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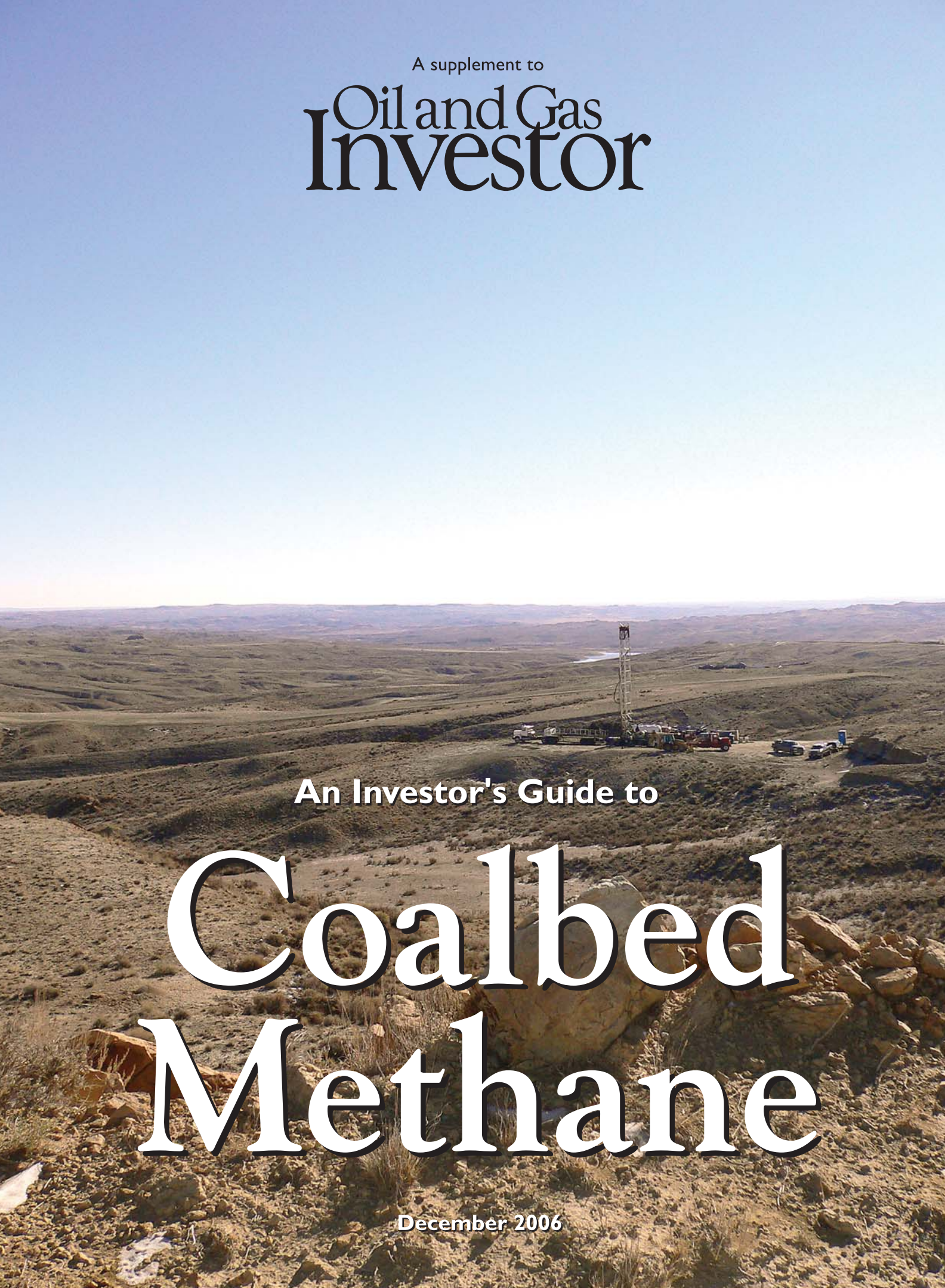

An Investor's Guide to

Coalbed Methane

December 2006

Coalbed Natural Gas Alliance

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About the cover: Bill Barrett Corp.'s Cat Creek Big George project. The view is of RTM drilling rig No. 101 during a workover on the BBC-Federal 32-29-4878. *(Photo Courtesy of Bill Barrett Corp.)*

Coalbed Methane Charges On

Unconventional gas resource plays such as shales may have attracted a lot of industry and investor attention lately, but coalbed-methane (CBM) plays continue to keep operators busy as well.

Emerging or once-overlooked CBM plays are unfolding in Washington State, Alabama, Ohio and Pennsylvania. In addition, there is continued development in more traditional areas such as the Powder River Basin.

Coalbed-methane exploration in Washington had been dormant since the 1980s, but a revival appears imminent. Methane Energy Corp. (MEC) has begun drilling in three pilot areas with encouraging results so far. An engineering consulting firm thinks there may be as much as 1.2 trillion cubic feet in place within MEC's leasehold.

Gas production has grown for 10 consecutive years in Wyoming, and much of the credit goes to CBM development. The state now projects that CBM output from the Powder River Basin will grow from about 350 billion cubic feet in 2006 to as much as 400 billion cubic feet by 2010—and possibly to 400 billion cubic feet by 2011. New CBM drilling in Carbon County's Atlantic Rim area will add to the growth from traditional areas.

Already there are 72 operators of record in the state's CBM play, but more companies are adding to their positions through acquisitions and joint ventures. Tulsa-based Williams Production RMT remains the most active firm in the Powder; it planned to have drilled up to 440 CBM wells in 2006.

Handling the vast quantities of water produced along with the gas remains a key concern in most CBM plays, but especially in Montana and Wyoming, where groundwater quality varies across the basin, from potable to being too saline. The two states disagree on how best to comply with federal clean water regulations, and it isn't clear which federal agency has jurisdiction to settle this dispute.

Without question, the cost of water handling deeply affects internal rates of return, especially if gas prices go below $4 per thousand cubic feet, or if operators have to drill more injector wells alongside their producing wells.

Here you'll read more about a study performed by Advanced Resources International on this important issue.

It's one more way the editors hope to increase your understanding of the exciting potential and the challenges inherent in CBM production.

—Leslie Haines, Editor-in-chief

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Coalbed Gas Plays, West and East—A Study in Contrasts

Developers in the Pacific Northwest and Northern Appalachia are tackling new and overlooked coalbed-methane prospects with innovative production strategies tailored for their markets.

By Stephen D. Schwochow

For many years, the western frontier of coalbed-methane (CBM) development seemed to have progressed no farther than the Uinta Basin. Why? First, there's not much coal between Price, Utah, and the Pacific Coast. Second, what coal is there is an elusive target.

The most extensive coal deposits are found in Washington and Oregon (Figure 1). They accumulated with fluvial, deltaic and estuarine sediments and interbedded volcanics comprising the Puget Group on an ancient subtropical coastal plain, in reality a forearc basin, during Eocene time, about 47- to 39 million years ago. Gradually, the sediments were overrun by great outpourings of volcanic rock from eruptive centers along a magmatic arc that eventually became the Cascade Range.

Tectonic plate interactions have left the coal deposits scattered across the Puget Lowlands and Coast Ranges in comparatively small, genetically similar but structurally disparate sub-basins, making the region one of the most challenging coalbed-methane plays. Where coal measures aren't covered by volcanics, they can lie buried beneath a thick mantle of glacial outwash or masked by dense vegetation.

Coals found near the surface were mined beginning in the 1850s, and the underground workings reveal much of what geologists know about the intricate structure and the nature of the coals themselves, including the presence of gas. Indeed, it was the documentation of methane-related mine incidents and the famous "Flaming Geyser" phenomenon at a 1911 well site in King County that first attracted Amoco and a number of independents to explore for CBM gas in western Washington in the 1980s.

Despite finding an adequate number and thickness of coal seams, favorable coal rank and gas content, none of the ventures achieved commercial status, hindered mainly by structure-related wellbore completion problems and insufficient reservoir characterization.

One venturer persisted, however. Steve Pappajohn had long been involved with gas exploration in the region, first with Amoco and later through his Seattle-based consulting firm, GeoTrends Inc. Pappajohn had worked on several Washington projects before co-founding Carbon Energy International in 1992 to explore a bypassed prospect, the Coos Bay coal basin, in Coos County on Oregon's southern coast.

The fact that this basin covers only about 300 square miles may have factored into why it was not more vigorously pursued.

Carbon Energy drilled two tests there in 1993 targeting sub-bituminous to high-volatile bituminous coal seams in the 6,600-foot-thick Coaledo formation. Pipeline-quality gas was found, but production wasn't deemed viable at the time, and the effort was suspended.

The outlook changed later in the 1990s with the advent of improved completion and stimulation technologies and plans to bring natural gas service to Coos County. Moreover, gas demand was growing in the region where, after a century of exploration, no more than a whiff of natural gas production of any kind had been established—only at northern Oregon's Mist Field, and that has now been largely converted to gas storage. Essentially, interstate pipelines from western Canada and the Rocky Mountains must deliver all the gas consumed in the Pacific Northwest.

The time seemed right for a return to Coos Bay. Pappajohn teamed up with another ex-Amoco geologist, George Hampton of Denver, who also saw the possibilities there. They formed GeoTrends-Hampton International LLC (GHI) in 2000 to purchase the leases Carbon Energy formerly held.

In May 2004, Pappajohn and other associates formed Methane Energy Corp. (MEC), which became the operating subsidiary of Vancouver-based Scarab Systems Inc., later renamed Torrent Energy Corp. Their objective was to acquire GHI's leases and technical data for the original prospect as well as other coalbed leases that had been let by Coos County in 2002 but undeveloped by the lessee. During the years, Coos County had come to inherit some 48,000 acres of coal lands largely through mine abandonments and foreclosures.

NEW LEASING AND PILOT WELLS

MEC then began aggressively acquiring leases over other prospective areas, building toward a target leasehold of 100,000 acres. Since the area had not seen any conventional exploration since 1980, MEC was able to pick up mineral rights at prices as low as $1 an acre.

