom of the coal. A directional reading is not available until the sensor clears the shoe, which means the bit has drilled 30 ft prior to receiving the first reading. The natural tendency of the bit is to drop angle, thus ending up drilling out the bottom of the coal. A piece of equipment labeled a long wire would provide directional readings while the sensor is in the shoe. Because of price considerations, a long wire is generally run only if trouble is anticipated.

Faulting in the lateral portion of the well is one of the most prevalent problems in horizontal drilling and is encountered on a regular basis in the Arkoma Basin. Fortunately, most of these faults have throws of less than 10 ft, although when drilling a 5-ft coal bed, it takes very little displacement to create problems. When a fault is encountered, a decision must be made to drill upward, downward, or to abort the well. Much of the time a correct decision can be made based on data from detailed mapping, formation drag against the fault, or from drilling above or below the projected dip. If evidence does not indicate which way to drill, drilling upward is the best choice. If the coal is not found within several hundred feet, the situation needs to be re-evaluated. If the decision is made to drill downward to search for the coal, a sidetrack should be drilled in the lateral at a point before the fault is encountered. If the original decision is made to drill downward, and the coal is actually faulted upward, successful sidetracking in this situation is very difficult to accomplish. Before making any final decisions, be sure to consult with the directional driller and other wellsite personnel. They have a wealth of experience and can add valuable insight to the problem.

Besides faulting, additional geological factors may cause the coal to disappear from the wellbore. The coal may be shaled out or cut by a sand channel. If the coal is shaled out, possibly in areas where the coal is thin, drilling ahead would be the correct decision if the risk is acceptable. Drilling into a sand channel should be obvious from drill rate and cuttings evidence.

UPDIP VERSUS DOWNDIP DRILLING

Historically, one of the chief decisions involved was choosing the best direction for the horizontal drilling: updip or downdip. Some of the early wells in the Kinta area of T. 8 N., R. 19 E. were drilled downdip, whereas most of the subsequent wells were drilled in the updip direction. Eighty-eight wells from the Kinta area with 12 continuous months of non-zero production appear in Figures 6 and 7. Seventy wells were drilled in the updip direction, and 18 were drilled in the downdip direction. Lateral length is plotted against the daily rate of the month of maximum production (Fig. 6). The average daily rate for the updip-drilled wells was 388 Mcfd, and 395 Mcfd for the downdip-drilled wells, indicating that daily rate was essentially the same in both groups.

For the same two groups of wells, lateral length was also plotted against the average daily rate for twelve consecutive months of non-zero production (Fig. 7). The 70 updip-drilled wells averaged 258 Mcfd, and the 18 downdip-drilled wells averaged 224 Mcfd. The downdip-drilled wells exhibit a slightly higher rate of decline for the 12 months compared with the updip-drilled wells. The data plotted do not take into account the net linear coal footage actually included within each lateral, which could skew the data for each group of wells. Based on current production profiles, it appears that over time, the updip-drilled wells will produce slightly more than the downdip-drilled wells. This assumption can be tested when the data for the next twelve months of production becomes available.

Optimum lateral length cannot be determined presently because the majority of laterals are less than 2,500 ft in length, and insufficient logs are available to analyze the linear coal footage cut by each well. A best-fit–curve analysis for the two populations of wells in Figures 6 and 7 indicates no statistical correlation, although there appears to be an upward production trend

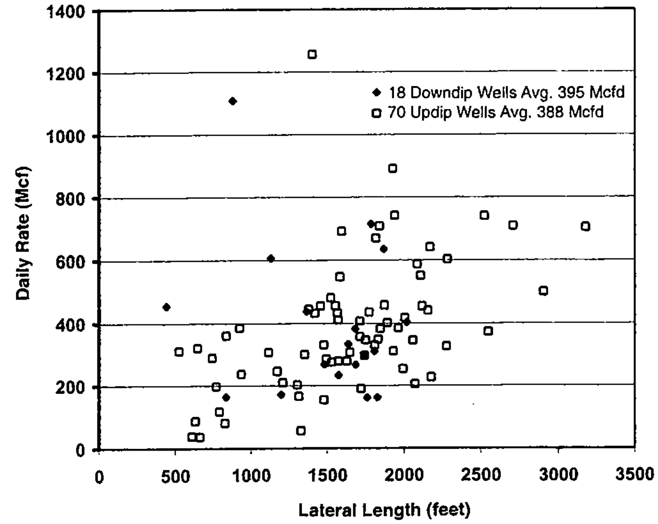


Figure 6. Lateral length plotted against the average daily rate for the peak production month of 70 updip-drilled and 18 downdip-drilled wells.

