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TECHNOLOGY DEVELOPMENTS IN NATURAL GAS EXPLORATION, PRODUCTION AND PROCESSING

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Basin Center Gas 4 **Reducing the Risk of Exploring For Anomalously Pressured Gas Assets**
Innovative Discovery Technology's newly developed diagnostic tools are helping Wind River Basin operators find and produce the basin's large anomalously pressured gas resources.

Produced Water 9 **Coalbed Natural Gas Resources: Beneficial Use Alternatives**
The final article in this series discusses treatment technologies and alternative uses for coalbed natural gas produced water.

Unconventional Resources 15 **Tight Gas Sands Development–How to Dramatically Improve Recovery Efficiency**
Integrated application of joint DOE/NETL and industry-sponsored intensive resource development technology could double the volume of natural gas considered technically recoverable from tight gas sands in Rocky Mountain basins. This is the first of a three-part series.

Canadian Resources 21 **Gas Potential of Selected Shale Formations in the Western Canadian Sedimentary Basin**
A preliminary study by Gas Technology Institute evaluated the geochemical, geological and structural characteristics of the shale packages in the Western Canadian Sedimentary Basin.

Gas Processing 26 **Large-Scale Sulfur Recovery**
Recovery methods become more critical as gas production encounters more sulfur.

Laser Technology 29 **New High-Power Fiber Laser Enables Cutting-Edge Research**
The recent commercial availability of high-power fiber lasers presented a timely opportunity for Gas Technology Institute to enhance ongoing research of laser applications for well construction and completion.

Liquified Natural Gas 32 **Continuing Development of LNG Safety Models**
Gas Technology Institute and the University of Arkansas are soliciting interest from organizations to participate in research to further expand the capabilities of modeling tools used to assess potential hazards associated with liquefied natural gas terminal and shipping operations.

Items of Interest

3 Editors' Comments

34 Briefs and New Publications

35 Events Calendar and Contacts

GTI-03/0207

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CONTENTS

Editors' Comments 3
Basin Center Gas 4
Produced Water 9
Unconventional Resources 15
Canadian Resources 21
Gas Processing 26
Laser Technology 29
Liquified Natural Gas 32
Briefs and New Publications 34
Events and Contact Information 35

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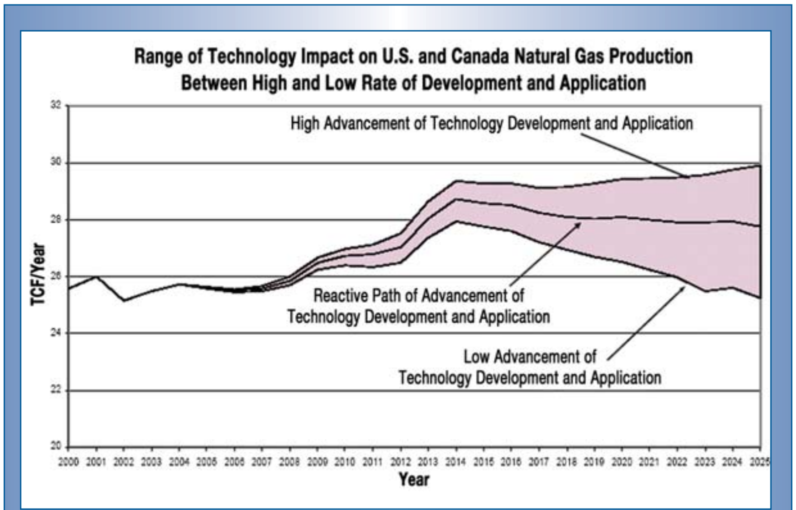
A Balanced Future for Natural Gas Research

The National Petroleum Council's report on natural gas describes a difficult but necessary path for future gas development.

In March 2002, Spencer Abraham, Secretary of the U.S. Department of Energy (DOE), requested that the National Petroleum Council (NPC) undertake a study on natural gas in the United States. The study was to examine the implications of increasing demand, new sources of supply, new technologies, and evolving market conditions for natural gas prices and delivery reliability through 2025. Abraham was particularly interested in actions that industry and government could take to ensure adequate and reliable supplies of energy for U.S. consumers.



The NPC on Sept. 25, 2003 unveiled a summary of its findings and recommendations. It was a result of more than a year of work by three task groups – Demand, Supply, and Transmission & Distribution – with representatives from large and small gas producers, transporters, service providers, financiers, regulators, local distribution companies, power generators and industrial consumers of natural gas.

These findings, essentially the informed, collective view of the U.S. gas industry, state that policies that continue to encourage the use of natural gas but discourage access to additional supplies will result in undesirable impacts to consumers and the economy.

In the study, the NPC developed two scenarios of future supply and demand that move beyond the status quo: a "Reactive Path" and a "Balanced Future." Both require significant actions by policy makers and industry stakeholders, but the Balanced Future scenario builds in additional supportive policies for supply development and allows greater flexibility in fuel choice by power producers.

The report recommends more than 50 specific actions that government can take to improve the likelihood that the lower-gas-price environment of the Balanced Future scenario is the path the country travels during the next 20 years. These recommendations include:

- removal of barriers to energy efficiency improvements in power plants (New Source Review reforms);
- providing certainty regarding Clean Air Act provisions;
- enabling legislation for an Alaskan gas pipeline;
- encouraging the construction of liquefied natural gas terminals;
- streamlining permitting for drilling in the Rocky Mountains;
- removal of Outer Continental Shelf leasing moratoria; and
- a more efficient review process for proposed pipeline projects.

An important assumption in the NPC's Balanced Future scenario is that the DOE continues initiatives that complement privately funded research efforts.

On the supply side, the NPC supports a significant DOE role in upstream research, particularly where it complements privately funded research efforts. The NPC also recommends a re-evaluation of the technology research funding levels for natural gas relative to other fuels "in light of the increasing challenges facing natural gas."

The importance of the relationship between new technology research and development (R&D) and future gas supply is more fully discussed in the Supply Chapter of Volume II of the NPC report. According to the chapter, by the year 2025, a difference in the rate of development and application of new exploration and production (E&P) technologies could mean the difference between 25 Tcf/year and 30 Tcf/year for the combined U.S. and Canada natural gas production capability.

The NPC study is encouraging because it outlines a path for increased domestic use of clean-burning natural gas within the context of a thriving economy and the security of a range of domestic and non-domestic supply alternatives. However, it is also sobering in its recognition of the effort needed to keep us on that path. The National Energy Technology Laboratory, along with other research partners such as the Gas Technology Institute, is proud to be a part of that "balanced" effort.

For more information, visit *www.npc.org*. ✧

The Editors

Reducing the Risk of Exploring for Anomalously Pressured Gas Assets

By Ronald C. Surdam,
Zunsheng Jiao
and Yuri Ganshin,
Innovative Discovery Technologies LLC

Innovative Discovery Technology's newly developed diagnostic tools are helping Wind River Basin operators find and produce the basin's large anomalously pressured gas resources.

Anomalously pressured gas accumulations in the Rocky Mountain Laramide Basins (RMLB) are a large gas resource, but one that has been difficult to exploit. The goal of this work is to maximize exploration risk reduction when exploring for such gas accumulations in the RMLB – or anywhere in the world – by gaining a better understanding of the rock/fluid characteristics of the RMLB generally and the Wind River Basin specifically. Critical to this effort, funded by the U.S. Department of Energy/National Energy Technology Center, are the evaluation of gas distribution in the fluid system, and prediction of enhanced porosity and permeability in the rock system.

Detailed sonic and seismic interval velocity analyses were used to evaluate the spatial distribution of water- and gas-rich fluid-flow domains. The basinwide fluid-flow regime in the Wind River Basin was determined in the following steps:

- a detailed velocity model was established from sonic logs, 2-D seismic lines and, if available, 3-D seismic data. Automatic picking technology using continuous, statistically derived seismic interval velocity selection and conventional graphical interactive methodologies were used to construct the seismic interval velocity field;
- velocities calculated from the constructed ideal regional velocity/depth function – the velocity/depth trend resulting from the progressive burial of a rock/fluid system of constant rock/fluid composition, with all other factors remaining constant – were removed from the observed sonic or seismic interval velocity/depth profile; and
- removal of these velocities allowed: (1) evaluation of the regional velocity inversion surface (for example, the pressure surface boundary separating normally pressured rocks above from anomalously pressured rocks below, either under- or over-pressured); (2) detection and delineation of gas-charged, multiphase fluids domains beneath the velocity inversion surface (for example, volumes characterized by anomalously slow velocities); (3) evaluation of variations within the internal fabric of the velocity anomaly, which thereby isolated intense, anomalously slow velocity domains; and (4) determination of the distribution of single-phase, water-rich fluid-flow regimes under meteoric water drive.

Anomalous velocity model for the Wind River Basin

Using this procedure, an anomalous velocity (AV) volume can be constructed for a particular area or, in the case of the Wind River Basin, for the whole basin. The AV volume constructed for the Wind River Basin was based on about 2,000 miles of 2-D seismic data and 175 sonic logs, for a total of 132,000 velocity/depth profiles. The technology was tested by constructing 10 cross-sections through the AV volume coincident with known gas fields. In each cross-section, a strong, intense, anomalously slow velocity domain coincided with the gas productive rock/fluid interval.

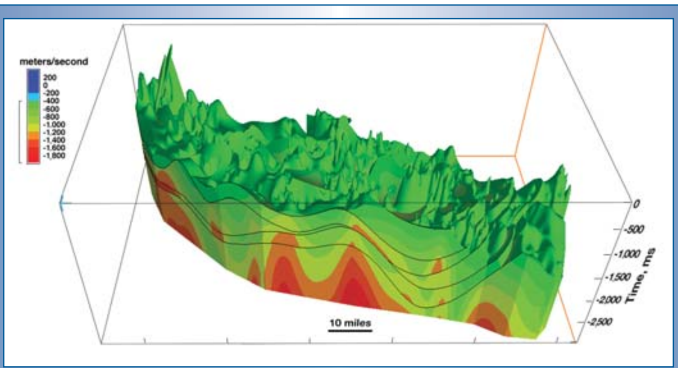


Figure 1. *Anomalous velocity model of the Wind River Basin, Wyoming, showing the relief on the regional velocity inversion surface and the gas-charged rock/fluid domain below this surface.*

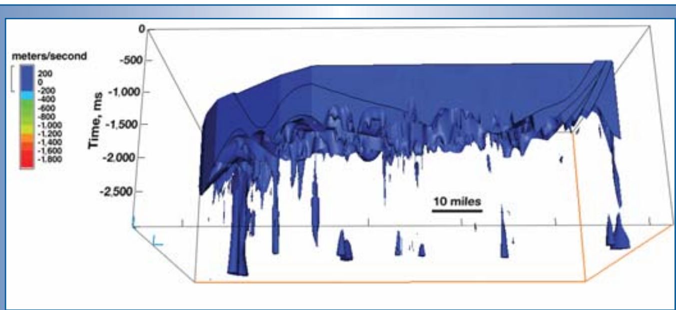


Figure 2. *Velocity model of the Wind River Basin, Wyoming, showing the base of the water-charged rock/fluid volume. In the Lower Fort Union, Lance, Meeteetse and Mesaverde units, relatively small, discontinuous, water-rich domains occur away from the basin margins. These laterally discontinuous domains are not connected to the updip meteoric water fluid-flow system.*

The AV volume for the Wind River Basin can be used to:

- delineate the regional velocity inversion surface (Figure 1; the regional pressure surface boundary), or the depth at which the observed velocity value begins to become significantly slower than predicted at that depth by the ideal regional velocity/depth function;
- easily isolate gas-charged rock/fluid systems characterized by anomalously slow velocities (Figure 1) and water-rich rock/fluid systems characterized by normal velocities (Figure 2), which fall along the regional ideal velocity/depth trend.

ROCKY MOUNTAIN BASINS	INTERNATIONAL
Powder River Basin, WY	Mahakam Delta (East Kalimantan), Indonesia
Bighorn Basin, WY	Kiru Trough (Sumatra), Indonesia
Wind River Basin, WY	Waropen Basin, Indonesia
Badger Basin, WY	Offshore Camaroons (West Africa), Cameroons
Washakie Basin, WY	Bohai Bay, China
Green River Basin, WY	South China Sea, China
Hanna Basin, WY	Yellow River Delta, East China
Hoback Basin, WY	Cooper Basin, Australia
Great Divide Basin, WY	San Jorge Basin, Argentina
Sand Wash Basin, WY, CO	Neuquen Basin, Argentina
Denver Basin, CO	Maturin Basin, Venezuela
Piceance Basin, CO	Cauca Valley, Colombia
South Park Basin, CO	
Uinta Basin, UT	
San Juan Basin, NM	
West Canada (Alberta) Basin, Canada	
Other North American Basins	
Western Anadarko Basin, OK	
Sacramento Basin, CA	

Table 1. *List of basins in which the Innovative Discovery Technology exploration strategy and associated technologies have been successfully applied.*

Regional velocity inversion surface

The regional velocity inversion surface is an important boundary with respect to the fluid-flow and rock/fluid regimes. This pressure surface boundary separates normally pressured, water-rich (typically single-phase) fluid-flow systems above from anomalously pressured (under- or over-pressured), multiphase, gas-charged fluid-flow systems below. The surface is characterized by:

- a steepening of the vitrinite reflectance (R_O)/depth gradient at the boundary, which suggests a significant difference in the thermal regime above and below the regional velocity inversion surface;
- a significant change in formation water chemistry within individual stratigraphic units, which suggests an individual marine unit above the boundary is more likely to be flushed with meteoric water than the same unit occurring below the boundary;
- acceleration of the reaction rate of smectite-to-illite diagenesis in mixed-layer clays; and
- an increase in bitumen and remnant liquid hydrocarbons below the surface.