An exhaustive pre-exploration geologic and geophysical appraisal program identified sites for five coreholes, which were drilled between November 2004 and May 2005. Samples

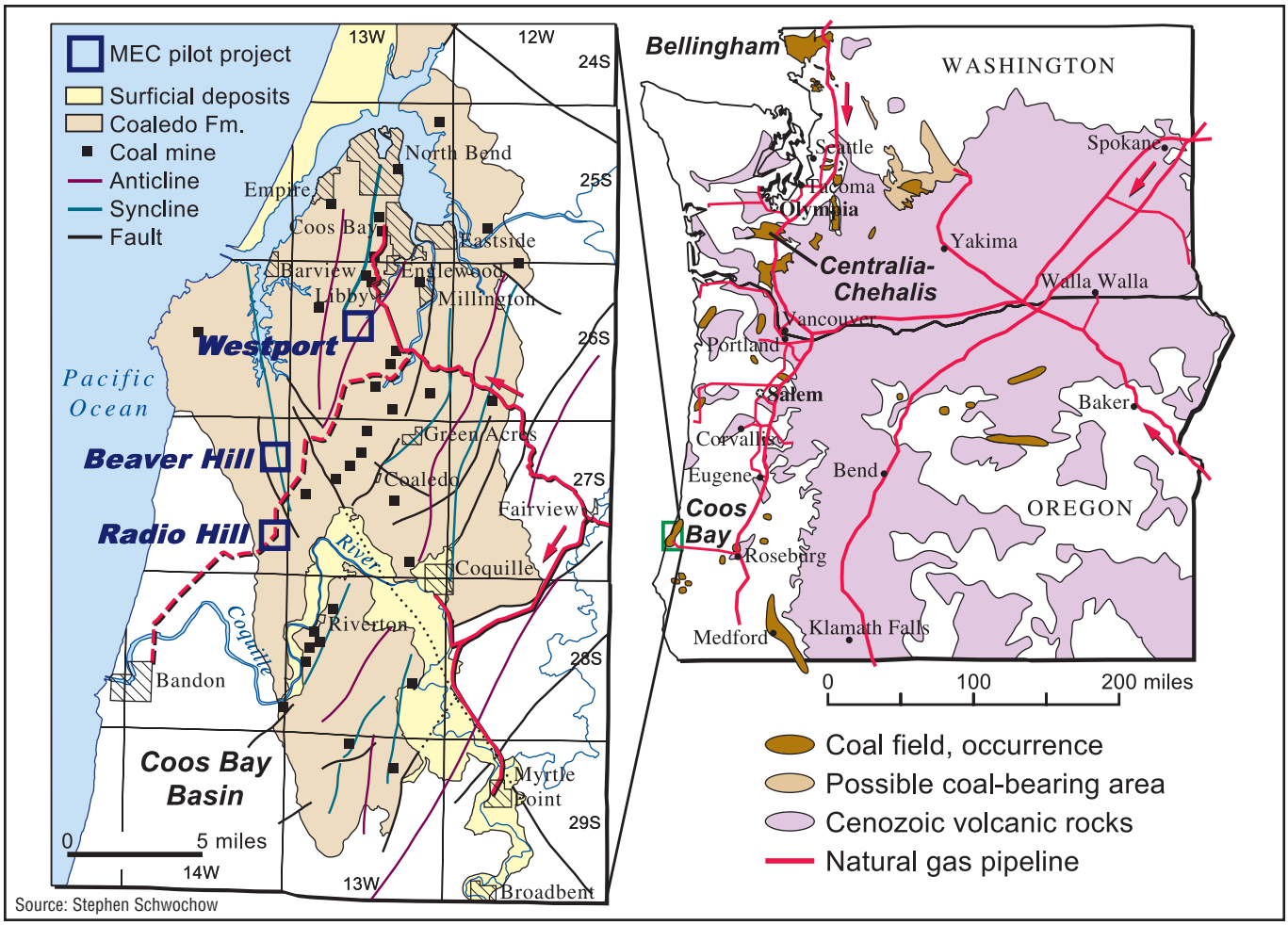


Figure 1. Coal fields of the Pacific Northwest and Torrent Energy's Coos Bay Basin project site.

from 11 coal seams were analyzed for gas content, rank, gas characteristics and other parameters.

Based on those tests, the Beaver Hill corehole site was selected for the first multiwell pilot project. After the corehole was cased and converted to a production well and tested, four additional wells were directionally drilled from the same pad, all penetrating multiple Lower Coaledo seams at depths of 4,200 to 4,400 feet. Part of the 15-foot-thick target "D" seam in each was stimulated with nitrogen through coiled tubing.

Results of initial post-stimulation testing this year have exceeded expectations—more than 200,000 cubic feet per day from each of three of the directional wells and more than 500,000 from the other. At present, all gas from the ongoing tests is flared.

Meanwhile, the company is evaluating the feasibility of completing additional coal zones uphole and testing alternative stimulation designs to optimize completion procedures for future wells.

Only one well was completed and tested at the second project site, Radio Hill, where 10 Lower Coaledo seams were nitrogen-stimulated. This well achieved sustained gas production rates averaging 30,000 cubic feet per day with only four or five barrels of water from 35 feet of net coal between 2,735 and 3,950 feet.

In October 2006, MEC commenced its third pilot at the Westport corehole site. This eight- to 10-well program, which will extend into next year, will test upper and lower Coaledo coals at much shallower depths (1,500 to 3,000 feet).

The encouraging test results naturally raise the question of how much gas might be available. An assessment by Sproule Associates Inc. indicates 1.2 trillion cubic feet (Tcf) of coalbed gas in place within MEC's leasehold, which now totals 116,000 acres.

That assessment could rise, depending on the degree of water saturation in the coal cleat system. So far, the pilot wells have produced unusually low water volumes for CBM operations. The low yields suggest a substantial free-gas component might exist in the reservoir, meaning water production could be minimal and water disposal will not be a critical issue. This supposition has not yet been confirmed, however.

While MEC has worked to build strong local support for its efforts, some residents and outside-influence groups fear a Powder River Basin scenario for Coos Bay, with dire consequences for streams, springs and the local salmon population.

In reality, impermeable strata hydraulically isolate the water in the deep Coaledo coals from the shallow

fresh-water aquifers that supply households and feed streams. Still, MEC has volunteered to assist the Oregon Department of Geology and Mineral Industries with surface and groundwater-quality studies.

At the Westport project site, MEC will evaluate potential horizons for water disposal in fractured basalts that underlie the Coaledo formation. For now, produced water is trucked to a dilution facility adjacent to the municipal water-treatment plant in Coos Bay.

The Oregon Department of Environmental Quality will require an approved water disposal/containment plan for any commercial-scale project. Ground-surface discharge will not be an option.

TRANSPORTATION

Until recently, Coos Bay had been one of the West Coast's largest population centers without natural gas service. After years of planning and a plethora of construction problems and delays, not to mention a price tag of $51 million, Coos County finally opened its first gas pipeline in January 2005.

The 12-inch pipe runs about 60 miles from Northwest Pipeline's interstate line at Roseburg into a local distribution network built and operated by Northwest Natural Gas, the region's largest gas utility. The line presently serves Coos Bay and North Bend, with laterals to Myrtle Point and Coquille, the county seat. Officials expect the pipeline to be a boon for the local economy, as it already has attracted new industrial gas customers to the area.

MEC expects eventually to deliver its gas into this system for sales—the pilot projects are situated relatively close to the existing lines. Until then, the company is assisting Northwest Natural Gas and Coos County in attempts to move forward with a third, as-yet unbuilt lateral, to Bandon, Oregon, that is in litigation. An alternative route for that pipeline along U.S. Highway 101 would afford an optimal tie-in opportunity.

Among interim plans that could help monetize at least some of MEC's currently "stranded" gas is liquefaction at the well sites with delivery to local markets via tanker trucks.

One can look to a number of factors that have contributed to the success of the Coos Bay project to date:

- A competent technical staff with extensive geological, geophysical, engineering and environmental experience.
- Aggressive approach to leasing.
- Year-round access on maintained public, logging and fire-control roads.
- Availability of timber-recovery staging areas for the initial drillsites.
- Contracting with one drilling company for all the pilot wells.
- Active outreach program that has garnered strong support from local, regional and state agencies and organizations.

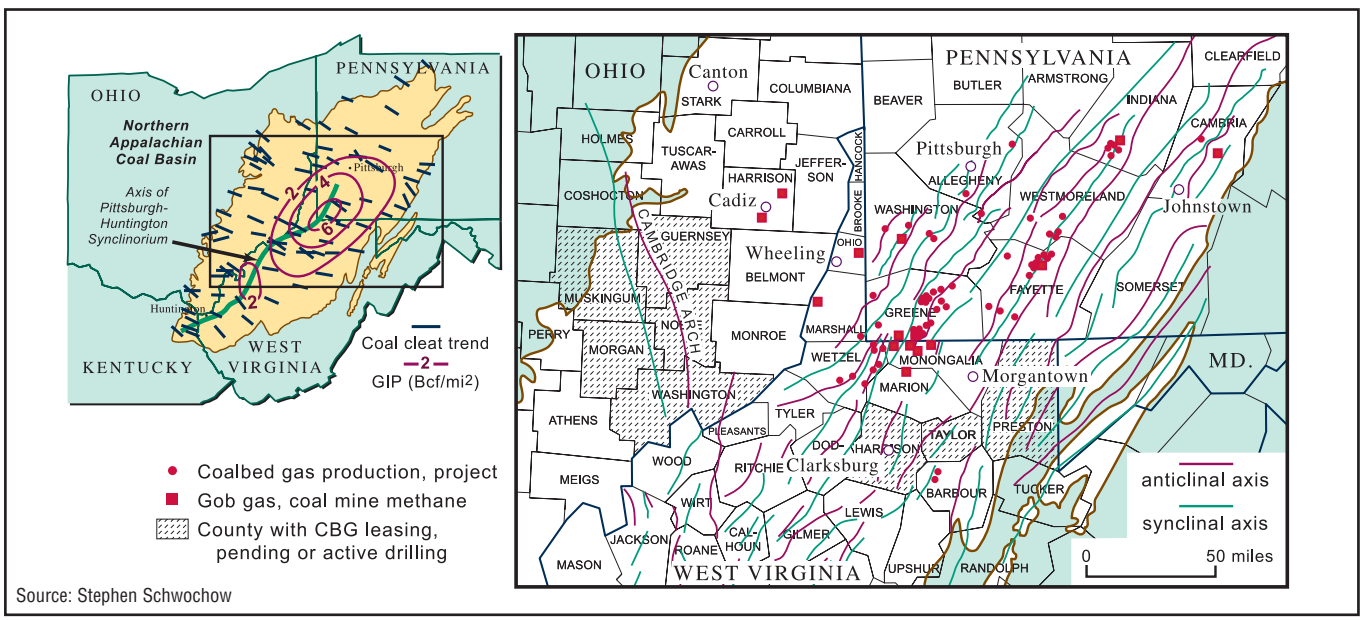
Of no less importance have been the ongoing efforts by Torrent's principals in having raised $45 million in operating funds and working capital.

As the true reserves potential continues to be proved up, Torrent believes the time is approaching to consider finding a joint-venture partner who could help transition the project into full field development.

BACK TO WASHINGTON

Torrent Energy also is planning to give southwestern Washington a serious look. Its other subsidiary, Cascadia Energy, has leased more than 130,000 acres of private and state lands in Lewis, Cowlitz and Skamania counties. The holdings lie east of the Centralia-Chehalis district, Washington's largest subbituminous coal field and site of the state's largest open-pit mine and thermal power plant.

Cascadia's joint-venture partner, St. Helens Energy LLC (a subsidiary of Comet Ridge Ltd., an Australian coalbed gas explorer), will operate the project and hold a 40% interest. Initial work will consist of drilling stratigraphic tests and coreholes targeting a dozen or more seams in the Skookumchuck and Cowlitz formations, as well as possible conventional-gas horizons.



Source: Stephen Schwochow

Figure 2. Coalbed gas in the Northern Appalachian Basin.

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NORTHERN APPALACHIAN BASIN

The Pennsylvanian stratigraphic section of the Appalachian region is remarkably rich in coal—40 to 50 named seams, of which 10 to as many as 20 may be viable gas targets in a given area.

Despite holding an estimated in-place resource of 61 Tcf, the Northern Appalachian coalbed gas play, which extends across western Pennsylvania, northern West Virginia and southeastern Ohio, has been considerably slower to develop than the Central Appalachian play in western Virginia and southern West Virginia.

Although the northern play is expanding, the area has produced barely 15 billion cubic feet (Bcf) since 1988, from an estimated 160 active wells. In contrast, cumulative production from the Central Basin, with 5 Tcf in place, stands at 676 Bcf. Annual production for last year topped 85 Bcf from 3,100 wells, mostly in Virginia.