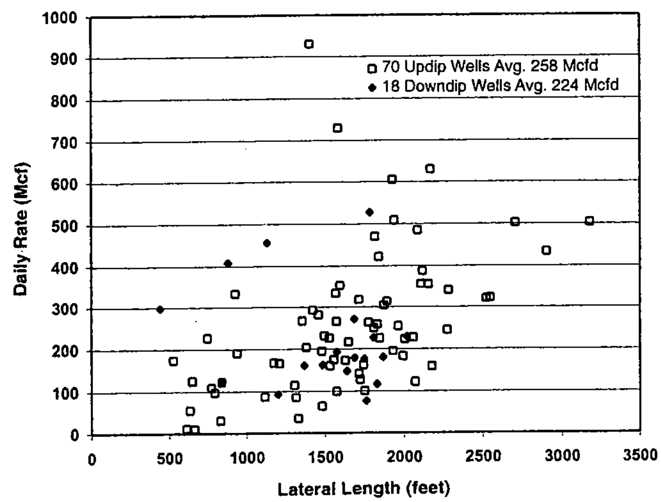


Figure 7. Lateral length plotted against the average daily rate for first 12 consecutive months of non-zero production for 70 updip-drilled and 18 downdip-drilled wells.

with increase in lateral length. As lateral lengths greater than 2,500 ft are drilled and more production history becomes available, trends may become more apparent.

CONCLUSIONS

1. Horizontal drilling is an ideal technique for maximizing production from low-permeability coal seams.
2. Generally, horizontal wells are more economical than vertical wells.
3. Drilling updip will make better production rates over time.
4. Faulting is one of the major problems when drilling horizontally.

5. Drilling pitfalls are numerous. Good well planning and communication with rig-site personnel helps avoid drilling problems.
6. A correlation between lateral length and production may exist, but the evidence does not offer statistical confirmation.
7. Proper drilling techniques are of utmost importance in horizontal wells, or they can quickly become an economic black hole.
8. Good geological correlations while drilling are necessary to drill a successful well.

Assessing Subeconomic Natural-Gas Resources in the Anadarko Basin

Kelly K. Rose
U.S. Department of Energy
National Energy Technology Laboratory
Morgantown, West Virginia

James A. Pancake, Ashley S. B. Douds, and H. R. Pratt, III
EG&G
Morgantown, West Virginia

Ray M. Boswell
U.S. Department of Energy
National Energy Technology Laboratory
Morgantown, West Virginia

ABSTRACT.—Natural-gas–resource assessments are a commonly used tool by industry, academia, and government to understand the recoverability of the nation's resource base. However, these resource assessments are commonly very limited in their ability to predict the role of technology in expanding recoverability and therefore tend to present static pictures of a resource that is, in reality, highly dynamic. Therefore, to assist in its effort to identify the most promising approaches to expanded resource recoverability, the U.S. Department of Energy's National Energy Technology Laboratory (NETL) is conducting a series of detailed gas-in-place (GIP) characterizations of key segments of the nation's under-utilized gas resource base. These assessments, when combined with estimations of regional variation in reservoir permeability, allow iterative computer modeling to measure the potential economic and technical recoverability of gas resources under a variety of technology/policy scenarios.

The NETL currently is finalizing its assessments of the mid-Pennsylvanian and older strata of the deep Anadarko Basin. Published literature and industry-related data were studied to identify those strata, which encompass a majority of the basin's under-utilized deep, unconventional, or otherwise sub-economic resources. As a result, assessment efforts in the deep Anadarko Basin have focused on the following where they exist at measured depths greater than 10,000 ft: the Desmoinesian, Atokan, Morrowan, Springeran, Chesterian, Meramecian, and Osagean Series, and the Hunton, Simpson, and Arbuckle Groups.

These stratigraphic units were subsequently bundled into Units of Analysis (UOAs), packets of resource, similar to the concept of a play, that exist in a common geologic condition, and that are appropriate to characterize within the model as the target of individual wells. In the deep Anadarko Basin eight UOAs were compiled based on these criteria including the (1) Deese; (2) Atoka; (3) Morrow; (4) Springer, which is comprised of the Springer clastic facies only; (5) Mississippian, which includes the Springer carbonate facies, and the Chesterian, Meramecian, and Osagean Series; (6) Hunton; (7) Simpson; and (8) Arbuckle.

Key geologic and engineering parameters including depth, potential pay thickness, porosity, pressure, water saturation, and temperature were determined through the correlation and analysis of hundreds of log suites, drilling, and completion records and were used to produce detailed characterizations of the GIP for each UOA. These analyses, in conjunction with DOE modeling efforts and permeability analyses, provide a detailed, disaggregated, geologic and engineering database for the Anadarko Basin, and support efforts to model the impact of different technology scenarios on the future of U.S. natural-gas exploration, production, and supply.

Rose, K. K.; Pancake, J. A.; Douds, A. S. B.; Pratt, H. R., III; and Boswell, R. M., 2005, Assessing subeconomic natural-gas resources in the Anadarko Basin, *in* Cardott, B. J. (ed.), Unconventional energy resources in the southern Midcontinent, 2004 symposium: Oklahoma Geological Survey Circular 110, p. 123–129.