Capillary properties are one of the most important rock/fluid attributes that change in relation to the regional velocity inversion surface. An increase in capillary displacement pressures occurs across the regional velocity inversion surface from a few hundred pounds per square inch (psi) above to a few thousand pounds per square inch below the surface. This change is important because of its effect on sealing capacity. Above the regional velocity inversion surface, certain fine-grained lithologies in individual stratigraphic units are capable of supporting gas columns a few hundred feet high, whereas beneath this surface, the same lithologies are capable of supporting gas columns several thousand feet in height. Rock/fluid systems below the surface are dominated by capillarity, which makes it difficult for fluid to move across low-permeability boundaries and increases the potential for compartmentalization of the fluid-flow systems. In summary, all the changes in rock/fluid characteristics associated with the regional velocity inversion surface are compatible with a significant reduction in the convection of fluids across this surface or boundary.

Regional velocity inversion surfaces have been detected in more than 30 basins (Table 1) around the world using the techniques discussed above. The most detailed evaluations of lithologies associated with the regional velocity inversion surface have occurred in the RMLB. In each of these basins, the regional velocity inversion surface is commonly associated with a low-permeability lithology, which has often been modified to even lower permeability values through diagenesis. In some cases, the inversion surface cuts across stratigraphic boundaries, typically along a near-vertical fault. Where this occurs, the inversion surface follows the low-permeability stratigraphic unit laterally until it intersects a fault and jumps up or down to another low-permeability stratigraphic/lithologic unit and again continues laterally. Note that the distribution of regional velocity inversion surfaces in the RMLB is typically associated with low-permeability lithologic units such as shales, paleosols, and diagenetically and pedogenetically modified siltstones and sandstones, among others.

Topographic relief on a regional velocity inversion surface can occur along faults, fracture swarms, stacked sandstones or other stratigraphic/structural elements that result in permeability chimneys. In the Wind River Basin, many of the topographic highs on the regional velocity inversion surface are 3,000ft higher than the surrounding areas. Each of the highs represents the vertical migration of gas – gas chimney – for example; thus, these areas represent conduits characterized by enough permeability to allow vertical migration of gas.

Gas-charged domains

Other features of the fluid-flow system that can be detected and the distribution delineated are those domains beneath the regional velocity inversion surface that are intensely slow, which are interpreted to be those domains where the probability of high gas saturation is highest. These domains are characterized by AV values greater than −1,000 m/sec. The minus sign on the AV value indicates the velocity is anomalously slow. Such an AV value indicates that, at that point, the velocity falls 1,000 m/sec below or slower than predicted for that depth by the ideal regional velocity/depth function. Anomalous velocity values can vary between regions because of variations in seismic acquisition parameters and overall seismic data quality. In the RMLB, intensely slow velocity (gas-charged) domains tend to be highly compartmentalized.

Basinwide rock/fluid systems: Wind River Basin

Some locations in the Wind River Basin have columns of rock/fluid systems more than 5,000ft

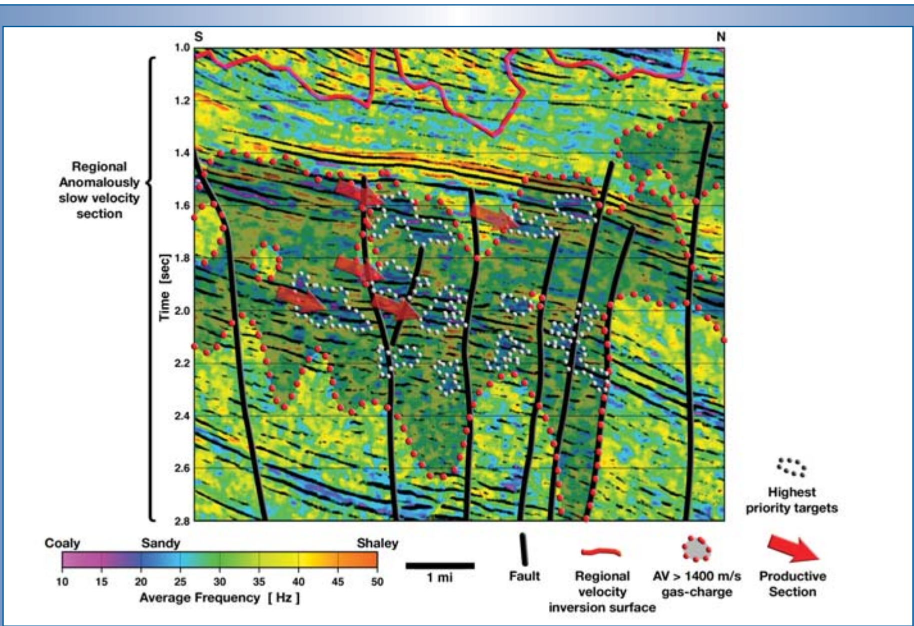


Figure 3. *Seismic data display superimposed on a frequency attribute section at Frenchie Draw field. Shaded region shows anomalous velocity overlap.*

thick characterized by continuous, anomalously slow velocities. If anomalously slow velocities equate to gas-charge in the RMLB, these areas in the Wind River Basin contain thick rock/fluid columns that have no connection to meteoric water. In other words, the velocity analysis strongly suggests the occurrence of regionally significant fluid-flow compartments, with a gas-charge in the fluid phase (a water-gas-oil system), that are isolated from meteoric water recharge. This configuration does not eliminate the possibility that trapped water is present, perhaps even substantial, smaller water-dominated domains within the large regional gas-charged compartments. However, if such water-rich fluid domains exist, they are not being recharged from the meteoric water system. Most importantly, even in intensely slow velocity (gas-charged) domains, fluid-flow systems are water-gas-oil, such as in the lower Fort Union, Lance, Meeteetse and Mesaverde units, where relatively small, discontinuous, water-rich domains occur away from the basin margins.

Anomalously slow velocities do not exclude the presence of water. The most significant decrease in velocity occurs when the gas phase reaches about 20%. Knight et al. (1998) have shown there is a relationship between gas saturation distribution and velocity. The group conclude that "in a water-gas saturated reservoir, a patchy distribution of the different lithologic units is found to cause P-wave velocity to exhibit a noticeable and almost continuous velocity variation [decrease] across the entire saturation range." These findings are important, the group notes, because they indicate that in many of the reservoir intervals of interest in the RMLB, where the distribution of lithologies is patchy, a relationship between increasing gas saturation and decreasing velocity is different from the response of a homogeneous reservoir, where a single large drop in velocity occurs in the 15% to 20% saturation range. The work of Knight et al. explains why, in some relatively thick and heterogeneous reservoir intervals like the Lance Formation, there is nearly a continuous decrease in velocity as the gas-charge, as reflected by the estimated ultimate recovery of wells, increases.

This relationship between velocity and gas saturation is the main diagnostic tool used herein to evaluate the distribution of gas in the RMLB. Thus, in the anomalously slow velocity domains, a significant gas phase exists (as a gas-charged and multiphase fluid flow system), and any water present is isolated from the meteoric water flow system. Note that gas production from reservoir intervals characterized by intensely slow velocity domains in the RMLB commonly have very low initial water production.

The Wind River Basin on a regional scale is divided into at least two regionally prominent fluid-flow compartments separated by a velocity inversion surface. The upper compartment is water-dominated, probably under strong meteoric water drive, whereas the lower compartment is gas-charged, isolated and anomalously pressured. The lower boundary of the regionally gas-charged compartment was not observed in the present work, but generally it must be at a depth equivalent to 3-sec two-way travel time or greater (more than 15,000-ft depth). Based on earlier work in the Powder River Basin, there is a strong possibility the lower boundary of the regional gas-charged compartment in the Wind River Basin will be associated with the lowermost organic-rich shale in the Mesozoic section.

Judging from cross-sections through the AV volume, numerous fluid-flow sub-compartments occur within the regionally prominent gas-charged compartment beneath the regional velocity inversion surface. The geometries and boundaries of these sub-compartments are controlled by faults, other structural elements, low-permeability rocks resulting from the stratigraphic framework, such as sandstone distribution and petrophysical character, depositional setting and diagenetic history.

Distribution of potential gas-charged reservoirs

Determining the distribution of gas-charged and water-charged domains significantly reduces exploration uncertainty (risk) in Laramide basins. Even more risk reduction can be achieved by determining where targeted reservoir intervals with enhanced porosity and permeability intersect and penetrate anomalously slow velocity domains. Well log data and seismic attributes can be used to evaluate the distribution of sandstone-rich intervals within targeted reservoir units (stratigraphic units with commercial gas production potential) within the Wind River Basin.

The **Frenchie Draw** gas field in the Wind River Basin provides a good illustration of the difficulties associated with detecting and delineating gas assets beneath the regional velocity inversion surface. The field was originally drilled because of a stratigraphic trap, consisting of lenticular fluvial sandstone in the lower Fort Union/Lance stratigraphic interval, on a north-plunging structural nose. But the trapping mechanism and gas distribution pattern have proven to be complex, and the exploitation of this gas asset by conventional technologies has been fraught with significant risk, as is commonly the case in gas fields in the basin. Surdam (2004) has demonstrated a good correlation between seismic frequency and gamma ray logs, such as lithology, through the lower Fort Union/Lance strati-graphic interval at Frenchie Draw. It is concluded that seismic frequency can be used to distinguish sandstone-rich from shale-rich stratigraphic intervals in the Frenchie Draw field in the Wind River Basin.

Figure 3 shows sandstone-rich intervals with low seismic frequency (blue areas outlined by white dots and denoted by arrows) within the lower Fort Union/Lance stratigraphic section that intersect anomalously slow velocity domains (shaded area outlined by red dots) within the Frenchie Draw. The graphic shows that not only does a north-plunging structural nose occur in this area, but at the boundary between the Upper and Lower Fort Union stratigraphic units (near the upper limit of gas production) a shale-rich sequence (orange) serves as a regional seal. Also, the distribution of sandstone-rich intervals (blue) stands out against the shale-rich intervals (orange, yellow and green). The lenticular aspect of the fluvial sandstone-rich intervals is apparent. In conclusion, the distributional pattern of lithologies shown in Figure 3 corresponds with initial interpretations of geologists and geophysicists who discovered the field.

This example further illustrates the complex nature of compartmentalization of production potential within anomalously slow, gas-charged domains. The distributions of production sweet spots in this example are controlled by a variety of factors, including, but not limited to, stratigraphic and structural frameworks, all below a regional velocity inversion surface (see red line; Figure 3) and within the regionally anomalously slow velocity volume.

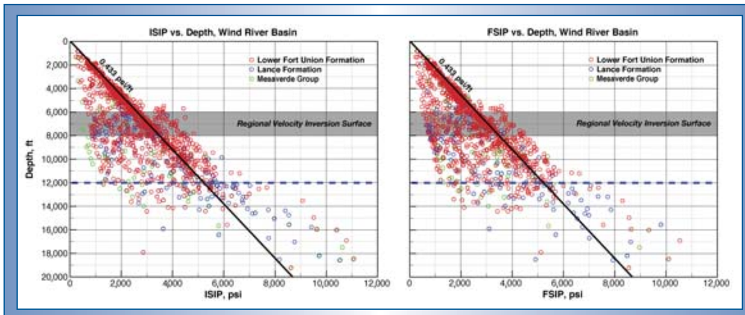


Figure 4. *ISIP (left) and FSIP (right) vs. depth for the Lower Fort Union, Lance and Mesaverde stratigraphic units from the Wind River Basin. For each unit from near surface to 12,000ft, most of the observed pressure measurements are near the hydrostatic gradient (i.e., normally pressured) or significantly under-pressured.*

Figure 4 is the pressure data for the Fort Union, Lance and Mesaverde stratigraphic units from the Wind River Basin. The Fort Union Formation pressure data were originally from 297 wells and 1,212 tests; the Lance Formation data were from 129 wells and 611 tests; and the Mesaverde Group data were from 132 wells and 323 tests. The data shown were edited according to the following scheme:

- the initial shut-in pressure (ISIP) and final shut-in pressure (FSIP) had to be reported or the test was discarded;
- the ISIP and FSIP values had to agree within 10% or the test was discarded; and
- all pressure data characterized by gradients less than 0.1 psi/ft (for example, gas gradient) were eliminated.