In the north, the distribution of established production shows a close association with conventional gas-productive structures of the Pittsburgh-Huntington synclinorium. Well productivity appears highly dependent on enhanced fracture permeability—fold-induced extensional fracturing overprinted with nearly orthogonal coal face-cleat and other regional fracture trends.

This seems to be reflected in the distribution of the resource, which, according to studies by the U.S. Department of Energy (DOE) and the Gas Research Institute, is concentrated in an elliptical bulls-eye pattern over the deepest part of the basin (Figure 2).

Coalbed-gas production from the Northern basin dates from 1932 at the Big Run gas field in northern West Virginia, where wells were recompleted in the Pittsburgh coal, a dangerously gassy seam well known to miners. Pine Grove oil field was another redeveloped as a coalbed-gas field in the 1950s.

Through the early 1980s, many attempts were made, with some success, to commercialize coalbed gas as outgrowths of U.S. Bureau of Mines research and DOE-sponsored programs. Some focused on mitigating methane hazards in underground mines, while others sought to capture methane for small-scale power generation or local gas supply.

TECHNICAL ADVANCES

With the advanced technologies available, an array of successful production options has evolved.

Longwall mine operators, for example, are making greater use of methane drained through networks of in-seam degasification boreholes. Methane also is recovered from abandoned mines and worked-out sections of active mines through "gob wells" and conversion of mine-ventilation boreholes.

Dominion operates numerous gob wells and converted ventholes around Consol's Blacksville No. 2 Mine. At another, Noumenon Corp. blends gob gas with high-Btu natural gas or "spikes" it with propane to meet pipeline specifications. The company sells the upgraded gas to utilities and a local glass manufacturer.

Vertical multiseam wells are common in areas of "virgin" or deep, nonmineable coal and where coals can be degasified to some extent in advance of mining. From three to as many as 10 seams may be completed and fracture-stimulated in a given well.

The Appalachians also have become a showcase for horizontal and multilateral drilling. CDX Gas LLC has achieved impressive results with its Z-Pinnate technology on Penn Virginia's property in southern West Virginia. It is now developing multilateral patterns for CoalQuest Development LLC in Barbour County and has recently acquired leases in Westmoreland County, Pennsylvania. Dynatec Corp. is testing a variation of horizontal technology that involves pairs of intersecting horizontal and vertical wells.

CNX Gas Co. LLC is doing a little of everything—gob wells, borehole conversions, multiseam completions, and two- and three-leg "turkey foot" horizontal wells. The company also has announced plans in Pennsylvania for a dedicated coalbed-gas processing plant and a major new exploration effort on 548,000 acres. CNX is the gas-operations spinoff of coal-mining giant Consol, which had become the Appalachia's largest coalbed gas producer through aggressive development at its mines and coal properties in Virginia.

OHIO CBM OUTLOOK

Industry finally has begun taking a closer look at southeastern Ohio. According to the Ohio Geological Survey, a little coalbed gas was produced as early as 1924 in Carroll County. Some conventional gas appears to have been sourced from deeper coalbeds as well, such as that in the shallow "Salt Sands." Ten to 24 seams are present in the coal measures that underlie about 10,000 square miles.

A possible reason for the disinterest might be the perception that much of the entrained gas has escaped as a result of the deeply dissected topography and Ohio's updip structural position on the basin flank. Larry Wickstrom, supervisor of the Survey's Petroleum Geology Group, conservatively estimates an average gas content of 57 standard cubic feet per ton, but that's based on only scant and not entirely reliable desorption values. Nevertheless, the survey estimates 5 Tcf of gas in place and 2 Tcf recoverable from just five of the coalbeds it has studied.

The longest running coalbed venture in Ohio doesn't actually produce directly from a coal seam, but rather taps methane accumulated in an abandoned mine. Northwest Fuel Development Inc. of Portland, Oregon, has since 1993 generated electricity with gas engines fueled with a methane-air mixture drawn from the Nelms No. 1 Mine near Cadiz, Harrison County.

Not far away, a second Northwest Fuel project, funded in part by the DOE, was dedicated in 2003 at the Rose Valley Mine near Hopedale. This $7-million demonstration featured the world's first fuel-cell-powered by mine methane, a 200-kW molten-carbonate unit designed by FuelCell Energy Corp. of Danbury, Connecticut. The

plant ran on 55,000 to 80,000 cubic feet per day of gas containing only 42% to 47% methane.

Wickstrom also found that converted ventholes at the Nelms mine have been steadily flowing 2 million cubic feet of gas per day, suggesting not just methane-air is being drawn, but also in-situ methane.

If true, that should offer some encouragement. One company has begun what could lead to a comprehensive pilot program for Ohio. Dallas-based Harken Energy Corp., through subsidiary Gulf Energy Management Co., has partnered with Ohio Cumberland LP of Texas to explore a 400,000-acre area of mutual interest that stretches across Guernsey, Morgan, Noble, Muskingum and Washington counties. Gulf Energy, which is providing $7.5 million for the initial exploratory phase, will have a 65% working interest and receive an 82.5% net revenue interest.

In November 2005, Harken entered a similar agreement with Ohio Triangle LP for another phased investigation, this one on some 20,000 acres.

By the end of that year, Ute Energy, the contracted driller and operator, had completed three coreholes. As of press time, coal samples were still being analyzed, and Harken had announced no decision regarding a go-ahead for pilot drilling.

Thanks to decades of drilling by the coal and oil and gas industries, Appalachia offers added benefits of abundant subsurface control and a dense gas-transportation infrastructure that serves a high-demand area. Beware, however, of the highly fragmented mineral estate, which continues to frustrate developers on two fronts.

First is the increasingly contentious issue of surface-owner versus mineral-owner. As a case in point, Salem township officials in Westmoreland County, Pennsylvania, enacted an ordinance in 2005 to give surface-owners greater control over access and construction activities by coalbed-gas-owners.

Their action was prompted by a proposal for 200 new gas wells on 8,000 acres owned by Great Lakes Energy Partners, a unit of Range Resources Corp. In September, the ordinance was struck down in a common pleas court as a usurpation of the Oil and Gas Act of 1984, the state's primary regulation that governs drilling operations.

Second, who owns the coalbed gas—the coal owner or the oil and gas owner? It all depends. Legal precedents for establishing ownership of coalbed gas in Appalachia have considered a number of criteria and, consequently, vary from state to state. So, one will need a good landman. •

Stephen Schwochow is an author and geological consultant based in Golden, Colorado.

Powder River Basin CBM Production Still Growing

Wyoming coalbed-methane producers are jockeying for position as production rises. Here's a look at several key players.

By Gary Clouser, Contributing Editor

Acquisitions and agreements are changing the identities and rankings of coalbed-methane (CBM) producers from the Wyoming side of the prolific Powder River Basin (PRB), even as activity on the Montana side stalls because of regulatory uncertainty.

The Wyoming Oil and Gas Conser-vation Commission projects that for this year, an estimated 2,900 wells will have been drilled and production will be about 350 billion cubic feet (Bcf). That would top the previous annual high of 346 Bcf set in 2003, says Don Likwartz, oil and gas supervisor.

Last year, there were 72 operators in the Wyoming portion of the basin and 2,895 wells were drilled. Coalbed-methane production from the Wyoming side in 2005 was 336 Bcf, Likwartz says.

The state projects that annual CBM production from the PRB will grow to 400 Bcf by 2010 and 500 Bcf by 2011.

Coalbed-methane development in northern Wyoming totals about 12,500 square miles and includes all of Campbell, Sheridan and Johnson counties as well as the northern half of Converse County. These are the focus of much of the deal-making.

Rig and skilled-crew availability has become an issue. Last year, the average daily rig count in the PRB was 53, but, during the first seven months of this year, it slipped to 43. It is difficult to get rigs and crews for CBM use because of the competition resulting from the highest number of conventional oil and gas rigs operating since 1985, Likwartz says.

Leading Wyoming CBM producers—Anadarko Petroleum, Pennaco Energy (Marathon Oil) and Bill Barrett Corp.—closed transactions intended to enhance their production volumes, while Storm Cat Energy's deals are likely to propel it into the top tier.

WILLIAMS RMT CO.

The most productive Wyoming CBM producer in the PRB is Williams Production RMT Co., a subsidiary of The Williams Cos. of Tulsa. It produced 62.4 Bcf from 2,717 wells last year. Its production as of June 30, 2006, was 257 million cubic feet a day, according to spokesman Kelly Swan.

Williams RMT operates 3,000 producing wells in the basin and is expected to have drilled about 440 CBM wells in the basin this year, at a cost of $125 million. For next year, the company expects to drill about 450 CBM wells and have a capital expenditure of $130 million. Williams projects that by year-end 2007, its CBM production from the basin will be about 300 million cubic feet a day.

"We think the CBM play in the Powder is a great story right now, because of the rapid growth coming from the Big George coals," Swan says.

ANADARKO PETROLEUM

The second-ranked Wyoming CBM producer for 2005, Lance Oil & Gas Co., has been acquired by Anadarko Petroleum as part of its larger acquisition of Western Gas Resources. That deal closed in August.

"The Western Gas transaction enhances our ability to deliver stronger and more predictable results by bolstering our portfolio of low-risk, long-lived tight-gas and coalbed-methane resource plays in the Rockies," Anadarko chairman, president and CEO Jim Hackett said when the deal was announced.

With the addition of Western Gas Resources' CBM properties within the PRB, Anadarko now has an estimated gross resource potential of 4.8 trillion cubic feet (Tcf) in the PRB.

Anadarko also acquired Western Gas Resources' 10% average working interest in its Pinedale/Jonah joint ventures, which encompass world-class fields totaling more than 40 Tcf of gas. Anadarko expects that combining its properties and skill sets with Western Gas' will accelerate development of these gas resources and produce strong volume growth through the end of the decade, and possibly longer, with more than 12,000 identified drilling locations in inventory. Anadarko Petroleum Corp. ranked seventh last year in Wyoming CBM production with 18.1 Bcf.

STORM CAT ENERGY

Storm Cat Energy's acquisition of reserves from Bill Barrett Corp., coupled with its agreement with Pennaco Energy, a subsidiary of Marathon Oil, is certain to propel it toward the top of the rankings.

Storm Cat, a rapidly growing exploration company focused on developing unconventional natural gas resources, has ramped up its activities in the Powder River Basin since acquiring its initial position in

Installation of Scotch compressor station. (Photo courtesy of Bill Barrett Corp.)

December 2004. The company expects to drill 91 PRB wells in 2006. For the year, its basin spending is an estimated $48.2 million, which includes acquisitions of $31 million.

This past summer, the company acquired 17,030 net acres from Bill Barrett Corp.

J. Scott Zimmerman, president and CEO of Storm Cat, says that as of September 1, the company had 39,235 gross acres leased in the PRB and 66 Bcf of unrisked reserves potential. Its current net daily rate of production from the PRB is 7 million cubic feet equivalent (MMcfe). Average production this year is 4.2 MMcfe, compared with its 2005 daily average of 2.5 MMcfe.

Pennaco and Storm Cat have established an area of mutual interest (AMI) in which Storm Cat will act as operator. The company is acquiring an undivided 50% of Pennaco's working interest and production in existing wells, leasehold and infrastructure, and will have the option to earn an undivided 50% interest in Pennaco's leasehold within the AMI through development.

Zimmerman notes the agreement provided Storm Cat with an opportunity to acquire additional PRB leasehold adjacent and contiguous to its existing development project in the core Northeast Spotted Horse operating area in Campbell County.