BACKGROUND

The United States presently has an estimated 1,400 trillion cubic feet (Tcf) of technically recoverable natural-gas resources. However, much of this resource base is currently uneconomic to produce, and less than 2% is currently discovered (National Petroleum Council, 1999). Therefore, even as demand for natural gas in the United States grows, it is becoming increasingly difficult for domestic producers to provide and maintain an affordable natural-gas supply to consumers. One significant economic and technical impediment is the increasing need to tap complex, deep, and unconventional resources for reserve replacement. Despite recent progress in the exploration and production (E&P) of these unconventional plays, significant advances in technology will be needed in order to make them economically viable.

Studies completed by the National Petroleum Council (1999, 2003) recommended that the federal government place a high priority on research and development (R&D) that targets unconventional natural gas to assure the future viability of a strong, domestic natural-gas–resource base. In response to these and other recommendations, the National Energy Technology Laboratory (NETL) Strategic Center for Natural Gas and Oil (SCNGO) implements a portfolio of R&D projects designed to enable and accelerate the transition of sub-economic resources into economically recoverable resources and ultimately reserves.

In 2001, NETL launched a comprehensive program to assess the long-term sustainability of the domestic natural-gas supply in the United States. As part of this effort, a coordinated program combining technology tracking, industry tracking, and resource characterization, with national modeling of natural gas E&P technologies, was implemented to provide a better understanding of three key issues impacting the long-term, domestic, gas supply: (1) the size and nature of underutilized gas resources in domestic basins, critical to future supply; (2) the potential of technology to accelerate the conversion of "unrecoverable" and sub-economic resources into economically recoverable resources; and (3) the volume and nature of resources present on federal lands.

This approach helps NETL identify the R&D requirements needed to provide both (1) advances in incremental technology that steadily increase the recoverability of the known resource base and (2) technological "leaps forward" that result in the addition of vast resources that were previously unknown, overlooked, or undervalued.

RESOURCE ASSESSMENTS AT NETL

Natural-gas–resource assessments are a tool commonly used by industry, academia, and government to understand the recoverability of the nation's resource base. Historically, resource assessments have produced a static view of the natural-gas–resource base, a resource that is in reality highly dynamic. These assessments make assumptions about the economic or technical producibility of the gas-resource base, thereby leaving significant portions of the in-place resource uncharacterized and unaccounted (Fig. 1). A recent example illustrating the reclassification of previously unaccounted gas resources is coalbed methane, which is now viewed as a significant part of our nation's natural-gas reserves. NETL is not interested in producing a "most likely" estimate of future technically or economically recoverable resources. Instead, NETL creates detailed gas-in-place characterizations from which our computer models estimate unique estimates for future technically or economically recoverable resource volumes for a wide variety of alternative future technology and policy scenarios, many of which may be considered highly unlikely at the present.

Gas-in-Place (GIP) assessments aim to quantify the total volume of gas in the assessed area. These assessments ideally seek to quantify every molecule of gas in a given formation and region; however, they are typically limited to broad constraints placed on the lithology, thickness, porosity, water saturation, and/or depth.

Technically Recoverable (TR) assessments seek to predict what portion of the gas resource base would be producible given current technology standards and no economic limitations.

Economically Recoverable (ER) assessments seek to quantify that portion of the resource base which is economically producible at market conditions at a given moment in time.

Figure 1. Definitions for gas-in-place, technically recoverable, and economically recoverable resources.

Phase one of this work, completed in the spring of 2003, assessed the gas resources of the Greater Green River and Wind River Basins in Wyoming and Colorado. Phase two, scheduled for completion soon, includes the Uinta and Anadarko Basins. Although much of the approach and methodology for these assessments is the same, aspects of each assessment are tailored specifically to each basin. Therefore, the remainder of this paper focuses on discussion of the assessment work for the mid-Pennsylvanian and older strata of the "deep" Anadarko Basin.

SELECTION OF STUDY AREAS AND UNITS OF ANALYSIS

Recently published reports and studies have emphasized the significant natural-gas–resource base in low-permeability formations of the Rocky Mountain region. As these resources are primary targets for NETL's R&D program, the Greater Green River and Wind River were the initial basins studied. However, an increased emphasis on deep gas R&D at NETL warranted assessment of emerging plays in low permeability and deep formations of the Anadarko Basin, such as the Springer play.

The NETL assessment team studied published literature and industry-related data to identify those strata in the Anadarko Basin which encompass the majority of the basin's under-utilized "deep," unconventional, or otherwise sub-economic resources. The assessment team then considered regional geology, completion practices, needs of the NETL models, and time and resource constraints to finalize the selection of Units of Analysis (UOAs). UOAs are bundled packets of resource, similar to the concept of a play, that exist in a common geologic condition, and that are appropriate to characterize within the model as the target of individual wells.