The observed pressure regimes in the lower Fort Union, Lance and Mesaverde units are nearly identical. Most of the observed pressure measurements are near the hydrostatic gradient (about normal) or are significantly under-pressured for each unit from near surface to 12,000-ft depth. Only when these units approach 12,000-ft present-day depth are over-pressured values (significantly >0.43 psi/ft) observed (Figure 4). From the regional velocity inversion surface (usually encountered at 6,000-ft to 8,000-ft depth) down to 12,000-ft depth, the observed pressure gradients typically are less or slightly greater than the regional "hydrostatic" pressure gradient (i.e., about 0.43 psi/ft). Much of the drilling activity for these units is for targets in the 8,000-ft to 12,000-ft depth window.

The pressure data provide substantial evidence that significant portions of the lower Fort Union, Lance and Mesaverde units are under-pressured or normally pressured. When Figure 4 is combined with Figure 1, it can be concluded that few of these rocks are in fluid-flow communication with the meteoric water system. The rock/fluid systems in the lower Fort Union, Lance or Mesaverde units below the regional velocity inversion surface are typically not under strong water drive. If exceptions to this statement exist, they will be on a local and small scale and will not be detectable on the scale of seismic data. Instead, the normal and under-pressured rock/fluid systems below the regional velocity inversion surface and above 12,000-ft depth are compart-mentalized and gas-charged, with multiphase fluid systems dominated by capillarity. Below about 12,000ft, the rock/fluid systems for all these units will likely be compartmentalized and over-pressured.

Commonly, the best gas production in Laramide basins is beneath but within 2,000ft of the regional velocity inversion surface. Typically, reservoir rocks in this area of the pressure transition (i.e., regional velocity inversion surface) have undergone less burial and diagenesis than reservoir rocks occurring deeper in the anomalously pressured rock/fluid column; they have relatively good porosity and permeability. If the rock/fluid system within this depth interval is under- or even near normal pressure, it can be easily bypassed or badly damaged.

Recent work has shown that in all the RMLB, the transition at the regional velocity inversion surface is commonly from a normally pressured to an under-pressured fluid-flow system. The potential for drilling damage to under-pressured reservoir rock in the RMLB, and probably elsewhere in the world, is universal, particularly if the under-pressured zone or interval is relatively thin and adjacent to over-pressured rock/fluid systems. The potential for yet unrecognized under-pressured gas resources in many of the RMLB is significant (excluding the Alberta and San Juan basins, where large under-pressured gas resources have been recognized and exploited). Ironically, under-pressured gas resources contain some of the best-quality reservoirs within the anomalously pressured portion of the Wind River Basin.

Conclusions

The rock/fluid characteristics of the RMLB described in this work demonstrate the potential for significant, relatively unconventional, so-called "basin-center" hydrocarbon accumulations. The rock/fluid systems characterizing the RMLB dictate that if such accumulations occur, they will be characterized by several critical attributes – as previously noted.

Because some of these critical attributes are not associated with conventional hydrocarbon accumulations, a new set of diagnostic tools is required for efficient and effective exploration and exploitation of these types of gas prospects.

To maximize exploration risk reduction when exploring for these types of gas accumulations in the RMLB, or for anomalously pressured gas accumulations anywhere in the world, it is recommended that highest priority be given to evaluating gas distribution in the fluid system, and predicting enhanced porosity and permeability in the rock system. ✧

For more information about Innovative Discovery Technology's (IDT) exploration tools and technologies, contact Ronald Surdam, president. IDT, 1275 N. 15th St., Ste. 121, Laramie, WY 82072; Tel: (307) 745-4464; e-mail: rcsurdam@idt.bz.

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Coalbed Natural Gas Resources: Beneficial Use Alternatives

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The final article in this series discusses treatment technologies and alternative uses for coalbed natural gas produced water. Information in this article is based on a research guide funded by the U.S. Department of Energy/National Energy Technology Laboratory, the Bureau of Land Management and the Grand Water Protection Research Foundation.

Coalbed natural gas production, commonly called coalbed methane or CBM, is of vital interest in the search for new natural gas resources in the United States. Coalbed methane resources in the Rocky Mountain states have generated an industry drilling boom during the past decade. The output reached 4 billion cf/d in 2002 with production from 20,000 wells. This represents 8% of all natural gas produced in the United States. Interest in CBM development is high, particularly in Wyoming, Montana and New Mexico. However, development brings with it a growing concern about how to handle the produced water. Argonne National Laboratory estimates for 2002 indicate more than 14 billion bbl/year of produced water must be handled in the United States, with an increasing amount coming from coalbed natural gas development.

Economics of CBM production depend on reducing the cost of handling produced water. Beneficial uses for produced water offer the best alternative to high-cost re-injection procedures. Various treatment or pretreatment applications (see *Coalbed Natural Gas Produced Water: Water Rights and Treatment Technologies,* ***GasTIPS***, Fall 2003, Vol. 9, No. 4, p. 13-18) may be necessary before produced water can be funneled for alternative uses. However, much of the water from CBM development in the Rocky Mountain region is of high quality and requires no or only moderate treatment prior to agricultural or industrial use.

Figure 1: *The quality of coalbed methane produced water in much of the Rocky Mountain region meets standards for wildlife and livestock watering.*

Alternatives to re-injection of CBM produced water fall in five main categories: water impoundments for stock and wildlife, irrigation, surface discharge, and recreational and industrial uses. These categories have some overlap because of drainage characteristics and storage requirements.

Water impoundments

Wildlife and Livestock Water Impoundments—Wildlife watering ponds are perhaps one of the simplest alternative uses for CBM and benefits the general public most. Wildlife watering ponds provide adequate drinking water during drought periods, create or expand suitable habitat for wildlife and may improve water quality. Because the arid western states have broad areas with inadequate surface water and prolonged periods of drought, creation of ponds using CBM produced water can be highly beneficial to resident species of deer, pronghorn, coyotes, bobcats, upland game and shore bird species. Ponds also can be constructed to provide breeding areas for waterfowl or wintering areas for migratory waterfowl and other transient bird species. The ponds also can provide habitat for fish. Ponds can be used to increase the range of certain wildlife species into areas that previously did not have sufficient surface water.

The Natural Resource Conservation Service (NRCS) has nationwide standards and design guidelines for wildlife watering facilities. Simple water tanks for remote areas where produced water of acceptable quality is available can be constructed from PVC pipe and a small tank or impoundment pit. Ponds for year-round water impoundment for wildlife, migratory birds and fish must be at least 40 acres in size with 25% of the area more than 9ft deep. Other requirements, such as fencing to protect livestock, water valves and maintenance, are provided by the NRCS. Construction and maintenance of CBM produced water wildlife watering impoundments are low-cost, and benefit private land owners as well as federal and state lands and services.

Figure 2: *Wetlands may have an additional benefit in sequestering carbon dioxide, and in a minor way help moderate global climatic changes.*

Livestock watering practices often rely on access to natural streams and lakes. In many areas, this has caused erosion and destabilization of stream banks, increased sediment load and contamination caused by increased nutrients and resulting algae bloom. Using off-channel watering facilities and CBM produced water ponds could provide additional water sources, allow the expansion of livestock grazing to areas otherwise not suitable because of limited surface water and reduce negative impacts of livestock on natural streams. Figure 1 shows a simple stock watering setup using a large equipment tire.

***Fisheries*—**Construction of fisheries is another beneficial use for CBM produced water related to wildlife impoundments and recreational uses. Off-channel ponds of sufficient size to be maintained as fish breeding habitat range in size from small private ponds to large reservoirs and lakes. When conditions of size, depth and accessibility are met, state agencies will stock the ponds with the appropriate species of fish for the region. State, federal and commercial fisheries are established to provide fish for restocking as well as commercial resale and consumption. The state and federal fisheries are an important aspect of recreational programs. Location of fishponds is dependent on available quantities of useable water. The Bureau of Land Management manages more than 85,000 miles of fishery habitat on public lands in the United States. Coalbed methane produced water has the potential to expand the number of fisheries and areas where they can be established.

Requirements for fishponds differ from state to state but primarily specify pond size, depth, year-round water capacity, erosion prevention, livestock fencing and control of flow. Consideration of CBM produced water for fishponds and hatcheries depends on dissolved oxygen and nutrient content. Coalbed methane produced water is typically low in dissolved oxygen, but the content may be increased through surface water transport, agitation or aeration. High salt or metal content could be harmful to fish populations and if present must be removed prior to use in ponds. Untreated CBM produced water in Wyoming has been used to establish ponds for rainbow trout, blue gill and small-mouth bass. Some previous stocking operations in Wyoming were halted because there was a lack of available water, but CBM produced water is used to supplement natural water in these ponds.

***Recharge Ponds*—**Recharge ponds are reservoirs constructed as off- or on-channel holding ponds, frequently called storm water ponds, retention ponds or wet extended detention ponds. Recharge ponds function as a permanent water management effort for seasonal surface water discharge. They may serve to restore depleted groundwater by water infiltration into the subsurface or primarily to improve water quality or minimize peak flow periods and flooding. Recharge ponds lower the total dissolved solid (TDS) content and thus can serve as a CBM produced water treatment in addition to beneficial use of the impounded water.

Design of recharge ponds has five areas of specification: pretreatment, treatment, conveyance, maintenance reduction and landscaping. Pretreatment involves filtration or an interval to allow the sediment to settle prior to input into the recharge pond. Various treatments may be used to eliminate pollutants. Control of water flow and volume in the pond, pond size and spillway design falls into the conveyance category. Landscaping ponds increase the aesthetic appeal and may contribute to improved maintenance of slopes and reduced erosion. They often also improve local wildlife habitat. Because CBM development has the potential to draw down local aquifers, it is vital to maintain surface impoundments to support local water use.

***Recreation*—**Recreational use of large manmade water bodies has become an important secondary function of lakes and water sources created or expanded for urban and industrial water supplies. Fishing, swimming, boating and camping facilities are the most common recreational uses for impounded water. Coalbed methane water can be used to supply artificially constructed impoundments or supplement natural lakes during seasonal low periods. Wildlife habitat for migratory birds also may be classified as recreational use for hunters. A potential problem with constructing large recreational lakes is the relatively short-term nature (10 years to 20 years) of CBM development, which could result in water starved lakes.

***Evaporation Ponds*—**Evaporation ponds constructed in off-channel areas provide storage for CBM water. As evaporation occurs, the remaining water becomes concentrated into high TDS brine. The pond may need to be lined with bentonite clays to prevent water infiltration into the soil. In arid climates in the West, evaporation rates from 28 in. to 52 in. annually have been recorded. In the Gulf Coast region, evaporation rates may reach 48 in. to 70 in. per year. Evaporative ponds provide a relatively low-cost disposal method for CBM produced water if the proper stratigraphic layers of sediment are present. These include layers of sand and shales, which form impermeable seals or barriers to infiltration.

Constructed Wetlands—Wetlands are designated by saturated soil conditions, which determine the vegetation that may grow in a given region. Wetlands can be constructed in areas where frequent and long periods of soil inundation occur using CBM produced water to soak the site in arid off-channel areas. Wetland systems provide dual benefits as a means of naturally treating CBM produced water and to enhance and increase wildlife habitat. Wetland construction requirements are specific to locality but in general require a gentle gradient to prevent water runoff and soils with silt, loam, clay and fine sand that are able to hold water. Plant species should be selected given consideration to the local climate, tolerance levels to possible TDS concentration in the CBM produced water, and their value as food and habitat for fish and wildlife. Early stages in wetland construction and the resulting increased vegetation are shown in Figure 2.

Figure 3: *Local soils, pasture and agricultural needs must be considered before setting up coalbed methane irrigation systems.*

Surface discharge

The release of CBM produced water into surface water may be considered a beneficial use to augment stream water flow. The key to surface discharge is management of discharge amounts, timing and impact on the surface streams. The Clean Water Act requires permits for all water discharges. Permits to discharge water, including CBM produced water, specify the requirements on each site including volumes of water, TDS content and the body of water receiving the discharge. The effluent content of water discharged must be determined prior to discharge, and the period of discharge time is controlled to protect seasonal requirements of local streams, fish and wildlife. Surface discharge of CBM produced water can be intertwined with water rights issues. After discharge, the water becomes part of the "waters of the state" and is subject to all regulations applicable to surface water. Federal, state and Indian lands water rights must be considered for any use of the water once it has been discharged into a stream.

Individual states have specific regulations for discharge of water, which were discussed in article 2 of this series. Some of the typical considerations require:

- characterization of the stream;
- the total maximum daily load of pollutants in a stream segment;
- the base flow;
- the biological environment potentially affected;
- the primary source of water;
- the type of point source for any pollutants;
- the size and type of stream (perennial, intermittent or ephemeral); and
- the effect of snowmelt on stream flow.