The gathering assets and existing infrastructure included in the AMI are one example of how Storm Cat can benefit by expanding its core area.

"Like the recent transaction with Bill Barrett Corp., the JDA [joint development agreement] is an extension to our current asset base and provides a foundation for future reserve and production growth in the area," he says.

Storm Cat closed on the $30.7-million Powder River Basin acreage purchase from Bill Barrett Corp. effective July 1. It has an approved Federal Plan of Development (POD) for 38 wells on this acreage with 25 to be drilled by year-end. To further develop the acreage, application is being made on two PODs for next year. A total of 145 locations are anticipated for drilling to fully develop the Barrett acreage.

"The acreage from Bill Barrett is approximately 81% undeveloped, and 90% of the acreage is located on U.S. federal lands. Storm Cat is acquiring approximately 10.2 Bcf of proved reserves, 9.6 Bcf of probable reserves and 7.8 Bcf of possible reserves. Gas production from the acquired properties is approximately 6.6 million cubic feet a day, (approximately 3 million cubic feet net), of natural gas from 64 producing CBM wells, 46 of which will be operated by Storm Cat. As of

Trinity Exploration Pathfinder rig is drilling the Daly Federal 09CW-12 52-74 in Campbell County, Wyoming.
(Photo courtesy of Storm Cat Energy Corp.)

September 2006, CBM production from the property acquired from Bill Barrett had a daily average of 2.8 MMcfe," Zimmerman said at the time of the deal.

Storm Cat will use the multi-seam completion technique that provides for increased recovery and reduced finding and development costs.

The company has executed its strategy beyond the PRB by acquiring undeveloped leasehold in three additional areas: 78,000 acres exploiting the Mist Mountain coal seam potential and about 18,000 acres with potential from the Manville coals where it just completed its first well (both in Canada); and an 18,000-acre entry into the promising Fayetteville Shale play in Van Buren County, Arkansas.

BILL BARRETT CORP.

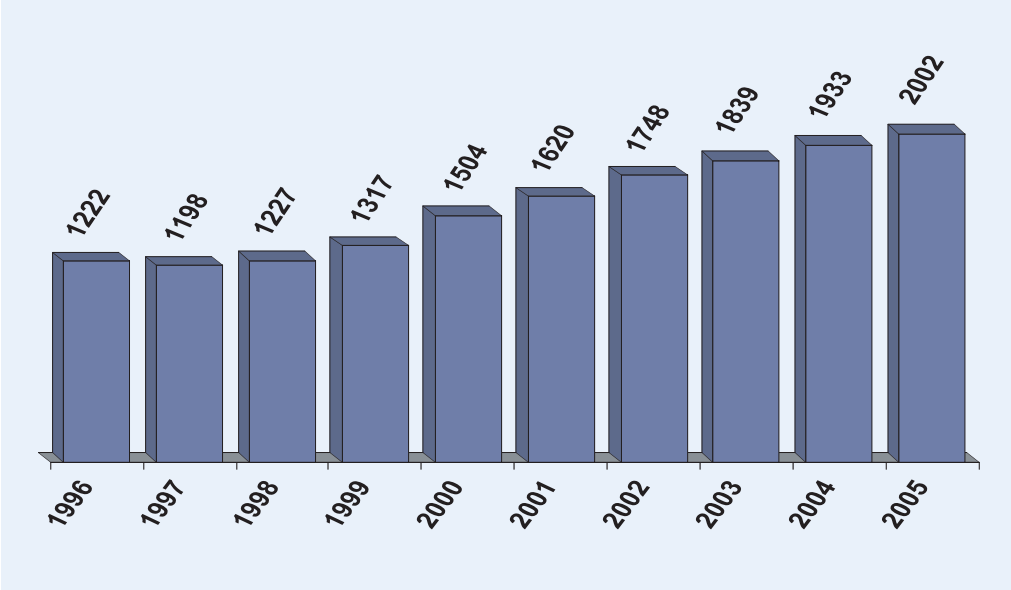
Bill Barrett Corp., which ranked eighth in Wyoming CBM production last year with 14.1 Bcf, has been a buyer and seller of PRB property as well. It sold property to Storm Cat and bought CH4 this year. The result was an overall increase in its PRB acreage and a concentrated effort on the Big George coals.

In May, it closed on the $80-million purchase of CH4, a Fort Worth, Texas-based portfolio company of Natural Gas Partners. CH4 had about 85,000 gross (51,900 net) undeveloped acres in the PRB and was producing 6 million cubic feet a day from 163 wells. Another 128 wells were in progress or dewatering at the time of closing. Estimates of proved reserves were 11 Bcf and probable and possible were at least 50.4 Bcf. Future development costs were estimated at $44.5 million.

Chairman and CEO Fred Barrett says this deal provides greater critical mass and efficiencies in the Powder River Basin.

"In addition to proved, probable and possible reserves, we believe there may be further potential with multi-seam completions and the completions of secondary coals. Our subsequent divestiture to Storm Cat proves us the opportunity to focus on operations on Big George coals, which provide strong rates of return," he says.

Bill Barrett Corp. has 122,000 net acres and 25 Bcf of proven reserves and is producing a net 18 million a day. The company has potential for more than 900 gross drilling locations, primarily in the Big George coals, and expects between 200 and 300 wells will be drilled annually.



Gas production for Wyoming, measured in billion cubic feet per year, has been on a steady incline for the past 10 years. (Graph courtesy of Wyoming Oil and Gas Conservation Commission)

Joe Jaggers, president and CEO, says the company expects its PRB CBM production will continue to see double-digit growth.

Production has grown at a 56% compound growth rate from 2003 through 2005. At 18 million cubic feet a day, volumes are down from last year because of the many wells still in the dewatering stage, which Jaggers says can take from a few months to nearly two years. Eventually, as the water production decreases, gas desorbs from coals and the well begins to produce gas. Thus, production growth can be "lumpy" depending on the number of wells dewatering, he says.

MARATHON OIL

Pennaco was founded in 1988 to focus on CBM production from the PRB, but Marathon Oil acquired it in 2001 for $500 million. At that time, Pennaco added 200 Bcf of proven gas reserves and more than 800 Bcf in upside potential to Marathon's portfolio.

Today, Marathon's production of

CBM in the Powder is done under the banner of its subsidiary, Pennaco Energy. Its 2005 Wyoming CBM production was 29.7 Bcf from 2,148 producing wells, according to the Wyoming Oil and Gas Conservation Commission, ranking it fifth in Wyoming CBM production last year.

Through the first nine months of this year, Pennaco was producing at a net rate of 75 million a day from about 3,300 wells, says Marathon spokesman Paul Weeditz.

The company's position here is about 300,000 acres, nearly all of which is in Wyoming—the company sold most of its Montana acreage to concentrate on the Wyoming side. The agreement with Storm Cat covers about 10,000 acres, he says.

Marathon further expanded its PRB assets by about one-third in May 2002 as a result of the acquisition of the assets owned by its major partner in the basin, XTO Energy Inc. That deal added more than 400 Bcf of PRB resources to Marathon's portfolio, including 110 Bcf of proven reserves.

"Wyoming has been a core area of conventional oil and gas operations for us for over 95 years. Coalbed natural gas development is a new element of our Wyoming portfolio. Our production from the PRB has continued to evolve and grow as we have applied our technology and expertise to help realize the full potential of this important resource basin," Weeditz says.

TOP 25 WYOMING CBM OPERATORS

Williams Production RMT Co.	62.4 Bcf
Lance Oil & Gas Co.	41.4 Bcf
JM Huber Corp.	35.2 Bcf
Devon Energy Production	35.1 Bcf
Pennaco Energy	29.7 Bcf
Yates Petroleum	29.7 Bcf
Anadarko Petroleum	18.1 Bcf
Bill Barrett Corp.	14.1 Bcf
Fidelity E&P	8.3 Bcf
Coleman Oil & Gas	7.5 Bcf
Petro-Canada Resources (USA)	6.7 Bcf
Pinnacle Gas Resources	5.7 Bcf
Merit Energy	5.2 Bcf
Kennedy Oil	5.1 Bcf
Primary Natural Resources	4.3 Bcf
Hilcorp Energy	4.1 Bcf
Petrox Resources	2.6 Bcf
Windsor Energy Group	2.2 Bcf
Double Eagle Petroleum	2.1 Bcf
Anadarko E&P Co.	2.0 Bcf
Emerald Operating Co.	1.7 Bcf
Warren E&P	1.5 Bcf
Majestic Petroleum Operations	1.4 Bcf
Rocky Mountain Gas Inc.	1.3 Bcf
Peabody Natural Gas LLC	1.1 Bcf

Total Wyoming CBM production for 2005 was 340.6 Bcf.

CBM production accounted for 17% of the state's total gas production in 2005.

Source: Wyoming Oil and Gas Conservation Commission

FIDELITY E&P

Fidelity E&P, a subsidiary of MDU Resources, is another top-10 Wyoming CBM producer. It ranked ninth last year with production of 8.33 Bcf from 746 wells. Terry Hildestad, president and CEO of MDU Resources, says Fidelity's current CBM production is about 55 million cubic feet a day, and that it would drill 150 CBM wells this year.

Even when natural gas prices slipped in late summer and early fall from earlier peaks, analysts said they expected no slow down in the pace of Wyoming CBM drilling. There is no direct evidence of CBM drilling being delayed, says Wood Mackenzie analyst Andrew Strachan.

"It tends to be the marginal high-cost plays that get affected first rather than CBM plays. We view the dip in prices as being short term, with the Rockies basis being amplified by short-term pipeline issues," he says.

Mike Caskey, executive vice president and chief operating officer of Fidelity E&P, agrees, but says the impact of the $1- to $1.50 price discount per thousand cubic feet of Wyoming CBM compared with Nymex prices (in part because of infrastructure issues) is magnified as prices decline, as is the variable cost of water management methods.

State officials also see no slowdown. In fact, they project a widening of the geographic area that will draw drillers. While the PRB is unquestionably the hub of Wyoming's CBM activity, the state's Likwartz says there are indications that the Atlantic Rim in southwest Carbon County could become the next major CBM development in Wyoming. The state projects 100 wells will be drilled in that area this year and produce just 2 Bcf; but by 2010, the number of wells drilled will be 200 and production will be 100 Bcf. •

WATER MANAGEMENT A KEY CONCERN

Using the right water-handling techniques can determine economics and recoverable volumes of coalbed methane in the Powder River Basin.

By Gary Clouser, Contributing Editor

How much more coalbed methane (CBM) can economically be recovered from the Powder River Basin, and how will the environmentally sensitive issue of water disposal be handled? The answers to those questions are interwoven.

Those two questions formed the idea for a recent U.S. Department of Energy study, *The Economics of Powder River Basin Coalbed Methane Development*, conducted by Advanced Resources International.

"The more stringent and costly the water management option, the less of the CBM resource in the basin that will be economic," according to the study.

The capital costs for alternative CBM water disposal options add $1,500 to $72,300 per well, depending on the water management practice selected.

Disposal of water is one of CBM development's biggest challenges, not just in the Powder River Basin (PRB), but also in other CBM plays. Fractures in coal are typically saturated with water, and the coal must be dewatered, or pumped out, before the gas will flow. Discharges from CBM wells typically contain sodium and sometimes other dissolved minerals. Environmentalists claim CBM development affects underground water quality and contaminates aquifers. Groundwater may be contaminated by mineral-tainted discharged water, they also say.