As part of the team's review of the Anadarko Basin, it was recognized that most formations had significant shallow-production histories. However, current technological constraints have significantly limited the successful exploration, drilling, and production of formations at depths greater than 10,000-ft measured depth. Therefore, the assessment was limited to areas where each UOA occurred at drilling depths of 10,000 ft and greater.

In the "deep" Anadarko Basin, eight UOAs were chosen for assessment based on the criteria outlined above: (1) Deese; (2) Atoka; (3) Morrow; (4) Springer, which is comprised of the Springer clastic facies only; (5) Mississippian, which includes the Springer carbonate facies, and the Chesterian, Meramecian, and Osagean Series; (6) Hunton; (7) Simpson; and (8) Arbuckle (Fig. 2).

It is important that two additional UOAs—the Granite Wash and the Woodford Shale—were identified as having significant natural-gas–resource potential. However, given the unique geologic characteristics and assessment requirements of the Granite Wash and Woodford Shale, they were not included in this phase of the study but rather were identified as targets for future analysis.

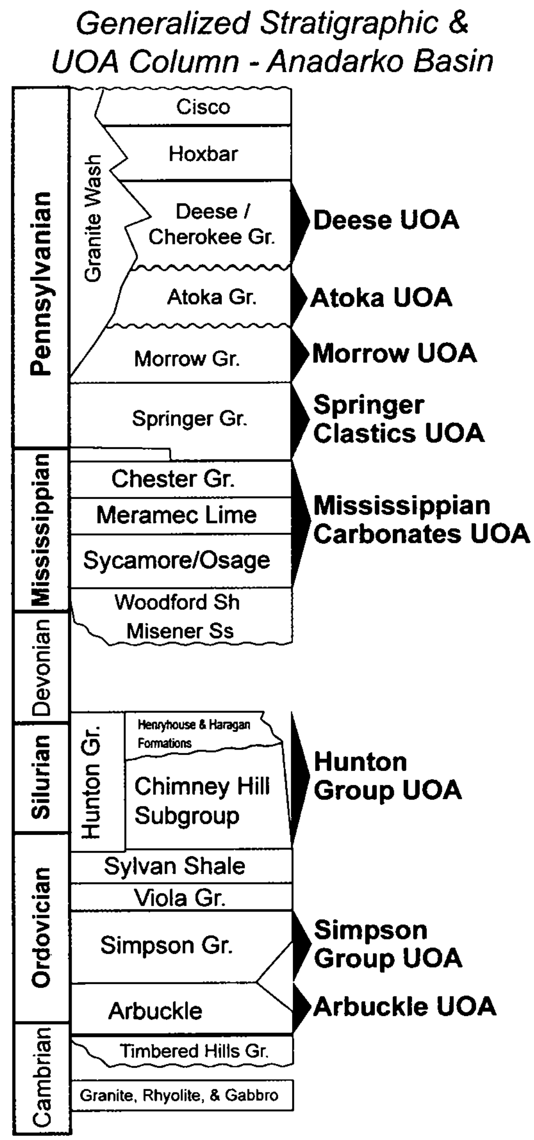


Figure 2. Generalized stratigraphic column illustrating the stratigraphy included in each of the eight UOAs analyzed in the deep Anadarko Basin gas-resource assessment.

VOLUMETRIC PARAMETERS

Geographically the study area included portions of Beaver, Beckham, Blaine, Caddo, Canadian, Cleveland, Comanche, Custer, Dewey, Ellis, Garvin, Grady, Harper, Kingfisher, Major, McClain, Roger Mills, Stephens, Washita, and Woodward Counties in Oklahoma, extending west into the Panhandle region of Texas, including portions of Gray, Hemphill, Lipscomb, Ochiltree, Roberts, and Wheeler Counties. The northwestern extent of the study area changes to correspond with the 10,000 ft measured depth cut off for each UOA. The southern boundary for each UOA corresponds to the structural features of the Wichita Mountain Uplift, while the eastern boundary is truncated by erosional and/or structural features related to the Nemaha Uplift (Fig. 3).

Hundreds of well-log suites were loop-correlated throughout the basin to characterize and understand the occurrence and distribution of each UOA's lithofacies. In addition to the major UOA boundaries, individual sandstone and limestone correlations were also made to ensure the consistency of the broader UOA correlations and to assist mapping and cross-section interpretations. Net thickness, "potential pay" thickness, and drilling mid-point/structure maps were constructed for each UOA (Fig. 4), and a series of strati-