There are three methods of surface discharge: discharge to surface water; discharge to land surface, with possible runoff; and discharge to land surface, with possible infiltration into subsurface aquifers. Direct discharge by pipelines avoids the potential erosion affects of open-channel discharge. Erosion causes local problems and increases the sediment load of the stream. The volume of direct discharge must also be considered so abrupt changes in the height of the water in a channel does not cause adverse effects on plant life, bank stability, aquatic vegetation, fish or invertebrates – all of which have particular depth and flow requirements.

Water discharge to land surfaces is commonly used for irrigation. Center-pivots, side-rolls and fixed or mobile water guns are irrigation systems used in the arid western states to spread water over a maximum area. All three have been used with CBM produced water in the Powder River Basin of Wyoming. Figure 3 shows the side-roll irrigation system.

Discharge of CBM produced water to surface impoundments having the potential of infiltration into subsurface aquifers requires determination of on- or off-channel water bodies. On-channel discharge includes ponds or dry drainages managed to encourage infiltration into alluvial channel fill. The volume and TDS content of the CBM water can easily be monitored. Discharge into off-channel constructed containment structures is designed to reduce the volume of produced water through infiltration and evaporation, leaving remaining water for beneficial use like stock or wildlife watering or fisheries.

Agricultural Uses— In addition to livestock and wildlife watering, CBM produced water for crops or to support pasture growth is an effective use in the arid western states where CBM produced water is normally high quality. Agricultural water sources in the west are limited by low rainfall and snowmelt, normally a cumulative amount of less than 20 in. per year. The runoff into ephemeral streams is seasonal, and marginal dry land farming can be improved with increased water supplies. Storage of CBM produced water in impoundments can alleviate the seasonal problems and provide irrigation water as needed for crops.

Coalbed methane produced water often has high sodium adsorption ratio (SAR) values – the ratio of sodium, calcium and magnesium concentrations – high concentrations of metals – iron, manganese and barium – and variable salt content. These minerals may affect soil permeability or be toxic to certain plant species. Ideal conditions for CBM produced water for irrigation are areas with coarse-textured soil and salt-tolerant crops. Several studies have been conducted and comparisons made to other arid parts of the world to identify the plants best suited to CBM irrigation.Use of salt-tolerant species utilizing CBM produced water is a land management option. Cooperation with CBM producers, land owners and mineral rights holders is necessary to optimize management of produced water for agricultural uses.

The suitability of saline water for irrigation is dependent on numerous factors, including the type and relative abundance of ions in solution, soil texture and mineralogy, sensitivity threshold and growth stages of plant species, as well as the amount of CBM produced water during each irrigation event. Plant sensitivity research can be used to select agricultural crops, which grow in areas of limited rainfall, colder temperatures and shorter growing seasons found in most of the Rocky Mountain states. The U.S. Department of Energy-sponsored studies at Montana State University have found barley, wheat, sugar beets, sorghum and cotton are best suited to irrigation by CBM produced water in the Powder River Basin. Native high salt-tolerant grasses and forbs can be planted around impoundments and discharge sites to maximize the use of CBM produced water and reduce erosion, as well as being used in bioremediation of brine contaminated soils.

Irrigation in the Powder River Basin using CBM produced water began in the 1990s. However, produced water from coalmines in portions of the Powder River Basin has been used for livestock and human consumption for more than 100 years. Sprinkler systems are used to provide a slow discharge of water over a wide area. Selection of the best irrigation system for a given area looks at several criteria:

- soil type (infiltration rate);
- system size or length;
- sprinkler head and capacity (spray nozzle or oscillating);
- area of coverage;
- elevation differential from pivot point to end of system;
- water pressure (pump capacity);
- speed of rotation; and
- peak daily evaporation.

Flood irrigation, using a series of constructed channels to divert water to native grass pastures, also has been applied. One advantage of flood irrigation is that less water is lost through evaporation, but it is more difficult to spread the effects of the water over wide areas.

Mixing CBM produced water with natural runoff may improve the quality of irrigation water. Use of on-channel and off-channel impoundments for storage and mixing can improve the suitability of irrigation water by balancing the levels of salts and mineral in subsurface and surface waters. Soil amendment procedures may be used to improve soils prior to irrigating with CBM produced water. Additives include cultivating gypsum or sulfur compounds into the soil to reduce clays and minimize the precipitation of calcite. Cultivation further encourages the growth of microbial bacterial, which are beneficial to the soil when sufficient water is available.

Industrial use

Water management options for CBM produced water include use in the operational activities of industries in the producing region. Common industrial uses include coal mines, animal feedlots, cooling towers, car washes, enhanced oil recovery and fire protection.

Coal Mines— As CBM produced water is frequently available close to coal mining operations, coalmines are a prime industrial user of CBM produced water. Coalmines can use CBM water for drilling operations, dust abatement, support on conveyor belts, crushing and grinding, assistance in restoring abandoned mine sites, and preventing spontaneous combustion of coal in the subsurface and storage areas.

Animal Feedlots—Using CBM produced water for animal feedlots has two applications, livestock watering and management of animal wastes. Water is used to dilute animal wastes prior to discharge or disposal. The U.S. Environmental Protection Agency regulates the disposal of animal waste streams based on the number of animals held in a given facility. If the pollutants are discharged into navigable waters, the waste stream must be reduced to specified limits by adding fresh water.

Cooling Towers—Numerous industries, chemical plants and municipal power generating plants require large quantities of water as a cooling agent. Cool water enters the system and is recycled through heat exchanges and cooling ponds, removing heat generated by the activities of the industrial complex. Constant input of water is necessary because of loss by evaporation. Only CBM produced water with relatively low TDS content can be used because high TDS content could result in mineralization, which would clog the cooling system.

Figure 4: *This figure shows a pond in the Powder River Basin supplied by coalbed methane produced water that facilities wildlife and recreational uses.*

Field and Car Wash Facilities—Construction activities require washing vehicles to avoid spreading noxious plants to other areas. This is particularly important when equipment is being used for reclamation of disturbed sites. Field sites and car washes in rural areas can be supplied with CBM produced water. Because there is a discharge of water to the soil, only CBM produced water with acceptable TDS and SAR levels can be used for this purpose.

Enhanced Oil Recovery— When oil and gas fields are in proximity to CBM producing areas, the use of produced water from CBM activities for waterflooding or secondary recovery is possible. Waterfloods are a common practice that can be performed with varying quality water and may be able to use low-quality CBM produced water.

Fisheries—Commercial fisheries in the western United States obtain water rights to divert water into their operational ponds from surface waters, and CBM produced water could be economically used in place of diverted surface or groundwater. This option is applicable if the fisheries are in or near the CBM fields where water can be easily transported or accessed through natural drainage systems. The water must be of sufficiently high quality not to be toxic or hazardous to the fish.

Fire Protection—Supplies of water for nearby municipal fire hydrants and sprinkler systems are a valuable use of CBM produced water. Fighting fires does not require high quality water and could benefit from the use of CBM produced water by not depleting drinking water supplies. Wildfires in the western United States are becoming larger and more dangerous because of the drought conditions that exist in many states, and normal supplies of water for fire fighting are becoming depleted. Supplies of CBM produced water stored in impoundments could provide accessible water for fighting fires in remote western areas.

Other Industrial Uses—In some of the western states, CBM produced water is beginning to be used in industries like sod farming, solution mining for minerals, production of bottled drinking water and water for breweries. Sod farming using CBM produced water in the San Juan Basin is helping supply the public's increasing demand for sod in new developments in municipal areas. Uranium mines in Wyoming are using CBM produced water in solution mining of uranium ore, and companies in Nebraska, Texas and Oklahoma have submitted permits for similar operations. Some CBM produced water already falls into the range of bottled drinking water and can be sold in stores, while other CBM water would require minimal treatment to make it suitable for drinking water. Drinking water quality CBM water can be used in breweries, and less high-quality CBM water can be used to irrigate barley, hops and other grains used in the manufacturing process.

Domestic and Municipal Water Use—Coalbed methane produced water that meets drinking water standards can be used for public, residential and municipal water use and supply. Many of the western states have a rural population in which individual landowners could benefit from a residential supply of CBM produced water, while other states have large municipalities in or near existing and potential CBM development. Coalbed methane produced water may also be used for watering lawns and in swimming pools, washing machines and plumbing.

Conclusions

Many coalbed natural gas operators are pursuing beneficial uses for CBM produced water where they are producing. The developers are undertaking a variety of new water management feasibility studies for new uses for CBM produced water that meet state and federal regulations and provide cost-effective water management for the CBM producers as well as low-cost, readily available water for public, residential and industrial uses. The handbook provides several case studies, which discuss strategies used for managing CBM produced water in the western United States. The strategies often employ a combination of several methods including impoundment, livestock and wildlife watering (Figure 4), irrigation and dust abatement. ✧

Acknowledgement

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Multi-Seam Well Completion Technology: Implications For Powder River Basin Coalbed Methane Production

By John R. Duda, U.S. Department of Energy, NETL

The Powder River Basin coalbed methane (CBM) play is in northeastern Wyoming and southeastern Montana. Covering 12,000 sq miles, the CBM play encompasses parts of seven counties in the two states and targets natural gas locked in Tertiary-age Fort Union Formation coals (see map). Depths for the play range from 300ft to more than 2,500ft and include a series of distinct coal seams, including the Anderson, Wyodak and Big George.

During the past 5 years, CBM development has increased in the basin. As of July 2003, nearly 1 Bcf/d of natural gas and 1.5 million bbl of water were being produced from about 12,000 wells.

More than 3,000 additional wells have been drilled but await utility and gathering line hookups and water discharge permits, among other things.

Thus far, development has generally targeted the shallow, thick, easy-to-reach coal seams along the eastern edge of the basin. However, with depletion of geologically more favorable areas, development is moving toward the deeper and somewhat thinner coals in the central and northern portions of the basin. In these areas, single-seam well completion technology may no longer prove adequate.

Coalbed methane operators in the Powder River Basin have long recognized the potential utility of multi-seam completions (MSC). Several operators have highlighted areas where such technology would be advantageous or vital for further development. A handful of operators have tried MSC. Because of the unique geological and reservoir properties of Powder River Basin coals – shallow, underpressured, low-rank (low strength) coals surrounded by water-bearing aquifers – the application of MSC technology has been largely unsuccessful.

Task description

At the request of the U.S. Department of Energy (DOE), Advanced Resources International Inc. undertook an analysis designed to evaluate the potential impacts of MSC technology for CBM development in the Powder River Basin. The study was a natural outgrowth of an earlier DOE analysis, which evaluated the economic impacts of produced water management alternatives on CBM development in the basin.

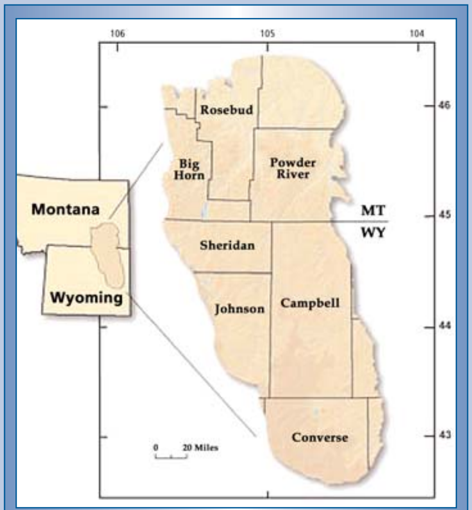
Objectives of the MSC study include:

- to estimate how much additional CBM resource would become accessible and technically recoverable, compared with drilling one well to drain a single coal seam;
- to determine whether there are economic benefits associated with MSC technology utilization (assuming its widespread, successful application) and if so, quantify the gains;
- to briefly examine why past attempts by Powder River Basin CBM operators to use MSC technology have been relatively unsuccessful; and
- to provide the underpinnings to a decision as to whether an MSC technology development and/or demonstration effort is warranted.

Summary of findings

The Powder River Basin has numerous sequences of "thin" coal seams that extend over major areas of the basin, particularly along the northern portion of the basin and in Montana. Whenever these thin (<20ft thick) coals and the natural gas contained therein are considered in the context of recoverable resources, the volume of technically recoverable natural gas significantly increases.

More importantly, development, adaptation and widespread application of MSC technology is expected to significantly improve the economics of CBM development in the Powder River Basin.



The Powder River Basin is in the northern Rocky Mountain region.

The revised outlook for CBM in the Powder River Basin is as follows (assuming widespread and successful application of MSC technology):

- the gas in-place, including thick coals and thin (< 20ft) coal seams, is estimated at 75 Tcf;
- the technically recoverable coalbed methane resource is estimated at 50 Tcf;
- the economically recoverable CBM resource is estimated to range from 24 Tcf to 38 Tcf (assuming $3.50/Mcf at Henry Hub and two basis differentials).

In both scenarios, the volume of economically recoverable CBM increases by 21 Tcf (vs. resource development via single-seam well completion methods); federal and state revenues would significantly increase. Royalty payments are estimated to increase by $3.6 billion and tax (severance and ad valorem) receipts are estimated to increase by $4.1 billion;

- MSC technology seems essential for developing the CBM resource in Montana and on Native American lands, areas that contain an abundance of natural gas in thin coal seams.