Assuming $4 per thousand cubic feet at the wellhead (roughly equivalent to a

Nymex price of $5.70 per thousand cubic feet), and a 15% rate of return, some 17,070 billion cubic feet (Bcf) are economically recoverable, with surface discharge of produced water, according to the study. That is the most common method, but it has come under increasing attack from environmentalists.

However, with impoundments and infiltration of produced water (a more costly option than surface disposal), the economically recoverable estimate falls by 1,390 Bcf. It falls further still with shallow re-injection of produced water. That estimate is 2,160 Bcf less than with surface discharge, or an estimate of 14,910 Bcf.

More complex and expensive solutions would involve reverse osmosis or ion exchange. Those options were examined under two water-quality effluent limitations of 500 parts per million (ppm) of total dissolved solids (TDS) and 1,000 ppm TDS. Dissolved solids refer to any minerals, salts, metals or ions dissolved in water. An ion is an atom or group of atoms that has an electric charge by losing or gaining one or more electrons. When TDS levels exceed 1,000 milligrams per liter (mg/L), it is generally considered unfit for human consumption. Most often, the presence of potassium, chlorides or sodium cause high levels of TDS.

With reverse osmosis, produced water passes through a semi-permeable membrane that filters out dissolved solids and various ions. The cleaned effluent is then discharged while the residual concentrate is trucked to a disposal facility, according to the study. At a TDS discharge limit of 1,000 mg/L, the economically recoverable volume is 14,960 Bcf, or 2,100 Bcf less than using surface

Water Disposal and Management Option	Economically Recoverable CBM (Bcf)	Reduced CBM Recovery Compared to Using Surface Discharge (Bcf)
1. Surface Discharge	17,070	-
2. Impoundments	15,680	1,390
3. Shallow Reinjection	14,910	2,160
4. Partial RO Treatment (w/Trucking of Residual)		
@ 500 mg/l TDS Discharge Limit	12,460	4,610
@ 1,000 mg/l TDS Discharge Limit	14,960	2,110
5. Ion Exchange		
@ 500 mg/l TDS Discharge Limit	14,090	2,980
@ 1,000 mg/l TDS Discharge Limit	15,940	1,130

**The above volume of economically recoverable CBM in the Powder River Basin is in addition to the approximately 1,530 Bcf of CBM produced and 2,360 Bcf proven through 2004.*

Source: *The Economics of Powder River Basin Coalbed Methane Development*, a study conducted by Advanced Resources International for the Department of Energy

Estimated economically recoverable Powder River Basin CBM at $4 per thousand cubic feet (Mcf) wellhead price ($5.70/Mcf at Nymex) and 15% IRR.*

Wellhead Price $/million Btu	Surface Discharge	Impoundments & Infiltration	Shallow Reinjection	Reverse Osmosis with Residual Trucking		Ion Exchange	
				TDS Limit: 1,000 mg/L	TDS Limit: 500 mg/L	TDS Limit: 1,000 mg/L	TDS Limit: 500 mg/L
	CBM Volume (Bcf)	CBM Volume (Bcf)	CBM Volume (Bcf)	CBM Volume (Bcf)	CBM Volume (Bcf)	CBM Volume (Bcf)	CBM Volume (Bcf)
3	13,420	11,110	10,100	9,530	6,390	11,240	8,210
3.50	15,520	13,610	12,780	12,880	9,210	14,060	11,820
4	17,070	15,680	14,910	14,960	12,460	15,940	14,090
4.50	18,240	17,460	16,980	16,660	14,440	17,450	15,880
5	19,480	18,410	17,840	18,060	16,740	18,450	17,560
5.50	20,810	20,030	19,360	19,400	17,860	19,980	18,340
6	21,440	20,820	20,610	20,550	19,120	20,850	20,210
6.50	22,640	21,840	21,560	21,490	20,320	22,020	21,090
7	23,280	22,790	22,500	22,230	21,660	22,520	22,120

Source: *The Economics of Powder River Basin Coalbed Methane Development*, a study conducted by Advanced Resources International for the Department of Energy

Estimated relationship of wellhead natural gas prices and water management practices to economically producible CBM from the Powder River Basin, assuming a 15% IRR.

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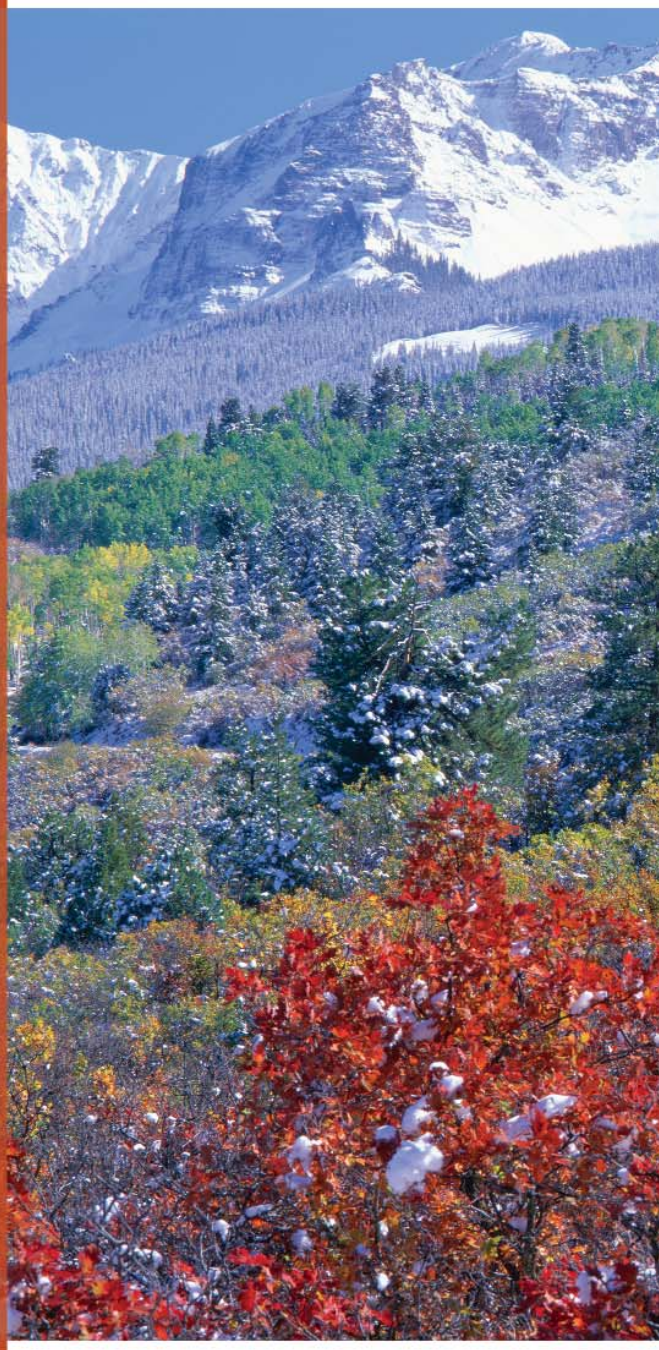

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Fidelity's Story

Fidelity E&P, a top producer from the Powder River Basin and the only Montana coalbed-methane (CBM) producer, has been at the center of the water-disposal controversy. It has been sued and counter-sued on the issue as its plans for CBM drilling on federal lands in Montana have been stalled for years because of litigation.

"Some folks consistently refer to the water produced from coalbed natural gas production as 'salty.' This is not an accurate characterization. In fact, the water produced from CBM gas production is closer to the technical definition of fresh water than it is to saline water," says Fidelity E&P president Darwin Subart.

Fresh water, as defined by the United States Geological Survey, is water that contains less than 1,000 milligrams per liter (mg/L) of total dissolved solids (TDS). The water produced at Fidelity's project near Decker, Montana, contains fewer than 1,500 mg/L of TDS, he says. According to USGS parameters, moderately saline water ranges from 3,000 to 10,000 mg/L; highly saline water ranges from 10,000 to 35,000 mg/L of TDS; and seawater averages about 35,000 mg/L of TDS. While the water produced at Fidelity's project may be rated "slightly" saline, it has less than half the TDS of "moderately" saline water.

"It is important to note that the groundwater quality varies significantly across the Powder River Basin," he says. "The fact is that the water meets established criteria for both human and livestock consumption and is not toxic to aquatic life. The only potential problem with the produced water is that it is generally not suitable for irrigation on clay soils without proper management. The water meets all of the primary drinking water standards for human consumption as established by the Environmental Protection Agency."

In most instances, ranchers who own land where CBM development is taking place are anxious to have additional water resources available, allowing them to spread out their cattle over more of the available range.

"Several ranchers have reported weight gain in their cattle in winter months because they had a readily available source of water," Subart says. "Some say that injection is a responsible method for produced water disposal (and pressure maintenance). Injection has been used in other parts of the U.S. However, when the water quality is usable, potable water, like the water produced with CBM in many parts of the Powder River Basin, it does not make sense to dispose of it."

In most instances, where the petroleum industry has used injection for disposal, the produced water quality is not beneficial. For example, in the San Juan Basin of southwestern Colorado and northwestern New Mexico, produced water has 10 to 30 times the TDS levels as in Powder River Basin CBM. "It is almost as saline as seawater," Subart says.

The water produced from the Williston Basin of eastern Montana and western North Dakota has 100 times the TDS levels seen in the PRB and five times the TDS levels of seawater. Produced water in the San Juan and Williston basins is disposed of by injection.

"Some say injecting produced water into the same coal zones eliminates/mitigates the full range of adverse surface water impacts. This statement ignores the other surface impacts of injection. First of all, you simply can't put all of the water back. Industry's experience with coals as injection zones suggests they are not very effective receptors of produced water. Therefore, to return the water to the coal, an operator would have to drill one injection well for every one to two producing wells. The thought of that many additional wells and the related infrastructure (i.e., injection lines, pumping stations, power lines, etc.) is staggering," Subart says. •

discharge. At a TDS discharge limit of 500 mg/L, the economically recoverable volume is 12,640 Bcf, or 4,610 Bcf less than using surface discharge.

With ion exchange, produced water enters the ion exchange unit where it contacts a strong acid-impregnated resin. The treated water is then discharged to a neutralized bed where residual bicarbonate ions can react with calcium. The water is then discharged into permitted discharge points.

ARI president Vello Kuuskraa, who along with Gregory Bank, also of ARI, authored the study, says two points stood out in his investigation. First, the PRB coals are two to three times wetter than in most plays. Second, the quality of produced water from the basin is better than in most CBM plays—produced water is being used in Gillette, Wyoming, as a source of drinking water, he says.

The ARI study has evoked the predictable response from environmentalists and producers, he says. Environmentalists say the study's estimated costs for water management are too high, while producers say, even if the technical obstacles could be overcome, the estimates are probably too low.

"We feel comfortable with our estimates, having spoken to a number of vendors," Kuuskraa says.

It is understandable that producers are concerned about water management costs because every dollar they spend on this is a dollar less that goes into their pockets, as there is a $1-to-$1 ratio, Kuuskraa says.

As natural gas prices slip and water management costs rise, it may become increasingly difficult for producers to generate the minimum acceptable rate of return of 15% on their investments, he says.

"At lower wellhead natural gas prices, the impact of progressively more stringent water disposal options is more severe," he says. •

Water War

By Gary Clouser, Contributing Editor

Ongoing litigation between Montana and Wyoming about how to handle the release of water from coalbed methane (CBM) wells could influence production if Wyoming must find another process of releasing CBM water.