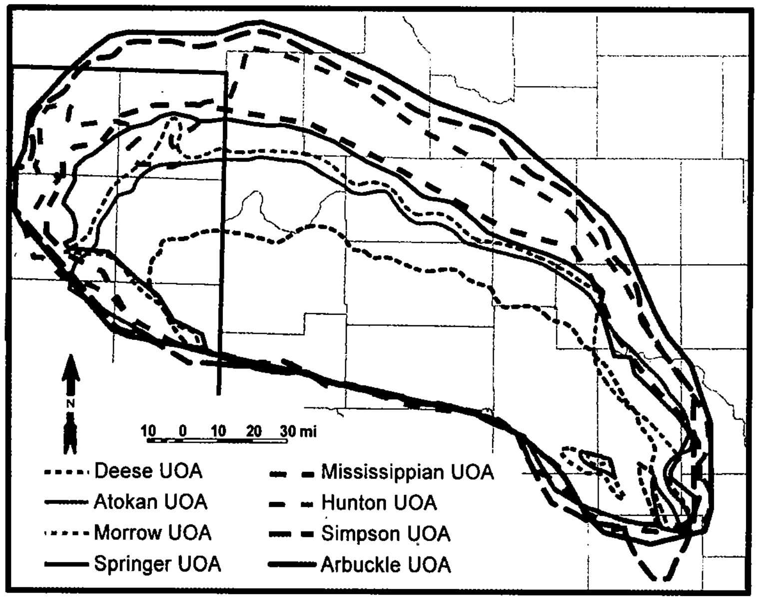


Figure 3. Map illustrating the geographic limits of each UOA assessment area.

graphic and structural cross sections were developed across the deep basin to illustrate the regional distribution and lithologic nature of each UOA.

Well-log suites were analyzed to determine key geologic and engineering parameters for each UOA, including drilling-midpoint depth, potential pay thickness, average porosity, v-shale, and average resistivity. The goal was to obtain data at an area-grid scale of one-well-per-township; however, for the older formations, and in the deepest portions of the basin, this level of data density was not always obtainable. Data-collection techniques and analyses were also adjusted to ensure data accuracy and to accommodate differences in lithologies, such as limestones versus sandstones. Average porosities were determined from the analysis of recent-vintage compensated density-neutron and bulk-density logs, whereas data for net thickness, average resistivity, v-shale, and drilling mid-point depth were obtained from resistivity and gamma-ray logs.

Published water resistivity (Rw) databases from the U.S. Geological Survey and Society of Petroleum Engineers were standardized and used to obtain water saturations for each UOA. Simondoux's equation was utilized for shaley-sandstone reservoirs, whereas limestone and clean sandstone water saturations were calculated with Archie. Each well in the Rw database for a given UOA were used to calculate individual water saturations at that well's corresponding drilling midpoint depth. The saturation data were then plotted geographically, and extrapolated regionally via contoured interpretations.

The volumetric parameter "potential pay" thickness requires further discussion. The term "pay" is generally equated with the thickness of an interval that is expected to produce under current circumstances. Geologists are accustomed to establishing cutoffs for practical reservoir or field-specific porosity (for example, 6 or 8%) and water saturation (commonly 60%) in determining pay. However, the goal of these assessments is to create resource descriptions that allow the models to determine what segment of the total resource might be "pay" as much as 20 years into the future under cost/technology scenarios that are very different from what currently exists. Therefore, aggressive cut-offs of 4% porosity for clastics, 2% porosity for carbonates, and 70% water saturation (Sw) were used in defining "potential pay" with the understanding that, under most technology/cost conditions, the models will not consider much of this low-quality resource to be viable.