These results illustrate MSC technology can help improve the outlook for CBM in the Powder River Basin by increasing reserves per well and decreasing unit costs.

The full report and further information on this topic can be obtained from the NETL Web site at ***www.netl.doe.gov***

The department recognizes that in addition to technology, other actions, such as improved market access, are required to optimally develop this major natural gas resource. As such, the DOE remains committed to working with other federal and state agencies, and though public/private partnerships to facilitate responsible development of domestic sources of clean-burning natural gas. ●

References

Powder River Basin Coalbed Methane Development and Produced Water Management Study (November 2002), DOE/NETL-2003/1184

Multi-Seam Well Completion Technology: Implications for Powder River Basin Coalbed Methane Production (September 2003), DOE/NETL-2003/1193

Related Links

Bureau of Land Management Buffalo Field Office — http://www.wy.blm.gov/bfo/
Bureau of Land Management Miles City Field Office— http://www.mt.blm.gov/mcfo/
Montana Board of Oil and Gas Conservation— http://.bogc.dnrc.state.mt.us/
Montana Bureau of Mines and Geology— http://www.mbmg.mtech.edu/
Montana DEQ— http://www.deq.state.mt.us/coalbedmethane/index.asp
U.S. Environmental Protection Agency, Region 8—
http://www.epa.gov/region08/water/wastewater/wastewater.html
Wyoming DEQ— http://deq.state.wy.us
Wyoming Oil and Gas Conservation Commission— http://wogcc.state.wy.us
Wyoming State Geological Survey— http://www.wsgsweb.uwyo.edu/

Tight Gas Sands Development–How to Dramatically Improve Recovery Efficiency

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Integrated application of joint DOE/NETL and industry-sponsored intensive resource development technology could double the volume of natural gas considered technically recoverable from tight gas sands in Rocky Mountain basins. This is the first of a three-part series.

Three case studies are presented in this article to demonstrate the application of Intensive Resource Development (IRD). The first case study discusses how IRD is converting the Williams Fork/Mesaverde gas play in the **Rulison** field of the southern Piceance Basin of Colorado from a modest 100 Bcf accumulation into what is potentially a multi-Tcf gas field. The second case study examines the application of IRD in the **Jonah** field of the Greater Green River Basin of Wyoming, a field once labeled uneconomic and now the No. 1 producing field in the basin. The third case study describes how application of the lessons learned from the IRD experience in the Rulison field has helped change the **Cave Gulch/Waltman** field in the eastern Wind River Basin of Wyoming from a "four-well prospect" into a major gas field. One common thread in these examples is that the technologies and insights applied in each grew out of research and development (R&D) efforts supported by the U.S. Department of Energy/National Energy Technology Laboratory (DOE/NETL) during the 1980s and early 1990s.

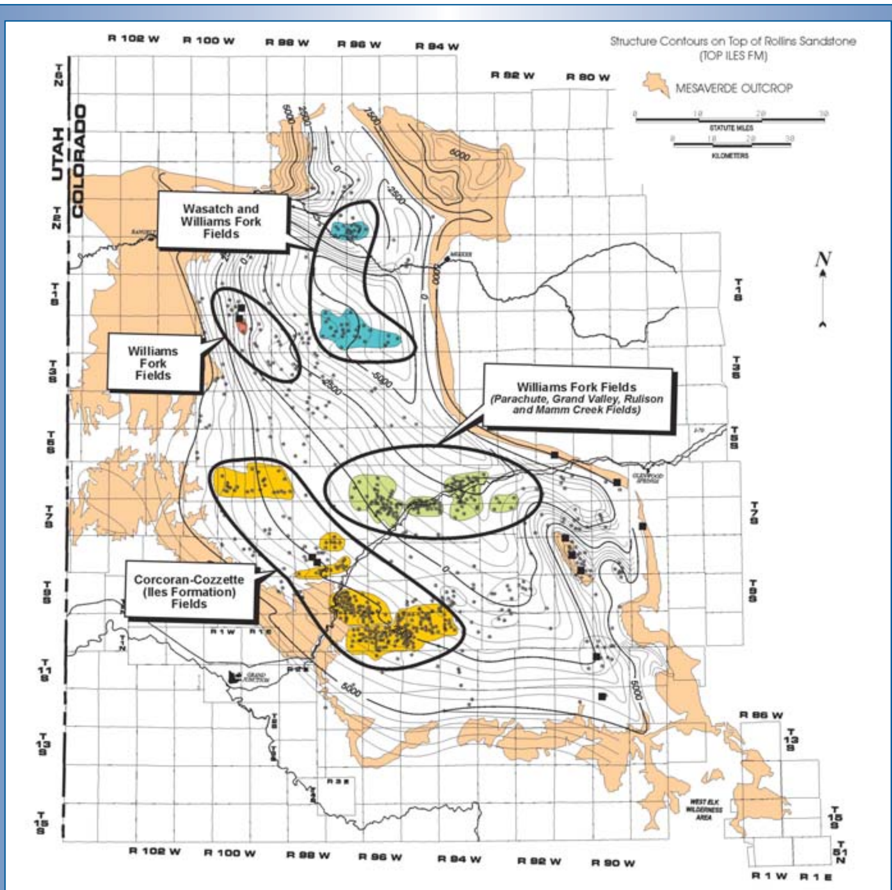

Figure 1. *Gas fields in the southern portion of the Piceance Basin are experiencing active tight gas sands drilling.*

This three-part series of GasTIPS *articles on tight gas sand resource development focuses on the application of advanced exploration and production technology in low-permeability sandstone reservoirs to increase domestic natural gas supplies and lower their finding and production costs. IRD is the integrated application of a series of complementary resource assessment, reservoir characterization and field development technologies designed to optimize recovery. It is particularly applicable to low-permeability reservoirs with thick but discontinuous pay zones and anisotropic flow behavior – settings where a well's drainage area is low but numerous productive intervals are penetrated.*

The suite of technologies IRD encompasses includes:

- *natural fracture identification technologies* to delineate high-productivity sections within a multi-township tight gas accumulation;
- *well logging technologies* that reliably distinguish between gas- and water-bearing sands, and can identify and quantify volumes of secondary porosity;
- *multi-zone completion technologies* that can efficiently stimulate multiple zones without damaging a formation; and
- *well testing technologies* to establish drainage volumes, well-to-well communication and anisotropic flow patterns.

NETL Intensive Resource Development R&D

The DOE/NETL sponsored three major research and development (R&D) activities in the Piceance Basin during the 1980s that helped establish a foundation for IRD technology. First was a series of resource assessments for the Piceance, Greater Green River and Wind River basins completed during a 15-year period (1980 to 1995). These assessments drew attention to large, high-concentration, Cretaceous-age unconventional gas accumulations and established the need for their thorough characterization. The National Energy Technology Laboratory (NETL) recently completed reassessments of the Greater Green River and Wind River basins, and is working on the Uinta and Anadarko basins (see *GasTIPS* Summer 2002, Vol. 8 No. 3).

Second was the Multiwell Experiment (MWX) in the southern Piceance Basin. This R&D project produced a comprehensive, well-documented description of the geologic controls on gas productivity in the Williams Fork and Iles Formations of the Mesaverde Group.

The third effort was an initial field test and demonstration of geomechanical-based natural fracture prediction technology in the **Rulison** field of the southern Piceance Basin. This test drew on prior work at the MWX site to develop technology for locating the higher productivity areas within tight gas sand accumulations. While these U.S. Department of Energy (DOE)-fostered research efforts were not the only drivers for the development of IRD technology, they were important catalysts.

The MWX in the Rulison field in Garfield County, Colo., began in 1980 and was completed in 1988. Three vertical wells, (**MWX-1, 2** and **3**) were drilled only a few hundred feet apart to provide a "laboratory" for production and stimulation experiments. The bulk of the work was performed in MWX-1, with holes two and three serving as observation wells for interference tests. An additional slant hole well was completed in 1990 as part of a joint DOE/Gas Research Institute (GRI) field research project.

The wells targeted the Mesaverde Group, Iles and Williams Fork Formations, which together encompass four different depositional environments. A geologic characterization of the Williams Fork Formation established that the sand bodies are compartmentalized fluvial point bars, with extremely tight matrix permeability (<0.0001 milidarcies) with an abundant system of micro-scale natural fractures and a less frequent set of macro-scale natural fractures, requiring hydraulic stimulation to interconnect this dual-fracture system with a wellbore. To obtain more reliable data on the natural fractures – defining vertical fractures is difficult with a vertical well because of the low probability of intercepting a vertical plane with a vertical hole – the DOE/GRI slant well was drilled at an angle of 60° to 85° from vertical.Two interval were cored, and the strike, dip and spacing of 65 fractures were recorded in the 381ft of retrieved core. These natural fractures, oriented west-northwest, were vertical and terminated within or at the boundaries of the sandstone beds. Well tests showed flow was primarily through these natural fractures with little occurring transverse to the fracture orientation.

Present-day stress conditions in the Mesaverde dictate hydraulic fractures initiated from a wellbore will have the same general orientation as existing micro-scale natural fractures, thereby lessening the chance of linking the wellbore with this system of natural fractures. However, areas where local faulting has tectonically altered the stress field and created large-scale natural fractures orthogonal to the micro-scale fractures will contain more favorable flow paths from reservoir to well.

The MWX also established a full set of reservoir properties for the Mesaverde Group formations, an achievement that went a long way toward improving methods for completing and stimulating these tight gas reservoirs. Continuous core and a full suite of logs and well tests across the stacked pay zones provided detailed pressure, porosity, permeability and saturation data. The well tests showed limited well-to-well communication, and modeling of the pressure response suggested permeability anisotropy ratios of 50:1 with bulk permeabilities of 1 microdarcy to 15 microdarcies.

The composite reservoir model that emerged from the MWX field experiment revealed a complex geologic and reservoir setting with vertically stacked point-bar deposits separated by alternating layers of shale that naturally isolated individual reservoirs. The combination of isolated point bars and the preferred natural fracture distribution could be shown to lead to elliptical drainage patterns.

The MWX project provided key insights to the nature of the tight gas sand reservoirs in the Rulison field that helped establish the foundation for the IRD technologies being applied in tight gas sand reservoirs of the Southern Piceance Basin – particularly those in the Williams Fork Formation – and elsewhere in the Rockies. Williams Production RMT is using the results from the MWX site to obtain Colorado Oil and Gas Conservation Commission approval for 10-acre and 20-acre per well spacing rules at Rulison and adjacent fields. The MWX project is a good example of the DOE-sponsored research providing the basic data and analytical foundation for interpretations the industry would not otherwise make the investment to acquire. ●

Case Study No. 1—Southern Piceance Basin, Colorado

The Piceance Basin is in northwest Colorado. Gas fields in the southern portion of the basin (Rulison, **Grand Valley, Parachute** and **Mamm Creek**) are experiencing active drilling for tight gas sands in the Upper Cretaceous-age Mesaverde Group (Figure 1). Historically, the tight lenticular Mesaverde sands in the Williams Fork have been viewed as a massive but low-productivity natural gas resource. However, field-based research has provided a more rigorous geologic understanding of these tight gas reservoirs and the appropriate technologies for producing them.

The Mesaverde tight gas sands in the Piceance Basin are estimated to hold more than 300 Tcf of gas. This resource is most highly concentrated in the southern portion of the basin, particularly in the stacked, lenticular sands of the Williams Fork Formation being developed in the Rulison field. In recent presentations to the Colorado Oil and Gas Commission (COGC), Williams RMT concluded the gas-in-place per section was 135 Bcf at Rulison, 120 Bcf at Parachute and 105 Bcf at Grand Valley. At traditional well spacings of 160 acres per well (four wells per section), 5% to 6% of this resource is in contact with a wellbore and recoverable. Based on the results of the MWX research (see sidebar), two new IRD strategies have been pursued in the Rulison field: intensive infill drilling and extensive vertical sand development. As documented in Barrett Resources and Williams RMT submissions to the COGC, these companies credit the DOE/NETL-sponsored MWX and its other R&D projects for developing the knowledge base and science for much of the IRD technology at Rulison field.