At the heart of the jurisdictional conflict is this question: Does CBM water qualify as a pollutant covered by the federal Clean Water Act? Montana's current administration says yes; Wyoming's says no.

The U.S. Environmental Protection Agency (EPA) hasn't ruled on Wyoming's attempt to prevent Montana from enforcing Montana's standards. The U.S. Department of Energy (DOE) has testified at EPA hearings against Montana's proposal. Also at debate: Who has the jurisdiction to settle this dispute?

Montana is seeking to enforce its proposed rules to control the discharge of CBM water. Its gas producers would have to re-inject the water into the ground or remove salts and other pollutants before discharging it into streams following acquisition of the proper permits. Montana's efforts are meeting fierce opposition from Wyoming, which lies upstream in the Powder River Basin (PRB). The new rules would require the Powder and Tongue rivers, which cross the state line into Montana, to meet tough water-quality standards. Wyoming officials have accused Montana of targeting their state's thriving CBM industry.

"The water disposal problems with Montana are a result of standards they (Montana officials) set at the border in 2003 that are often lower than the existing background conditions of the streams without any CBM water being discharged into the streams," explains Don Likwartz, oil and gas supervisor for Wyoming's Oil and Gas Conservation Commission. "Plus, now Montana is trying to enact even stricter standards for the three streams in the Powder River Basin that flow from Wyoming into Montana. As a result, Wyoming has joined two lawsuits filed by several operators and filed

continued on page 18

YEAR DRILLED	WELLS	GAS PROD, Bcf	Bbl/Water/Mcf	WATER PROD, MMBW
2006	2,900	350	1.70	595
2007	1,450	280	1.65	462
2008	1,500	225	1.60	360
2009	3,000	300	1.70	510
2010	3,000	400	1.85	740
2011	3,000	500	2.00	1,000
2012	3,000	500	2.25	1,125
2013	3,000	500	2.50	1,250
2014	3,000	500	2.25	1,125
2015	2,000	450	2.00	900
2016	1,000	400	1.90	760
2017	795	350	1.80	630
2018	-	300	1.70	510
2019	-	250	1.60	400
2020	-	200	1.50	300
2021	-	175	1.45	254
2022	-	150	1.40	210
2023	-	125	1.35	169
2024	-	100	1.30	130
2025	-	75	1.25	94
2026	-	50	1.20	60
2027	-	25	1.15	29
2028	-	10	1.05	11
2029	-	5	1.00	5
TOTAL	**27,645**	**6,220**	**1.87**	**11,629**

Source: Wyoming Oil and Gas Conservation Commission

The Powder River Basin drilling forecast suggests less produced water in time.

continued from page 17

suit against the EPA."

Richard Opper, director of the Montana Department of Environmental Quality, says Montana's intention is to protect irrigation and other long-standing uses of high-quality water, including that from the Powder River.

"Our concern is that meeting the water-quality standards at the border may not be good enough to protect beneficial uses downstream," he says.

He says he had hoped the neighboring states could resolve the dispute without bringing in the courts and federal agencies, but that no longer looks possible.

Produced-water quality in the PRB is much better than in other basins and has a high potential for use as a beneficial water resource. Injection of produced water represents a loss of a valuable resource to landowners in the semi-arid PRB, the alliance says.

Coalbed natural gas water in its unaltered state usually meets or exceeds the Wyoming and Montana departments of environmental quality's surface water-quality standards, says Karen Brown, alliance coordinator.

In Wyoming, since every CBM well must be permitted as a gas well and a water well, the operator must obtain permits from the Wyoming Oil and Gas Conservation Commission or the United States Bureau of Land Management, if the well is on federal land; and the State Engineer's Office. Water discharges are permitted with the Wyoming Department of Environmental Quality. The alliance says its mission is to distribute information and communication about CBM development within the PRB play in Montana and Wyoming. •

Admiral Bay Resources Inc.

Admiral Bay Resources Inc. is an emerging unconventional gas production company focused on the development of projects in the Cherokee Basin in southeast Kansas and the Appalachian Basin in Pennsylvania.

In the first 2 1/2 years of operation, Admiral Bay has accumulated leases totaling 170,000 acres, drilled or reactivated over 255 wells, installed over 48 miles of gathering system and established Proved Reserves of over 35 Bcf (3P reserves total 278 Bcf, as at July 31, 2006). Over the coming months, the Company will focus on connecting its inventory of new wells to the pipeline and rapidly expanding production.

For Further Information Contact:

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7060 South Tucson Way, Suite B,
Centennial, CO 80112

Toll Free: 866-217-1620
Tel: 604-628-5642
Email: info@admiralbay.com

www.admiralbay.com

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Company	State(s)	Basin(s)
44 Canyon LLC (Hallwood Petroleum)	Colorado	
Admiral Bay Resources Inc.	Kansas	Cherokee
Admiral Bay Resources Inc.	Pennsylvania	Appalachian
Anadarko Petroleum Corp.	Utah	Uinta
Anadarko Petroleum Corp.	Wyoming	Washakie, Hanna Powder River
Antero Resources	Colorado	
Appalachian Energy	Virginia	
AX&P Inc.	Kansas	
Barger Engineering	Illinois	Illinois
Benson-Montin-Greer Drilling Corp.	New Mexico	San Juan
Berenergy Corp.	Wyoming	
Berry Petroleum	Illinois	Illinois
Berry Petroleum	Kansas	Forest City
Berry Petroleum	Utah	Uinta
Big Basin Petroleum LLC	Wyoming	
Big Run Production Co.	Colorado	
Bill Barrett Corp.	Colorado, Wyoming	
BJ Davis Oil Co.	Kansas	
Black Diamond Energy Inc.	Wyoming	Powder River
Black Gold Gas and Oil	Kansas	Cherokee
Black Hills Exploration & Production Inc.	Colorado	
Black Hills Gas Resources	New Mexico	San Juan
Blackstone Operating Inc.	Wyoming	
Blake Production LLC	Wyoming	
Blue Jay Operating	Kansas	Cherokee
Bonanza Energy Corp.	Kansas	
Boom Co.	Kansas	Cherokee
Bowden Energy Co.	Wyoming	
Bowers Oil & Gas	Wyoming	
BP America Production Co.	Colorado	
BP America Production Co.	New Mexico	San Juan
BPI Energy	Illinois	Illinois
Breck Operating Corp.	New Mexico	San Juan
Brower Oil and Gas	Kansas	Cherokee
Buckwheat Gas & Oil LLC	Kansas	Cherokee
Burlington Resources (ConocoPhillips)	Colorado, New Mexico	San Juan
C&H Well Servicing Inc.	Wyoming	
Cain, Vance	Kansas	
Calumet-Eakin Gas Co.	Kansas	Cherokee
Canary Operating Co.	Kansas	
Canest LLC	Ohio	Central Appalachian
Carroll Energy	Kansas	Cherokee
Caulkins Oil Co.	New Mexico	San Juan
CB Gas Managers (Spartan Energy, Wolverine Energy, Federated Oil and Gas)	Kansas	
CDX Gas LLC	Arkansas	Arkoma
CDX Gas LLC	Pennsylvania, West Virginia, Wyoming	
CDX Rio LLC	New Mexico	San Juan
Cedar Ridge LLC	Colorado	
CH4 Energy LLC	Wyoming	
Chaparral Oil & Gas Co.	New Mexico	San Juan
Chatauqua O&G	Kansas	
Chevron USA	Colorado	San Juan
Chevron USA	New Mexico	San Juan
Citation Oil & Gas Corp.	Wyoming	
Clear Creek Exploration	Kansas, Utah	

Company	State(s)	Basin(s)
CNB Enterprises	Kansas	
CNX Gas	Illinois	Illinois
CNX Gas	Kentucky	
CNX Gas	Pennsylvania, West Virginia	Northern Appalachia
CNX Gas	Virginia	Central Appalachia
Coal Creek Minerals LLC	Wyoming	
Coleman Oil & Gas Inc.	Wyoming	
Coleman Oil & Gas Inc.	New Mexico	San Juan
Colt Energy Inc.	Kansas	Cherokee
Comet Energy Services LLC	Wyoming	
ConocoPhillips	Canada	
ConocoPhillips	Colorado, New Mexico	San Juan
ConocoPhillips	Utah	Uinta
Conquest Oil	Kansas	
Consolidated Gas and Energy	Kansas	
Continental Industries LC	Wyoming	
D J Simmons Inc.	New Mexico	San Juan
Dakota Production Co. Inc.	Kansas	Cherokee
Dart Cherokee Basin Operating Co.	Kansas	Cherokee
Davis Operating	Kansas	Cherokee
Delta Petroleum Corp.	Colorado	Piceance, Denver-Julesburg
Desert Mining (44 Mag Production)	Wyoming	Powder River, Washakie
Devon Energy Corp.	Oklahoma	
Devon Energy Corp.	New Mexico	San Juan
Devon Energy Corp.	Wyoming	Wind River
DNR Oil & Gas Inc.	Wyoming	
Dominion	New Mexico	San Juan
Dorado Gas Resources	Kansas	Cherokee
Double 7 Oil and Gas	Kansas	Cherokee
DTE Methane Resources	Illinois	Illinois
Dugan Production Corp.	New Mexico	San Juan
Duncan Oil Inc.	Wyoming	
El Pamco Inc.	New Mexico	San Juan
El Paso E&P Co.	Alabama	Black Warrior
El Paso E&P Co.	Colorado	Powder River
El Paso E&P Co.	New Mexico, Colorado	Raton
El Paso E&P Co.	Oklahoma	Arkoma
Elm Ridge Exploration Co. LLC	Colorado	
Elm Ridge Exploration Co. LLC	New Mexico	San Juan
Emerald Operating Co.	Wyoming	
EnCana Oil & Gas (USA) Inc.	Canada	Horseshoe Canyon (Southern Alberta)
EnCana Oil & Gas (USA) Inc.	Colorado	Piceance
Endeavor Energy Resources	Kansas	
Energen Resources Corp.	Colorado	
Energen Resources Corp.	New Mexico	San Juan
Energy Quest Resources	Kansas	Cherokee
Enernet of Wyoming	Montana	Powder River
EnerVest Management Partners	Pennsylvania	Appalachian
Equitable Production	Kentucky	
Equitable Production	Virginia, West Virginia	Appalachian
Exxon Mobil Corp.	Colorado	
Federated Oil & Gas Properties	Wyoming	
Fidelity E&P Co. (MDU Resources)	Wyoming	
Fidelity E&P Co. (MDU Resources)	Montana, Wyoming	Powder River
Finite Resources	Illinois	Illinois
Florentine Exploration and Production	Montana	Powder River

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Foree International LLC	Pennsylvania	Appalachian
Forest City LLC	Kansas	
Fort Scott Methane Producers	Kansas	Cherokee
Foster Oil and Gas	Kansas	Cherokee
Foundation Coal West Inc.	Wyoming	
Four Star Oil & Gas Co.	Colorado	
Four Star Oil & Gas Co.	New Mexico	San Juan
Galaxy Energy Inc.	Montana, Wyoming	Powder River
Galaxy Energy Inc./Charles D. Roye	Kansas	Cherokee
Gastar Exploration Ltd.	Wyoming	Powder River
Geomet Inc.	Alabama	Cahaba, Black Warrior
Geomet Inc.	British Columbia, Colorado, Louisiana	
Geomet Inc.	West Virginia, Virginia	Central Appalachian
Gosney & Sons	Colorado	
Grayson Hill Energy	Illinois	Illinois
Great Eastern Energy and Development	Kansas	Cherokee
Great Lakes Energy Partners (Range Resources)	Pennsylvania	Appalachian
Great Western Drilling Co.	New Mexico	San Juan
Greene Energy (Consol Energy)	Pennsylvania	
Gulf Energy Management (Harken Energy)	Indiana	
Gulf Energy Management (Harken Energy)	Ohio	Central Appalachian
Gunnison Energy Corp. (Oxbow Group)	Colorado	Piceance
Heartland Energy Co.	Wyoming	
Heartland Oil and Gas (Eden Energy)	Kansas	Bourbon Arch
HEC Petroleum Inc.	New Mexico	San Juan