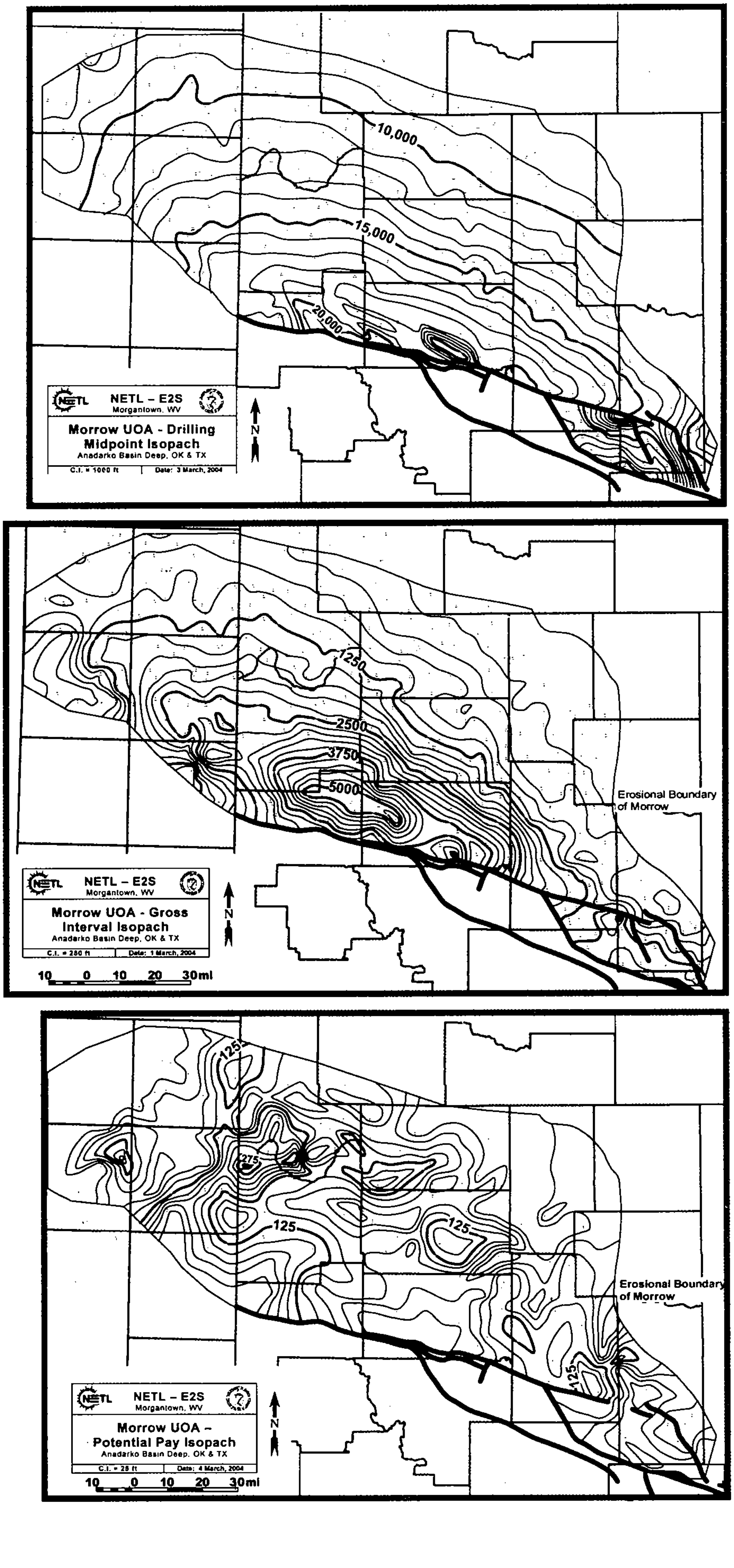
Temperature gradients for each grid cell in Oklahoma were based on the detailed master's thesis by Cheung (1975), who produced two sets of temperature-gradient contour maps for the deep Anadarko Basin. One set of gradients was for the normal geothermal gradient. The other set of gradient data and contours generally corresponded to the overpressured intervals of the deep Morrow and Springer plays. For the Texas portions of the study area, bottom-hole (BHT) log-temperature data points were corrected via Cheung's BHT correction curves and used to extend the contours into the Panhandle region of the assessment area.

Pressure data were collected primarily from the State of Oklahoma's "Pressure Data on the Anadarko Basin" website and from the IHS production database. This information consists of pressure measurements and gradients for specific formations from a variety of sources such as drill-stem tests and wireline formation tests. The gradient data were gridded across each UOA and combined with drilling midpoint depths to generate pressure profiles for each grid cell. Efforts were made to compare calculated gradients with published pressure gradients to ensure their validity.

A)

B)

C)



EFFECTIVE PERMEABILITY

The final reservoir parameter required for the model dataset is an estimation of the total effective permeability (TEP) for each grid cell in each UOA. To generate these TEP values the following analyses and methodology were conducted for each UOA.

Based on the production histories of each UOA, 10 fields geographically distributed throughout the basin were identified. From each field, one high-, one moderate-, and one low-performing well were selected for detailed production-decline curve and log-character analyses conducted by Advanced Resources International. Ideally, this would provide TEP values for 30 "control" wells in each UOA and would cover a variety of production profiles. However, the same data-density issues that affected the log-analysis efforts also pertain here, resulting in lower TEP data densities for some of the UOAs.

Porosity-permeability relationships were obtained for each UOA through the comparison of core porosity and permeability data with their corresponding log data. This relationship was then extrapolated to the TEP control wells in order to constrain the contribution of matrix permeability to the TEP of those wells. The difference between the expected matrix permeability and the TEP in the control wells was ascribed to the presence or absence of a fracture-permeability overprint in those wells.

Estimates for the fracture-related permeability in the control wells were then correlated to corresponding structural-com-

Figure 4 (left). Example maps from the Morrow UOA; similar maps were constructed for all eight UOAs. (A) Depth to drilling mid-point map for the Morrow UOA, Contour Interval (C.I.) = 1,000 ft. (B) Net thickness map from the Morrow UOA, C.I. = 250 ft. (C) "Potential pay" thickness map from the Morrow UOA, C.I. = 25 ft.