Geologic Basis for IRD Strategy—Outcrop studies of the lenticular Mesaverde sands have shown that wells separated by only 1,000ft will not be in communication, except in a handful of the more continuous sand intervals. Wells spaced as close as 1,100ft (28 acres per well) show little to no pay correlation from well to well (Figures 2 and 3). Even the three closely spaced MWX wells

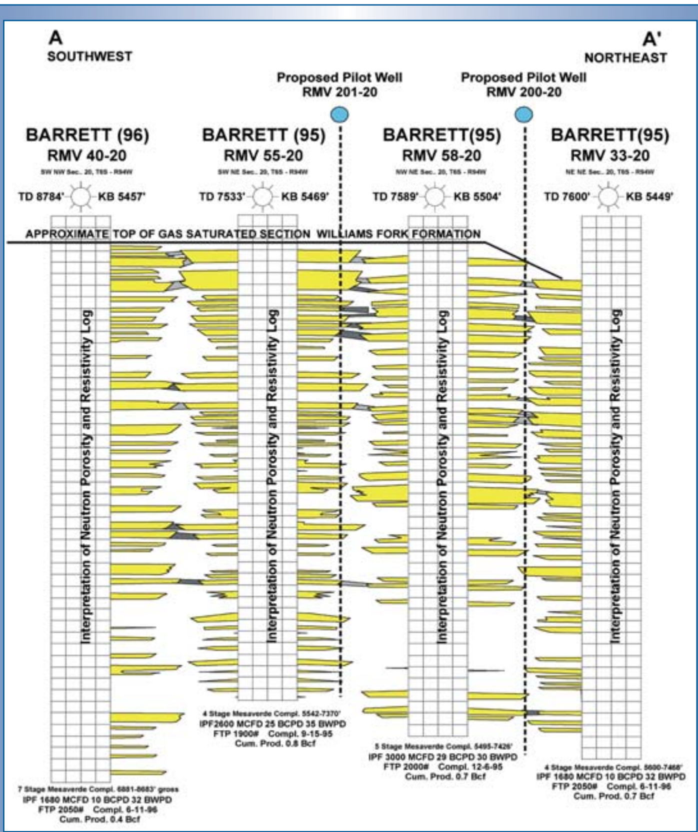

Figure 2. *Even closely spaced wells often show little continuity.*

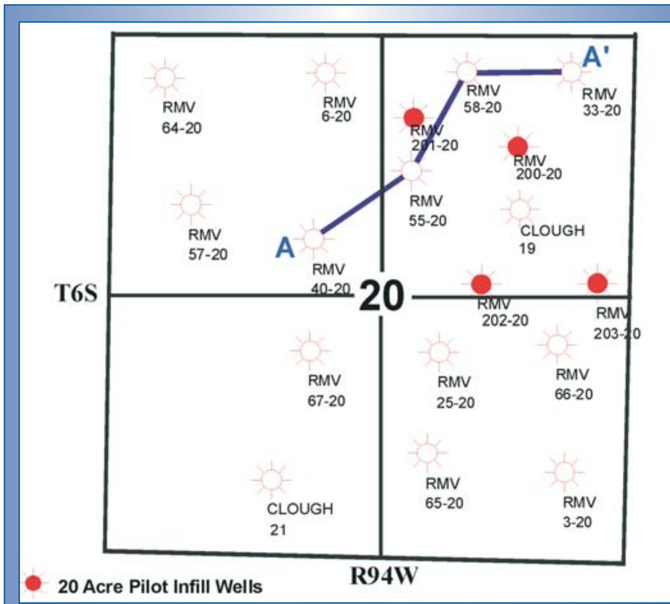

Figure 3. *This figure shows the location of the cross-section outlined in Figure 2.*

(about 150ft apart) showed poor well-to-well log correlation for the Williams Fork lenticular sands (Figure 4). Reservoir simulation (by Barrett Resources and Advanced Resources International) incorporating the low magnitude, anisotropic permeability and compartmentalized geometry of the lenticular Williams Fork sand bodies, has shown such wells have limited areal drainage. These studies helped operators view the Williams Fork as primarily a vertical rather than areal reservoir. This led operators to pursue more intensive development – closer well spacing and completion of all potentially productive sand intervals – than had been traditional in the Piceance Basin.

***Infill Well Tests Support Tighter Spacing*—**Well tests also supported the idea of limited communication. During the initial infill-drilling program at Rulison, bottomhole pressure tests on new wells drilled adjacent to highly productive older wells showed essentially no communication-related depletion. More recent bottomhole pressure build-up data Barrett Resources performed on 80-acre and 40-acre spaced wells in 1994 and 1995, and subsequently on 20-acre spaced wells drilled in 1996 at Rulison and Grand Valley fields, indicated essentially no well-to-well pressure communication.

***Reservoir Simulation and Analyses Quantifies Benefit*—**Type curve matching performed on a series of representative Mesaverde tight sand wells in different portions of the Rulison field showed the average outer limit of pressure depletion for a typical 1.8 Bcf well in the Williams Fork, after 20 years of production, is about 12 acres. Reservoir simulation and production data showed that traditional 160-acre spacing wells would only recover about 7% of the gas-in-place, but this value would climb to 21% at 40-acre spacing. Modeling also showed that when permeability, anisotropy and depositional direction are accounted for, drainage takes on a preferential east-west direction, calling for wells to be spaced on a rectangular rather than a square grid.

***Barrett Infill Program Shows IRD Benefit*—**The traditional field development practice for the Williams Fork (Mesaverde) Formation had been to space wells at 160 acres or more. In 1994, Barrett Resources took the initial steps toward IRD, requesting approval for first 80-acre and then 40-acre spacing from the COGC. In 1996, Barrett requested approval to drill four wells in a 20-acre spacing pilot. The 20-acre spaced wells performed as well as the older, more widely spaced offset wells. Based on these promising results, the field operator continued with its intensive infill-drilling program. Twelve new infill wells were drilled in Section 20 of the Rulison field between 1998 and 2000, bringing the section total to 30 wells (effectively 20-acre spacing). The performance of these wells continued to be encouraging, with initial gas rates of 1 MMcf/d to 2 MMcf/d and estimated ultimate recoveries of 1.4 Bcf to 2.5 Bcf per well. Analysis of currently available data shows:

- the reserves per well remained relatively constant as the well density in Section 20 has progressively increased, indicating additional gas is being recovered vs. faster depletion; and
- intensive development of the Williams Fork sands at 20 acres per well may result in the recovery of 50 Bcf to 60 Bcf of gas reserves from this single section. Based on previous experience, bottomhole pressure testing on the 20-acre spaced wells at Rulison revealed that

only three of the 72 sands tested in the four wells exhibited pressure communication and possible partial pressure depletion.

The field operator (now Williams Production RMT) took the IRD concept to the next level by applying for permission to drill Section 20 in the Rulison field, and an additional section at Grand Valley field, at a spacing of 10 acres per well. Starting in late 2001 and continuing through early 2003, the operator added 10 additional infill wells to Section 20, bringing the total to 40 wells. While production data are still limited and several of the wells are still cleaning up, preliminary analysis shows the most recent group of wells have exhibited initial production rates of 1 MMcf/d to 2 MMcf/d, comparable or superior to the previously drilled 20-acre and 40-acre spaced wells. Seven of the 10 wells, after about 1 year of production, have performed such that their ultimate recoveries can be estimated in the range of 2 Bcf per well. Pressure testing in the newly drilled 10-acre spaced infill wells detected partial reservoir pressure depletion in six of 98 individually tested sand bodies. The total gas recovery from this section of the field, albeit with favorable reservoir properties and a high concentration of gas in-place, is expected to be more than 100 Bcf per section if fully developed with 64 wells (Table 1). Based on estimates by Williams, gas recovery in this section may reach 75% of gas-in-place vs. less than 10% on 160-acre spacing.

Vertical Completion and Restimulation—The lenticular sands in the Rulison field are separated into a series of packages, each of which comprise 400ft to 500ft of gross interval, and most wells penetrate four to six packages across more than 3,000ft of gas-saturated interval. Historical practice, given the difficulties with then-current log interpretation technology, had been to complete one or two sand packages to avoid wet, unproductive sands. This conventional practice resulted in per-well reserves averaging 0.5 Bcf, effectively rendering the wells and the gas play uneconomic.

Starting in 1994, Barrett Resources began to aggressively develop the total stack of lenticular sands intersected by each wellbore. The new approach included completing and independently stimulating each of the sand packages, increasing the size of the proppant load, and using more sophisticated fracturing fluids and procedures.

With improved core and log data, and a better understanding of lenticular sands, and basin-centered gas plays, Barrett also began to re-examine the potential for recompleting these older wells. An early recompletion demonstration took place in 1990 in the No. 1 well at the DOE's MWX field research site. The recompletion, which involved perforating and stimulating three additional uphole Williams Fork/Mesaverde sand packages, exhibited an excellent initial production response. As of early 2003, it had produced 1.4 Bcf of incremental production, validating this more aggressive recompletion approach. Following this demonstration, the operator launched a program to recomplete bypassed sands in older wells. Overall, the recompletion program has been successful, adding more than 80 Bcf of low-cost natural gas reserves. The cumulative effect of completing four to five pay zones in a single well and recompleting the older wells has been to raise the average well performance for new and old wells in Rulison field to 1.5 Bcf per well.

Based on the Rulison field example, IRD technology, with 10-acre well spacings and vertical completion of the full stack of sand, offers the promise of providing about 100 Bcf of recoverable resource per section and recovery of 80% of gas-in-place. IRD could transform a township-sized, basin-centered tight gas field from a 100-Bcf prospect into a major field with multiple Tcf of reserves. Other operators in the Southern Piceance Basin are applying the lessons learned at Rulison for optimally developing massively stacked tight sand accumulations in other Williams Fork Formation tight gas fields. Successful application of this technology holds

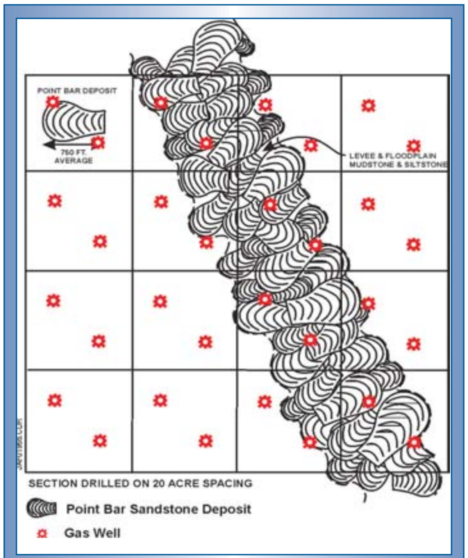

Figure 4. Outcrop studies have indicated the individual point bar deposits are in irregular vertical contact with the sequence of deposits that comprise the larger sand lenses in the fluvial channel.

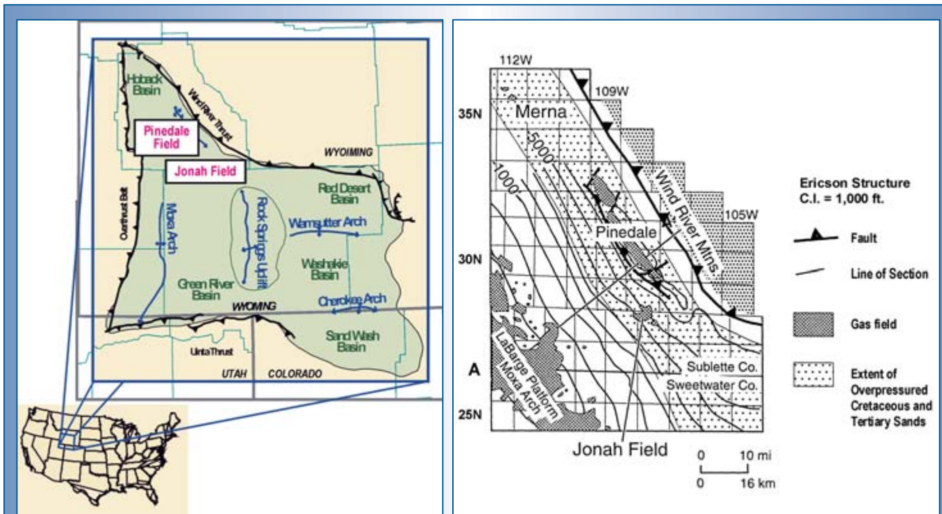

Figure 5. *The Lance Formation is emerging as a significant producing horizon in the Jonah and Pinedale fields in the Greater Green River Basin.*

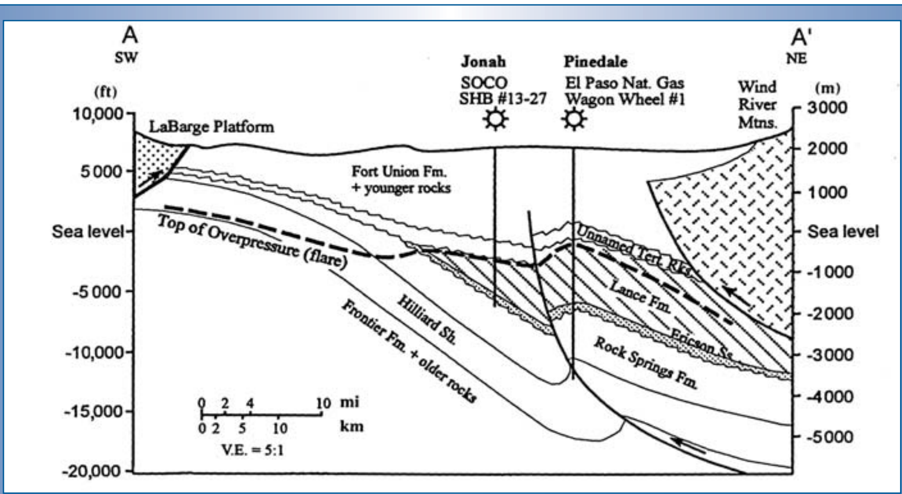

Figure 6. *This cross-section shows the Jonah and Pinedale fields relative to the surrounding tectonic features.*

the potential for converting this previously uneconomic tight gas play into a world class natural gas accumulation.