Company	State(s)	Basin(s)
High Energy Inc.	Wyoming	
Highline Exploration Co.	Montana	Powder River
Hilcorp Energy Co.	Wyoming	Powder River
Holcomb Oil & Gas Inc.	New Mexico	San Juan
Hopewell Operating	Kansas	Cherokee
Horseshoe Operating Co.	Kansas	Cherokee
Indianola Oil Inc.	Kansas	
Infinity Oil & Gas of Wyoming	Wyoming	Greater Green River
J.M. Huber	Kansas	Cherokee
J.M. Huber	Montana	Powder River
J.M. Huber	Wyoming	
James R. Cantrell Co.	Illinois	Illinois
JEB Oil Research	Kansas	
Jesmar Energy	Pennsylvania	
JH Bullard	Kansas	
JJ Leasing	Kansas	
Jones and Buck Development	Kansas	
Jones Gas Corp.	Kansas	Cherokee
Jones, Stephen C.	Kansas	Forest City
J-W Operating Co.	Utah	Uinta
Kennedy Oil	Wyoming	Powder River, Green River
Kerr-McGee Corp. (Anadarko)	Utah	Uinta
Kimbell Oil Co. of Texas	New Mexico	San Juan
KMV Consulting (Mammoth Energy Group)	Oklahoma	
Koch Exploration Co. LLC	New Mexico	San Juan
Kukui Operating Co.	New Mexico	San Juan

Company	State(s)	Basin(s)
L&J Operating Inc.	Wyoming	
Lance Oil & Gas Co. (Anadarko)	New Mexico	San Juan
Lance Oil & Gas Co. (Anadarko)	Wyoming	
Layne Energy Operating Co.	Kansas	Cherokee
Lazy J Oil and Gas	Kansas	Cherokee
Lee Donna Oil	Kansas	
Longton Explorations	Kansas	Cherokee
Loral Operating LLC	Wyoming	
M&G Drilling Co.	New Mexico	San Juan
Majestic Petroleum Operations Inc.	Wyoming	
Manana Gas Inc.	New Mexico	San Juan
Maralex Resources Inc.	Colorado	
Maralex Resources Inc.	New Mexico	San Juan
Marathon Oil Co.	Utah	Uinta
McElvain Oil & Gas Properties	Colorado	
McElvain Oil & Gas Properties	New Mexico	San Juan
McGown Drilling	Kansas	Cherokee
Medallion Exploration	Wyoming	
Merit Energy Co.	Wyoming	
Merrimac Oil & Gas LLC	Wyoming	
Merrion Oil & Gas Corp.	New Mexico	San Juan
MS Drilling Co.	Kansas	Cherokee
MTG Operating Co.	Wyoming	
NM&O Operating Co.	New Mexico	San Juan
N&B Enterprises	Kansas	
Nami Resources	Kentucky	
National Fuel Corp.	Colorado	

Company	State(s)	Basin(s)
Neosho Natural	Kansas	Cherokee
Newfield Exploration	Oklahoma	Cherokee
Nexen	Canada	
North Finn LLC	Wyoming	
Northwest Energy LLC	Wyoming	
Oilfield Salvage & Service Co.	Wyoming	
Osage Resources	Kansas	Forest City, Cherokee
Osborn Energy LLC	Kansas	Forest City
Pablo Operating Co.	Colorado	
Patina San Juan Inc. (Noble Energy)	New Mexico	San Juan
Patrick Petroleum	Kansas	Cherokee
Patriot Production LLC	Wyoming	
Paxton Grant	Kansas	Cherokee
Peabody Natural Gas	Illinois	Illinois
Peabody Natural Gas	Kentucky, Wyoming	
Penn Virginia Oil and Gas Corp.	Kansas	Cherokee
Penn Virginia Oil and Gas Corp.	Kentucky, Virginia	
Penn Virginia Oil and Gas Corp.	West Virginia	Appalachia
Pennaco Energy Inc. (Marathon Oil)	Montana	Powder River
Penneco Energy Inc. (Marathon Oil)	Wyoming	
Pennsylvania Services Corp.	Pennsylvania	
Peoples Energy Production-Texas LP	New Mexico	San Juan
Perkins Oil Enterprises	Kansas	
Petro Mex Resources	Colorado	
Petro-Canada Resources (USA)	Wyoming	
Petro-Canada Resources (USA)	Montana	Powder River

CURRENT CBM PLAYERS

Company	State(s)	Basin(s)
Petroglyph Energy (Intermountain Industries)	Colorado	
Petrogulf Corp.	Utah	
Petrogulf Corp.	Wyoming	Powder River
Petrogulf Corp.	Colorado	San Juan, Raton
Petrol Oil and Gas	Kansas	Cherokee, Western Interior
Petrol Oil and Gas	Missouri	Western Interior
Petroleum Development Corp.	Colorado	
Petroleum Development Corp.	Montana	Powder River
Petrox Resources	Wyoming	
Pine Mountain Oil and Gas Co.	Virginia	
Pinnacle Energy Group	Montana	Powder River
Pinnacle Gas Resources Inc.	Wyoming	
Pioneer Natural Resources	Canada	Horseshoe Canyon (Southern Alberta)
Pioneer Natural Resources	Colorado	Uinta, Piceance, Sand Wash, Raton
Pioneer Natural Resources	Utah	Uinta
Pogo Producing Co.	New Mexico	San Juan
Powder River Gas LLC	Montana	Powder River
PRB Oil & Gas Inc.	Wyoming	Powder River
Primary Natural Res. (Newfield Exploration)	Wyoming	
PRO NM Energy Inc.	New Mexico	San Juan
Production Maintenance Service	Kansas	Cherokee
Pulse Energy	Illinois	Illinois
Pure Petroleum LLC	Wyoming	
Pure Resources LP (Black Stone Minerals)	New Mexico	San Juan

Company	State(s)	Basin(s)
Quantum Energy Partners (EnergyQuest)	Kansas	
Quest Cherokee LLC	Kansas, Oklahoma	Cherokee
Quicksilver Resources Canada Inc.	Canada	Western Canada Sedimentary
Range Resources Corp.	Virginia, West Virginia	
RC Resources Corp.	New Mexico	San Juan
Red Willow Production Co.	Colorado	
Redstone Resources	Wyoming	
Redwine Resources	Illinois	Illinois
Redwolf Production Inc.	New Mexico	San Juan
Richardson Operating Co.	New Mexico	San Juan
Rigdon and Bruen Oil LLC	Kansas	
RIM Operating Inc.	Wyoming	
River Gas Chanute LLC	Kansas	Cherokee
Robert L. Bayless Producer LLC	New Mexico	San Juan
Rocky Mountain Gas Inc. (Enterra Energy)	Montana	Powder River
Rocky Mountain Gas Inc. (Enterra Energy)	Wyoming	
Roddy Production Co.	New Mexico	San Juan
Roxana Pipeline Co.	Kansas	Cherokee
Running Foxes Petroleum Inc.	Kansas	Cherokee
Running Horse Production Co.	New Mexico	San Juan
Samson Resources Co.	Colorado	
Sands Oil Co. Inc.	Wyoming	
Schalk Development Co.	New Mexico	San Juan
SG Interests I Ltd.	Colorado	
SG Interests I Ltd.	New Mexico	San Juan
Shawnee Oil & Gas LLC (Layne Christiansen)	Kansas	Cherokee

Company	State(s)	Basin(s)
Southwestern Production Corp.	Wyoming	
Southwind Exploration LLC	Kansas	Cherokee
St. Mary Land and Exploration (Nance Petroleum)	Wyoming	Powder River (Hanging Woman sub-basin)
Storm Cat Energy	Alaska	Cook Inlet
Storm Cat Energy	Canada	Western Canadian Sedimentary
Storm Cat Energy	Wyoming	Powder River
STP Inc.	Kansas	Cherokee
Stratco Inc.	Montana	Powder River
Stroud Oil Properties (Range Resources)	Kansas	
Suncor Energy	Kentucky, Wyoming	
Suncor Energy	Montana	Powder River
Sunwest Petroleum Inc. (Digital Gas)	Kansas	Cherokee
Synergy Operating LLC	New Mexico	San Juan
Tandem Energy (Platinum Energy)	Kansas	Cherokee
Team Energy	Illinois	Illinois
TEC Resources	Kansas	
Termco Co., The	Wyoming	Powder River
Texakoma Operating	Colorado	
The Exploration Co.	Texas	Maverick
Thomas Operating Co. Inc.	Wyoming	
Thompson Engineering & Prod.	New Mexico	San Juan
Trend Exploration I LLC	Wyoming	
Trident Exploration	Canada	Western Canada Sedimentary
Triken Oil and Gas	Kansas	
Turner Production Co.	New Mexico	San Juan

Company	State(s)	Basin(s)
Tyler Resources Group	Kansas	
UN&I	Kansas	
United States Exploration (Noble Energy)	Kansas	
Uranus Inc.	Kansas	
Urban H. Hickert	Kansas	
Ute Oil (ACT Operating)	Ohio	Appalachian
V&R Production Inc.	New Mexico	San Juan
Verde Operating Co.	Kansas	
Vessel Coal Gas Recovery (Lahd Energy)	Pennsylvania	
Warren Resources	Wyoming	Powder River, Washakie
West Largo Corp.	New Mexico	San Juan
Western Gas Resources (Anadarko)	Wyoming	
Westport Oil & Gas Co. (Anadarko)	Utah	
Whiting Petroleum	Kansas	Forest City
Whitmar Exploration	Utah	Uinta
Williams Production Co.	Colorado	Piceance
Williams Production Co.	New Mexico	San Juan
Windsor Energy Group LLC	Wyoming	
Wolverine Gas & Oil Co.	Wyoming	
XOG Operating LLC	Wyoming	
XTO Energy Inc.	Colorado	Piceance
XTO Energy Inc.	New Mexico	San Juan, Raton
XTO Energy Inc.	Utah	Uinta
XTO Energy Inc.	Wyoming	
Yates Petroleum	Montana	Powder River
Yates Petroleum	New Mexico	San Juan
Yates Petroleum	Wyoming	Green River

Hitting the Target

Quicksilver Resources Canada targets coalbed methane with new well-placement technology.

Advanced drilling technology may soon open new development opportunities for producers of unconventional gas in Canada's Alberta province and elsewhere. Tests are under way to evaluate production from two horizontal wells placed in wide, thin sheets of coal. If the wells prove economically viable, drillers in the region will have new tools to reach this elusive prize.

Seams of coal typically contain some amount of methane—absorbed or as a free gas. The Alberta Energy and Utilities Board estimates 20.9 billion cubic meters of coalbed methane remain in areas of Alberta, where commercial production is already under way from some 6,000 relatively inexpensive and closely spaced vertical wells. These vertical wells suffice when the target is thick enough; however, they can be uneconomic on thinner plays because of wellbore coverage across the producing zone.