TABLE 1.—GIP Values and Average Volumetric Parameters Calculated for Each UOA Assessed in the Anadarko Basin to Date

	Anadarko Basin UOAs							
	Deese	Atokan	Morrow	Springer	Mississippian	Hunton	Simpson	Arbuckle
Area (thousands of acres)	2,650	1,509	3,672	4,328	2,340	3,773	9,007	*
Average thickness (ft)	105	81	93	131	359	41	152	*
Average porosity (%)	7.6	8.3	6.2	8.7	4.0	4.2	8.3	*
Average water saturation (%)	49	47	41	16	55	48	41	*
Average drilling depth (ft)	12,710	13,695	14,475	16,072	14,068	16,704	16,581	*
Average pressure (psi)	6,747	7,437	8,834	10,026	7,148	7,278	6,819	*
Average temperature (°F)	152	167	288	339	178	207	207	*
Average Z-factor	1.14	1.19	1.28	1.36	1.16	1.17	1.13	*
In-place resource (Tcf)	181	102	188	609	260	52	931	*
Resource below 15,000 ft (Tcf)	10	35	87	484	126	29	536	*

*Calculations for the Arbuckle UOA will be included in the final report, to be released upon completion of the project.

plexity maps. These maps were produced from the analysis of aeromagnetic, lineament, and structure maps, as well as existing published seismic and fault interpretations for the basin. The derived map relationship between fracture permeability and structural complexity was then used to extrapolate and assign an estimated fracture permeability to each grid cell for each UOA. Estimates for the core-based matrix permeabilities were also extrapolated to each grid cell based on the previously obtained core-permeability–log relationship. The sum of the estimated matrix and fracture permeabilities in each grid cell results in the estimated TEP for each cell in a given UOA.

THE VOLUMETRIC DATABASE

The data collected for each UOA were used to create a detailed, geographically and stratigraphically disaggregated database of volumetric parameters. The comprehensive and compartmentalized nature of this new dataset helps capture the natural variation in drilling, depth, porosity, water saturation, pressure, temperature, and permeability for each UOA. Gas-in-place (GIP) volumes for each UOA in the deep Anadarko Basin were calculated using this data, and NETL modelers will utilize the database to ascertain the relative success of future technologies in economically accessing this gas resource base.

GAS-IN-PLACE CALCULATIONS

Values of GIP and average volumetric parameters were calculated for each UOA through the following methodology. The previously collected volumetric data were gridded at the township scale across the basin for each UOA. Z-factor values, a volumetric parameter that describes the compressibility of natural gas under specific temperatures and pressures, were also gridded and calculated using the gridded pressure and temperature values and a gas-gravity value of 0.6 for each UOA.

These parameters were then used to calculate the GIP value for each grid cell in each UOA. Grid cells with water saturations above 70% were eliminated from the GIP calculation as were areas of significant historical production. Grid cells with remaining GIP values were then summed to determine the total GIP for each UOA. Using this methodology, geographically and stratigraphically disaggregated preliminary GIP volumes were calculated for all but one of the UOAs at the time of this report (Table 1). The remaining GIP value and more information about this study will appear in a final report that will be available through NETL upon completion of this project.

ONGOING WORK

The deep Anadarko and Uinta Basins resource assessments will conclude with the publication of a detailed final report covering both basins. This report will be made freely available on the NETL website at www.netl.doe.gov through the "publications" link.

Internally, the data from these studies will be used by the NETL analytical models to determine what portion of the GIP resource is technically and economically recoverable under a variety of technology/cost scenarios. The results of these models will be used in conjunction with other available reports and studies in order to determine what technologies and policies will have the greatest impact on reassuring the viability of our nation's natural-gas–resource base for decades to come. It is anticipated that two additional basins will be chosen for resource characterization and assessment of marginal and subeconomic gas resources upon completion of the current work.

REFERENCES CITED

Cheung, P. K., 1975, The geothermal gradient in sedimentary rocks in Oklahoma: Oklahoma State University, Stillwater, unpublished M.S. thesis, 55 p.

National Petroleum Council, 1999, Meeting the challenges of the Nation's growing natural gas demand: National Petroleum Council, Washington, D.C., v. 1, Summary Report, 96 p., http://www.npc.org/reports/ng.html.

______ 2003, Balancing natural gas policy—fueling the demands of a growing economy: National Petroleum Council, Washington, D.C., v. 1, Summary of Findings and Recommendations, 118 p., http://www.npc.org/reports/ng.html.

DATA SOURCES

Core Data

IHS Energy, 2004, Well and Production Databases, Houston, Texas.

Oklahoma Geological Survey, Oklahoma Petroleum Information Center.

Pressure Data

Oklahoma State University, Stillwater, Pressure Data on the Anadarko Basin: OSU website, http://www.okstate.edu/geology/gri/startup2.html.

IHS Energy, 2004, Well and Production Databases, Houston, Texas.

Rw Data

U.S. Geological Survey, Produced Rw Database.

Society of Petroleum Engineers (SPE), 1988, Survey of Rw Data in Oklahoma.