Case Study No. 2—Northwestern Greater Green River Basin, Wyoming

The Greater Green River Basin (GGRB) is the dominant natural gas-producing basin in the Rocky Mountains. Gas in this basin is found in the Tertiary and Cretaceous-age Fort Union, Lance, Mesaverde Group, Frontier, Muddy and Dakota formations. Recently, the 8,000-ft to 12,000-ft Lance Formation has emerged as a significant producing horizon in the Jonah and **Pinedale** fields in the northwestern portion of the GGRB. Development of an extensive stack of tight, over-pressured sandstones is underway in both fields (Figure 5).

The township-sized Jonah field is estimated (by industry) to hold nearly 10 Tcf of gas-in-place; a resource concentration of 250-Bcf to 300-Bcf per section. A unique geologic setting involving the local uplift of the over-pressured Lance section and a series of lateral sealing faults has enabled gas to accumulate and remain trapped in the Jonah field area (Figure 6).

Completion Inefficiencies Set the Stage for IRD—Prior to 1992, completion attempts employed relatively small amounts of proppant (80,000 lb to 200,000 lb) and cross-linked water-based gel or carbon dioxide foam as the transport fluid. These ineffective fracturing fluids, coupled with poor proppant placement, failed to establish commercial production. Between 1992 and 1995, nine wells were stimulated with high-quality nitrate (N_2) foam and an average proppant load of 550,000 lb. Most of these new stimulations, limited to the thicker (250ft to 300ft) sandstone intervals, resulted in successful wells but with steep annual declines in gas production. Engineering analyses of the wells completed using N_2 foam highlighted several factors that potentially limited well performance:

- significant vertical growth of hydraulic fractures outside of the pay interval;
- creation of multiple fractures with a resultant reduction in propped fracture length; and
- inefficient lateral transfer of proppant away from the wellbore.

Beginning in 1994, a new completion approach was initiated using water-based fluids with borate cross-linkers and a modified perforation technique designed for flexible treatment of multiple intervals. Wells where this new approach was employed exhibited initial gas flow rates comparable to the earlier completions but with shallower gas production declines, which, from improved lateral and vertical proppant placement, have led to greater ultimate gas recoveries.

With new well completion practices, gas production rates have improved significantly from an average of 2 MMcf/d to 3 MMcf/d, to 5 MMcf/d to 7 MMcf/d. One of the best "early" wells was found to be productive from as many as 17 separate sandstones distributed across all four lower pay intervals (Lower-Middle Lance) and has been completed in an additional 11 zones in the Upper Lance.

Evolution of IRD in Jonah Field—Aggressive vertical completion of the full stack of gas-charged net pay in the Lance Formation has

Table 1: *Expected results from intensive field development (Sec. 20, T6S, 94W, Rulison).*

Date	Wells and Spacing	Reserves/Well[1] (Bcf)	Total Gas Recovery (Bcf)
Initial	First 2 wells @320A/W	2.1	4
1994	Next 2 wells @160 A/W	2.2	4
1995	Next 4 wells @80 A/W	1.9	8
1996-1997	Next 8 wells @40 A/W	1.8	14
1997	Pilot 4 wells @20A/W	1.7	7
1998-2000	Next 12 wells @20 A/W	1.7	20
Latest	Next 32 wells @ 10 A/W	1.7	55
TOTAL (64 wells)		**1.75**	**112**

1. Estimated based on history matching with ARI-tight type curve model for wells drilled through 1997.

Table 2: *Evolution of well completion practices, Jonah field, Greater Green River Basin.*

	First Generation	Second Generation	Third Generation	Current
	Pre-1990	**1992-1993**	**1994-1995**	**2000+**
Pay Selection	Bottom 40%	Bottom 20-50%	50%	50% to 100%
Frac Stages	1	1	3	Up to 10
Frac Fluid	X-Link Gel	N_2	N_2/Gel	Borate Gel
IP (MMcf/d)	1.4	1 to 4	3 to 5	5 to 15
EUR (Bcf)	1.5	2.0	3.0	5 to 10+

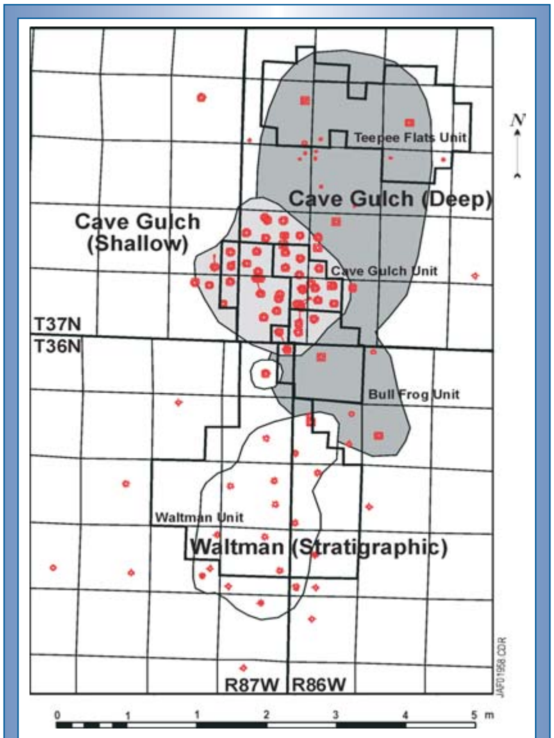

Figure 7. *Although the Cave Gulch field was discovered in 1959, only recently has it been recognized as a significant gas accumulation.*

converted the Jonah field from a bypassed area with low productivity wells to a highly productive giant gas field. The realization that past pay selection procedures were inadequate and past well stimulation practices were damaging led to changes in well completion practices (Table 2). The current IRD approach is to attempt to link a wellbore to as much of the vertical net pay as possible, using a dozen or more stimulations in individual Lance zones. With IRD, the estimated reserves per well in the Jonah field have increased from 1 Bcf to 2 Bcf per well in the early 1990s to 5 Bcf to 10 Bcf per well currently. As of mid-2003, Jonah is the largest natural gas field in the GGRB, producing 670 MMcf/d from 484 wells, compared with 15 MMcf/d in 1995. The field has produced more than 800 Bcf and is on its way to becoming a multi-Tcf gas field. Recently, the operators in the Jonah field and in the adjoining Pinedale area have begun development on 40-acre spacing, with indications of closer spacings to come. The coupling of intensive areal resource development with successful intensive vertical resource development should continue to improve the size and economics of this major new tight gas sand field.

Case Study No. 3—Eastern Wind River Basin, Wyoming

The Wind River Basin is one of the least developed of the high-potential natural gas basins in the Rocky Mountains. Gas in this basin exists in an extensive stack of Tertiary- through Cretaceous-age formations. Recently, the tight gas sands in the Fort Union/Lance Formation have become targets of active tight gas development. The primary Fort Union/Lance Formation natural gas fields in the Wind River Basin are **Frenchie Draw, Madden, Muddy Ridge/Pavilion** and Waltman/Cave Gulch. The largest of these, Waltman/Cave Gulch, is on the northeast flank of the basin, about 50 miles west-northwest of Casper, Wyo. (Figure 7). Although the field was discovered in 1959, the Cave Gulch Unit remained undeveloped and its true potential unrealized until Barrett Resources rediscovered it. For nearly 35 years, the Cave Gulch Unit was judged to be a modest, marginally productive natural gas field, having recovered less than 5 Bcf and producing only a few MMcf/d. Recognition that the Cave Gulch Unit held a massive stack of gas-saturated sands led to the application of IRD in this field starting in 1994.

The Bureau of Land Management (BLM) estimates the Waltman/Cave Gulch field area contains at least 1.6 Tcf of gas-in-place, primarily in a four-section area on the western edge of the field and in two sections on the eastern edge of the field. The BLM estimates the Fort Union and Lance Formations in this area contain an average 885ft of net pay within a 4,000-ft gross interval, holding from 450 Bcf to 680 Bcf per section. Assuming the reservoir sands are truly gas-(instead of water-) saturated, this would make the area one of the most highly concentrated natural gas accumulations in the Rocky Mountain region.

Evolution of Intensive Vertical Resource Development at Cave Gulch—Intensive vertical resource development, completing as much of the vertical sand interval as possible (between four and five stimulation stages per well on average) using large volumes of proppant (about 200,000 lb of sand per stage on average) has improved the performance of Cave Gulch wells. A total of 28 IRD wells completed between 1994 and 1998 exhibited initial flow rates as high as 10 MMcf/d, some with estimated reserves of 20 Bcf per well. Although there is considerable variability in the performance of the wells, particularly recent wells drilled along the edge of the Cave Gulch Unit, the average ultimate recovery for 43 successful Lance Formation IRD completions (excluding three economic dry holes) is estimated at 9 Bcf per well. The average of 18 successful, shallower Fort Union IRD completions in the Cave Gulch Unit is an estimated 5 Bcf per well, excluding four dry holes.

This example illustrates how the combined use of vertical development of the full stack of tight sands and optimum well spacing can lead to recovery of large volumes of natural gas from a relatively limited portion of the tight gas resource base. Together, these examples show how fundamental research and careful characterization of an apparently uneconomic resource by government and industry can reveal opportunities for new approaches to unlocking tight gas. ✧

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Gas Potential of Selected Shale Formations in the Western Canadian Sedimentary Basin

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A preliminary study by Gas Technology Institute evaluated the geochemical, geological and structural characteristics of the shale packages in the Western Canadian Sedimentary Basin.

Unconventional gas resources include coalbeds, shale formations and low-permeability sandstone. Gas from fractured shales is a burgeoning element of this unconventional gas mix. To better understand the exploration potential of this play, models have been developed that better characterize the geological setting and the geochemical framework of shale gas production in the continental United States. This study was conducted to better characterize the shale gas potential of five formations in western Alberta and eastern British Columbia – within the Western Canadian Sedimentary Basin (WCSB) – that conform to these models.

The formations of interest are the Upper Cretaceous Wilrich and equivalents, Jurassic Nordegg/Fernie, Triassic Doig/Doig Phosphate/Montney, Exshaw/Bakken and Devonian Ireton/Duvernay formations.

Geochemical data for this evaluation came from open file Geological Survey of Canada reports and data generated through this work.

A cumulative resource calculation for the Wilrich, Duvernay, Montney, Doig and Doig Phosphate formations suggests hydrocarbon volume to be on the order of 86 Tcf. However, the scope of the study did not allow detailed structural analysis of these areas.

Production scenarios will most likely be from areas with conventional source rock characteristics which grades to silt/sand units. Another scenario will rely on natural fractures in these tight units. In any case, the gas shale production experience from the United States shows that almost always, some stimulation techniques are necessary for gas shale production.

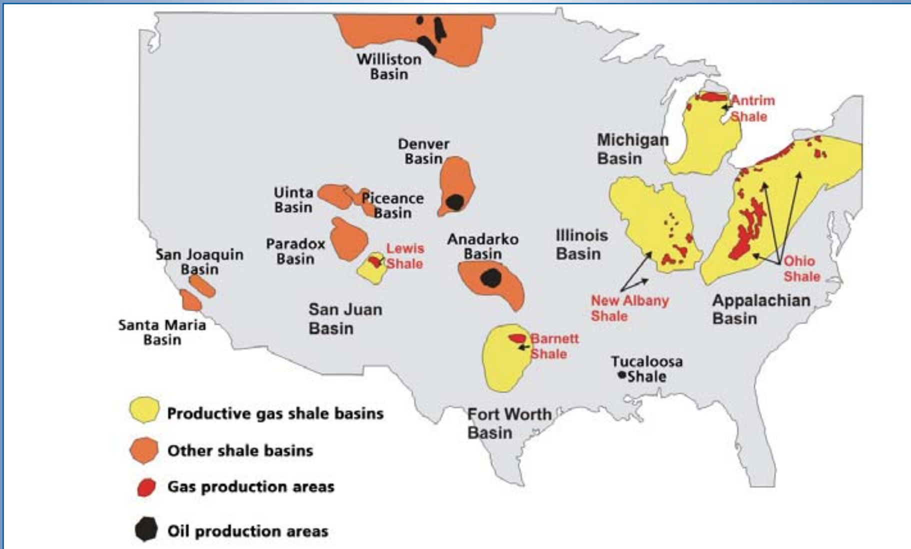

Figure 1. *Commercial shale production in the United States is concentrated in the Devonian, Mississippian and Cretaceous shale basins.* (Courtesy of the Gas Technology Institute)

Study objectives

It is anticipated that unconventional gas sources will also become a target of exploration within the WCSB in the near future. In particular, shale gas may offer considerable potential because of the extensive distribution of fine-grained clastics throughout the basin, spanning a broad geological time frame from the Devonian through the Cretaceous epoch.