Although several operators have attempted to drill and complete horizontal wells through these thinner zones, results prove that most of the coalbed methane trapped there is not produced. With horizontal completions at least double the cost of vertical wells in the same region, they can be uneconomic unless they produce substantially more than the vertical wells.

"The problem is that the thin coal reservoirs of western Canada are often sandwiched between layers of unconsolidated shale," says Hal Morris, drilling and completions manager for Quicksilver Resources Canada Inc. (formerly MGV Energy), a subsidiary of Texas-based Quicksilver Resources Inc.

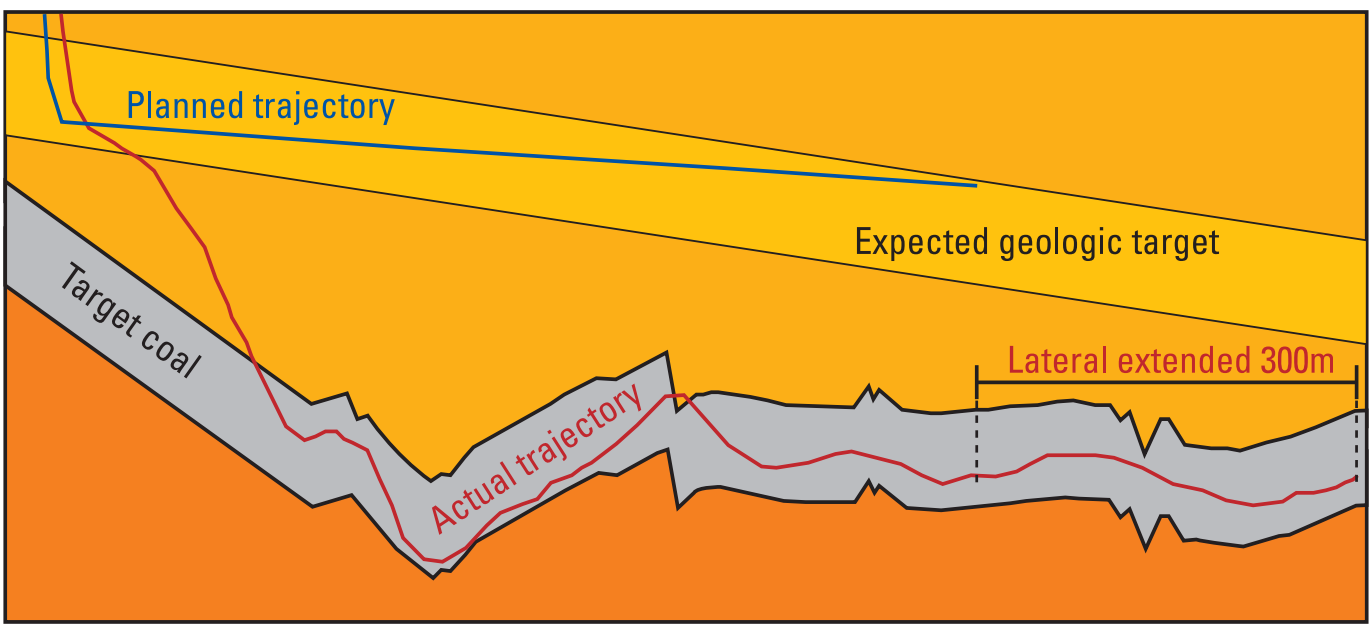
"Drilling horizontally through the thinnest zones is a challenge," Morris says. "The target may be as little as a meter thick. Conventional geosteering tools tell us when the drillbit is in the coal or in the shale, but only after the fact. If the bit enters the shale, we have to stop drilling, back up and look for the coal again. Once you start searching that way, it's a recipe for trouble."

Optimizing wellbore placement requires avoiding unstable and unproductive shale while maximizing the coverage of the wellbore in the productive zone. If the wellbore intersects too much of the unstable shale above or below the coal, the hole could collapse, resulting in a potential loss of drilling equipment or necessitating a sidetrack. Either scenario adds to the cost of the well and detracts from its productive potential. Previous attempts at horizontal wells only achieved 40% to 60% of coverage within the target coal.

In an attempt to improve on the historical drilling performance, Quicksilver recently drilled two more horizontals into thin layers of coal, employing a combination of the Schlumberger PeriScope 15 bed boundary detector, and a PowerDrive X5 rotary steerable system.

"After evaluating other systems, we felt that this combination was our best option," Morris says.

The bed-boundary detector that Quicksilver used differs from conventional geosteering technology in



The combination of PeriScope 15 and PowerDrive X5 kept the horizontal well more than 99% within the coal. The planned trajectory shown in blue would have missed the target zone. (Graphic courtesy of Schlumberger)

its ability to "see" in a radius up to 15 feet perpendicular to the drillstring. This is accomplished by sensing changes in the electrical resistivity of the rock at various spacing intervals.

Since coal has a different resistivity profile than shale, the tool can identify its relative positioning to the upper or lower boundaries of the target layer. The combination of the rotary steerable system and the new well-placement technology allowed Quicksilver engineers to drill continuously through the soft coal, making directional changes based on measurements in real time, without impacting the drilling process.

"That allowed us to drill the horizontal sections of both wells much faster than we expected, with the wellbores intersecting a high percentage of the coal," says Joe Farley, vice president of Quicksilver Resources Canada. "The first completion is more than 99% within the coal. Our second well is in a more geologically complex formation, but even so, we kept the wellbore within the target more than 70% of the time."

The combination of the rotary steerable system and the new well-placement technology allowed Quicksilver engineers to drill continuously through the soft coal, making directional changes based on measurements in real time, without impacting the drilling process.

During the drilling phase of the wells, a joint team of Quicksilver and Schlumberger experts were at the location while operations were monitored and coordinated from the Schlumberger Operations Support Center in Calgary, which was equipped with a direct satellite link to the rig location. Both wells resulted in horizontal sections of roughly 1,000 meters that follow the natural contour of the coal reservoir.

Although Quicksilver is still evaluating the performance of the two horizontal CBM wells, the commercial production of natural gas from Alberta's thin coal layers is now one step closer to being a reality.

"We are encouraged," Farley says. "One of our goals was to access as much coal as we could with these wells. Now we know the tools are available to do that." •

—Oil and Gas Investor

GEO-MODELING OF THIN-BED COAL RESERVOIRS

Measuring the thickness and quality of thin coalseams can be a challenge.

Steve Phillips, vice president and geologist at Ryder Scott Petroleum Consultants, the consulting engineering firm, says that even though volumetric analysis of original and remaining gas content is a routine step in estimating coalbed methane reserves, measuring the thickness and quality of thin coal seams is frequently a problem because of the limitations of the wireline-log resolution.

Phillips made his remarks at the Ryder Scott reserves conference this spring. He said the firm confronted this issue during a recent assignment to create a 3-D geologic model of a Black Warrior Basin coalbed-methane field.

The bulk density log is the key to identifying coal thickness and quality, Phillips said. Logs run in the study-area wells are recorded on a 1/10th-foot sample interval and have a vertical resolution of about 18 inches.

In other words, the detector on the logging tool must be about 1.5 feet or more above or below the boundary between coal and adjacent rock before it can yield a reliable density reading of the seam, he said.

Therefore, the minimum density observed in seams thinner than about 3 feet will be some value between the true density of the coal and that of the surrounding rock. This problem is also known as "shouldering," (Figure 1).

A 3-D geologic model attempts to simulate a reservoir by approximating the actual geologic conditions with a finite number of box-like cells, which represent the physical bulk volume of the reservoir.

"Think of a room filled with pizza boxes. These boxes occupy space and can be filled with a variety of values that represent reservoir properties. Think of pizza and toppings in each box," Phillips said.

He designed the geologic model to compensate for the shouldering effect to give thin coal seams their most realistic gas content. Phillips set the cell height to 6 inches, providing each cell with five density samples from the wireline log for upscaling into a single value. He used density logs previously normalized by Ryder Scott contract petrophysicist Rick Richardson.

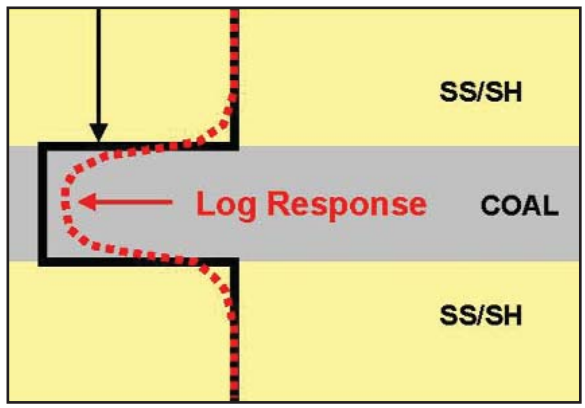


Figure 1. Actual density profile.

Commonly, upscaling involves a simple averaging of the finely sampled input values into cells penetrated by a well. However, in this case, Phillips chose the minimum density value as the single density number representing each cell.

"By choosing the minimum value, cells at the upper and lower coal-seam boundaries are not severely penalized for shouldering effects," he said. "And for thicker coal seams, where the log reading is reliable, the result is the same as averaging the individual log readings," (Figure 2). •

Reprinted with permission from Ryder Scott Petroleum Consultants, Houston. For more information on geological modeling, contact steve_phillips@ryderscott.com. *A full recap of the reserves conference was published in the June 2006* Reservoir Solution, *a newsletter from Ryder Scott.*

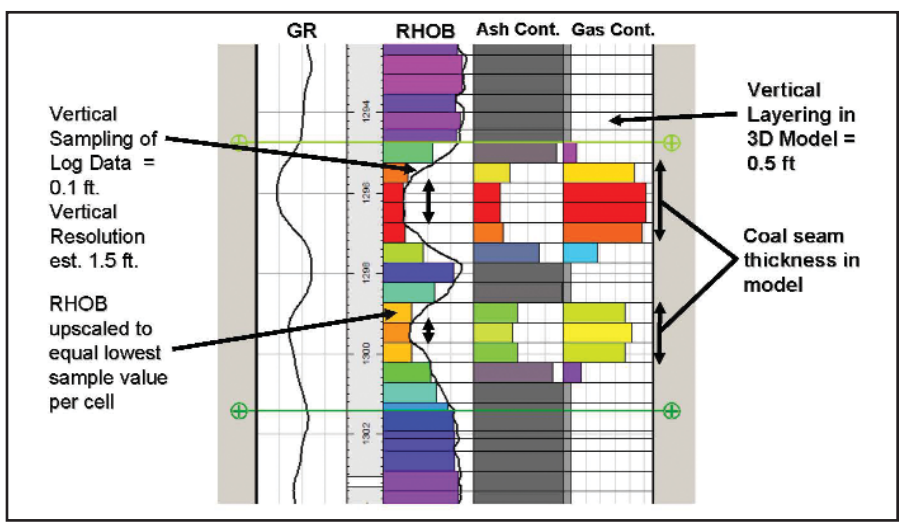


Figure 2. Log-reading sample.

20/20 vision sharpens our focus

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Maintaining continual growth requires diligence, planning and the right blend of risk and reserve. Fidelity's natural gas and oil reserves have grown to 616 Bcfe in the last five years. Natural gas production has grown 12 percent and oil production has grown 10 percent in the past seven years. The team at Fidelity has the proven knowledge, skill and resources to meet and exceed the market's expectations. Mom might call that a "24-carrot" company.

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