Temperature Data

Cheung, P. K., 1975, The geothermal gradient in sedimentary rocks in Oklahoma: Oklahoma State University, Stillwater, unpublished M.S. thesis, 55 p.

Borehead-temperature data collected from log headers.

IHS Energy, 2004, Well and Production Databases, Houston, Texas.

Well Data

IHS Energy, 2004, Well and Production Databases, Houston, Texas.

Texas Railroad Commission, Austin, Texas.

Well-Log Data

A2D Technologies, Humble, Texas.

M. J. Systems, Denver, Colorado.

In-house Microfiche.

Remagnetization and the Timing of Organic-Matter Maturation in the Woodford Shale, Oklahoma

Donald Walker, R. Douglas Elmore, and Karen Bloomfield
University of Oklahoma
Norman, Oklahoma

ABSTRACT.—The Upper Devonian–Lower Mississippian Woodford Shale has been recognized as one of the most prolific petroleum source rocks of the southern Midcontinent of the United States. The Woodford has also attracted a great deal of interest as a potential fractured-shale gas system. Numerous geochemical assessments have focused on total organic carbon and extent of thermal maturation. The determination of the timing of organic-matter maturation is also extremely important for the development of an accurate basin model. Previous paleomagnetic/geochemical studies have demonstrated that the thermal maturation of organic matter can lead to the acquisition of a chemical remanent magnetization (CRM) in secondary magnetite. This CRM can be used to date the maturation event.

The purpose of this study is to investigate the use of this approach to date the onset of organic-matter maturation in the Woodford Shale. Paleomagnetic samples were collected from thin carbonate lenses from two Woodford outcrops in the Arbuckle Mountains. Analysis of demagnetization characteristics indicates that the Woodford contains a CRM residing in magnetite. This magnetization exhibits southeast declinations with shallow to moderate inclinations. A preliminary regional tilt test indicates that the magnetization was acquired during the orogenic event of the Pennsylvanian. The pole position for the CRM plots close to the Carboniferous part of the apparent polar-wander path. The results of this preliminary study suggest that the onset of hydrocarbon maturation in the Woodford Shale occurred during the deformational event in the Pennsylvanian. However, additional sampling is needed to better constrain the timing of acquisition for the CRM.

Walker, Donald; Elmore, R. D.; and Bloomfield, Karen, 2005, Remagnetization and the timing of organic-matter maturation in the Woodford Shale, Oklahoma, *in* Cardott, B. J. (ed.), Unconventional energy resources in the southern Midcontinent, 2004 symposium: Oklahoma Geological Survey Circular 110, p. 131.

Reservoir Characterization of Coals and Carbonaceous Shales in the Western Region of the Pennsylvanian-Age Interior Coal Province

Steven A. Tedesco
Atoka Geochemical Services Corporation
Englewood, Colorado

ABSTRACT.—The Forest City and Cherokee Basins form part of the western region of the Interior Coal Province, which was the location of extensive deltaic and widespread coal deposition during Middle Pennsylvanian time. The coals are predominantly found in the Cherokee Group with localized producing areas extracting gas also from the overlying Marmaton Group. The coal seams are generally 0.3 to 1 m thick, high volatile C bituminous to potentially medium volatile bituminous rank. Even though many of these coals are extensive, many areas demonstrate that the coals are laminated and high in ash. Therefore, reservoir characteristics are downgraded because many of the coals were deposited under strong near-shore or tidal influence. The Cherokee Basin has been undergoing rapid development for coalbed methane and to a lesser extent shale gas development over the last 5 years. Certain parts of the Forest City Basin are being developed, but most of the area is still in the early stages of exploration and exploitation. Even though the coals of the Forest City and Cherokee Basins were deposited under similar environmental and tectonic conditions, subsequent geologic history for each area has been unique. Consequently, each area as well as sub-areas within each basin have different reservoir characteristics in terms of gas contents and permeability. Both basins seem to have been subject to periods of at least one degassing of the Interior Basin, episodic migration of petroleum and hydrothermal brines, and regional and localized influxes of meteoric water. Of the 20-plus named coals, less than five of these coals have produced gas or have significant gas content and as such are focusing the present trends in exploitation in each basin. Based on recent drilling, a comparison and contrast between basins as well as general identification of potentially prospective areas in each for economically recoverable coalbed methane or shale gas resources are beginning to be defined. Recent production data from the Cherokee Basin also indicates that the coals are probably not providing the majority of the gas, but the adjacent shales are contributing a significant portion. As such, the presence of shale gas as a resource can be mapped as well, and areas that would favor its development in conjunction or separately from coal can be defined.

Tedesco, S. A., 2005, Reservoir characterization of coals and carbonaceous shales in the western region of the Pennsylvanian-age Interior Coal Province, *in* Cardott, B. J. (ed.), Unconventional energy resources in the southern Midcontinent, 2004 symposium: Oklahoma Geological Survey Circular 110, p. 133.