To help provide further information on this potential, the Gas Technology Institute (GTI) study summarized here focused on a detailed organic geochemical review of the five promising shale gas zones. In particular, the study aimed to develop a better understanding of the source rock and reservoir potential of these shales in Western Alberta, in an area between Townships 1-72 and Ranges 23W4, to the border with British Columbia.

Overview

Commercial shale gas production occurs primarily in the continental United States. Areas of production are concentrated in the Devonian shale basins of the eastern United States, the Mississippian shale basin in Texas, and the Cretaceous shale basin of Colorado and New Mexico (Figure 1 and Table 1).

Historical shale gas production and resource estimates for the United States are shown in Table 2. Some key properties for these productive gas shales are listed in Table 3. Shale gas reservoirs typically have recovery factors of about 20%, compared to 75% for conventional reservoirs. Production is expanding (Figure 2). Renewed development of shale gas exploration in the United States was precipitated by the enactment of the Section 29 Non-conventional Fuels Production Tax Credit, implemented to encourage unconventional gas production in the late 1970s.

Shale gas plays are classified as "continuous" natural gas plays, i.e., accumulations that are pervasive throughout large geographic areas, offering long-lived reservoirs with attractive finding and development costs, according to the United States Geological Society. Continuous accumulations differ from conventional hydrocarbon accumulations in two important ways. First, they do not occur above a base of water, and second, they commonly are not density-stratified within the reservoir, according to the U.S. Department of Energy.

With more than 37,000 gas wells producing from five shale basins in the continental United States, shale gas is now recognized as a viable and economic resource.

Although there are no estimates of the shale gas potential in Western Canada, the WCSB has shale formations well suited to shale gas production. There is emerging evidence to suggest that shales, historically and currently, are contributing to conventional production. Within the WCSB, shale formations with gas potential occur throughout the geological record, from Devonian through Cretaceous time periods. A better understanding of the geochemical, geological and structural characteristics of the shale packages in the WCSB is essential in order to evaluate the shale gas potential in this region.

Shale gas overview

Traditionally, fine-grained rock units have been of interest as source rocks of hydrocarbons and as seals or cap rocks for hydrocarbon accumulations. Large volumes of hydrocarbons are known to have migrated from their sources into more porous and permeable reservoir rocks. However, shale source rock retains part of the generated hydrocarbons, thus acting as both source and potential reservoir. Natural fractures are also essential for a shale gas system to store hydrocarbons and to serve as permeable pathways for migration to the wellbore.

Shales are the most common type of sedimentary rock in the WCSB and constitute about 80% of the Phanerozoic record. The hydrocarbon generative potential of shales, and the presence of porosity and permeability to accommodate hydrocarbons, determine the potential for shale gas production from a formation or unit of interest. This permeability and porosity is achieved through localized natural fracture systems developed from structural influences in an otherwise competent package as well as through siltstone/sandstone laminae and stringers.

Storage of the gas occurs within these fractures, within matrix porosity and as an adsorbed phase on kerogen. Adsorption is the adhesion of a single layer or more of gas molecules to the internal surfaces of a coal or shale matrix. Up to 50% of the total gas within a coal or shale can be found as an adsorbed phase on kerogen; thus, the total amount and type of organic matter exerts a strong influence on the adsorptive capacity of shale.

Gas originates in source rocks by two main processes:

- as biogenic gas because of the action of anaerobic micro-organisms during the early diagenetic phase of burial or recent invasion of bacteria-laden meteoric water; and
- as thermogenic gas from the thermal breakdown of kerogen at greater depths and temperatures.

Factors that control the level of methane production after sediment burial are anoxic environment, sulfate deficient environment, low temperature, abundant organic matter and sufficient space for gas storage.

Biogenic gas generally forms at depths less than 3,300ft but can be preserved in reservoirs to depths as great as 14,850ft (Po Basin, Northern Italy). Biogenic methane also can form later in the rock's geologic history as the result of oxygenated ground water circulating through the rocks, usually at shallow depths of less than 1,800ft. Shallow biogenic gas produced in the Antrim Shale in the Michigan Basin is believed to have been generated during the past 22,000 years by such a microbial process of circulating ground water, according to the University of Michigan News and Information Services. The age-equivalent New Albany Shale in the Illinois Basin also produces biogenic gas, but it is not known whether circulating ground waters recently generated this biogenic gas or whether it is original biogenic gas generated shortly after the time of deposition. It is apparent that any organic-rich source shale is a potential gas shale, regardless of maturity level.

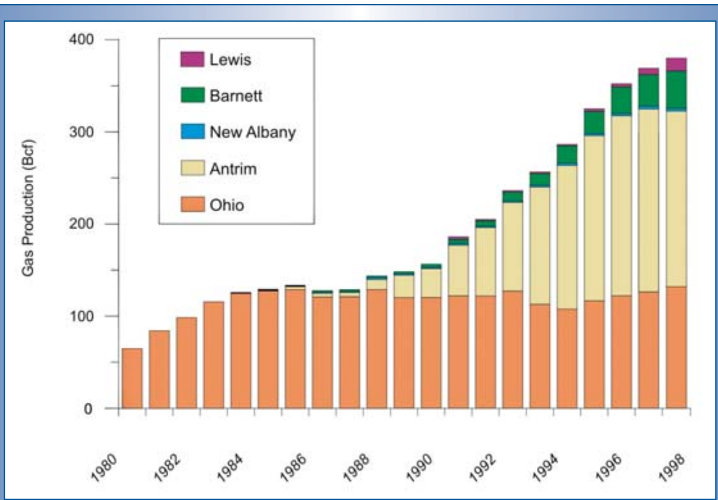

Figure 2: *Current production from gas shales accounts for about 3% of total gas production in the lower 48 states but is expanding.*

Shale gas reservoir characteristics

The major exploration risk in most shale gas plays is generally not drilling a truly dry hole but in not obtaining economically viable gas production rates. Most shales have low (microdarcy) matrix permeabilities and require the presence of extensive natural fracture systems to sustain commercial gas production rates. The natural gas is stored in three ways in the shales:

Table 1: *Additional fractured gas shale plays in the United States.*

Formation	Geologic Age	Basin
Bakken	Devonian-Mississippian	Williston
Cane Creek	Pennsylvanian	Paradox
Gammon	Cretaceous	Williston
Green River	Eocene	Uinta, Piceance
Mancos	Cretaceous	San Juan, Uinta
McClure	Miocene	Various California Basins
Monterey	Miocene	Various California Basins
Mowry	Cretaceous	Hanna
Niobrara	Cretaceous	Denver-Julesburg
Pierre	Cretaceous	Denver
Tuscaloosa	Upper Cretaceous	Gulf Coast
Woodford	Devonian	Anadarko

- free gas in the rock pores;
- free gas in the natural fractures; and
- adsorbed gas on organic matter and mineral surfaces.

These different storage mechanisms affect the speed and efficiency of gas production.

In general, characteristics of gas shale reservoirs include:

- low production rates (20 Mcf/d to 500 Mcf/d) but cover very large areas;
- wells have long production life (up to 30 years);
- decline rates are generally less than 5% per year (typically 2% to 3%);
- the ability to be thick (up to 1,500ft);
- gas shales are typically organically rich (1 wt% to 20 wt% total organic carbon);
- reservoirs contain large gas reserves (5 Bcf to 50 Bcf per section);
- reservoirs rely on natural fracture systems for porosity and permeability (matrix por/perm very low); and
- the requirement for stimulation (fracing) to be economic.

Conclusions and recommendations

The gas shale formations studied in the WCSB contain potentially large volumes of hydrocarbons. Organic rich shales have the potential to generate and store large volumes of methane, regardless of maturity level, because of biogenic gas generation during the early diagenesis stage and subsequent catagenic generation at higher levels of maturity.

Wilrich and Equivalent:

- These units are restricted to northern Alberta and northeast British Columbia.
- The Wilrich and Equivalents are characterized by generally poor source rock characteristics: low total organic carbon contents and gas-prone Type III kerogen.
- There is some potential for gas in interbedded tight sand and shale sequences, but these are difficult to predict.
- The Wilrich source characteristics are similar to the Lewis Shale in the San Juan Basin, but the Wilrich is thinner over a large area.
- The thicker marine shale sequence may provide the best potential for Wilrich Shale gas.

Nordegg, Fernie, Poker Chip and Rock Creek:

- The Jurassic Fernie Group contains several units with varying hydrocarbon source rock potential. The most prolific is the Lower Jurassic Nordegg Member, which is comprised of relatively thick, high-total organic carbon-content shales across large portions of the WCSB.
- Although the Nordegg Member unit is oil-prone, it does appear to have good shale gas potential, especially in mature (and probably biogenically charged), naturally fractured areas;
- the Poker Chip Shale unit overlies the Nordegg and exhibits low to moderate total organic carbon contents. Gas from this shale zone could be produced from highly fractured areas but is most likely to be viable if co-produced with other units of the Fernie Group.
- The Rock Creek Member is usually considered a conventional sandstone target, but gas charging from the shale units in which it is encased should also provide exploration targets in its fractured silty facies.

Table 2: *U.S. gas-bearing shale resources.*

Basin	State(s)[1]	Formation	Basin Area	Total Organic Carbon	Thermal Maturity	Shale Gas-In-Place Resource		Estimated Recoverable Shale Gas Resource		Estimated Total[2] Undiscovered Gas Resource
			(sq mi)	(wt%)	($\%R_o$)	(Tcf)		(Tcf)		(Tcf)
Appalacian	OH, KY, NY, PA, WV, VA	Ohio Shale	160,000	0-4.5	0.4-1.3	225-248[3]	1980 & 1992 NPC estimates	14.5-27.5	1980 & 1992 NPC estimates	90.7
Michigan	MI, IN, OH	Antrim Shale	122,000	1-20	0.4-0.6	35-76	1980 & 1992 NPC estimates	11.0-18.9	1992 NPC & 1995 USGS estimates	40.6
Illinois	Il, IN, KY	New Albany Shale	53,000	1-25	0.4-1.0	86-160	1980 & 1992 NPC estimates	1.9-19.2	1992 NPC & 1995 USGS estimates	NA
Fort Worth	TX	Barnett Shale	4,200[3]	4.5	1.0-1.3	NA	NA	3.4-10.0	Schmoker, 1996 Kuuskraa, 1998	NA
San Juan	CO, NM	Lewis Shale	1,100[3]	0.45-2.50	1.60-1.88	96.8	1997 Burlington Resources estimate	NA	NA	NA

1. GRIa, 2000; and GRI Baseline Projection of U.S. Energy Supply and Demand to 2015 (GRI 00/0002.2)
2. Black shale only 3. Play area only

Table 3: *Key properties for producing U.S. shale gas basins.*

Property	Barnett	Ohio	Antrim	New Albany	Lewis
Depth, ft	6,500-8,500	2,000-5,000	600-2,200	500-2,000	3,000-6,000
Gross Thickness, ft	200-300	300-1,000	160	180	500-1,900
Net Thickness, ft	50-100	30-100	70-120	50-100	200-300
Bottomhole Temp °F	200	100	75	80-105	130-170
TOC, %	4.5	0.0-4.7	1-20	1-25	0.45-2.5
$\%R_o$	1.0-1.3	0.4-1.3	0.4-0.6	0.4-1.0	1.60-1.88
Total Porosity, %	4-5	4.7	9	10-14	3.0-5.5
Gas Filled Porosity, %	2.5	2.0	4	5	1-3.5
Water Filled Porosity %	1.9	2.5-3.0	4	4-8	1-2
K_h md-ft	0.01-2	0.15-50	1-5,000	NA	6-400
Gas Content, scf/ton	300-350	60-100	40-100	40-80	15-45
Adsorbed Gas, %	20	50	70	40-60	60-85
Reservoir Pressure, psi	3,000-4,000	500-2,000	400	300-600	1,000-1,500
Pressure Gradient, psi/ft	0.43-0.44	0.15-0.40	0.35	0.43	0.20-0.25
Well Costs, $1,000	450-600	200-300	180-250	125-150	250-300
Completion Costs, $1,000	100-150	25-50	25-50	25	100-300
Water Production, Bwpd	0	0	5-500	5-500	0
Gas Production, Mcf/ton	100-1,000	30-500	40-500	10-50	100-200
Well Spacing, Acres	80-160	40-160	40-160	80	80-320
Recovery Factors, %	8-15	10-20	20-60	10-20	5-15
Gas-In-Place, Bcf/Section	30-40	5-10	6-15	7-10	8-50
Reserves, MMcf	500-1,500	150-600	200-1,200	150-600	600-2,000
Historic Production Area Basis for Data	Wise Co., Texas	Pike Co., Kentucky	Otsego Co., Missouri	Harrison Co., Indiana	San Juan & Rio Arriba Co., New Mexico

- Upper Fernie Group units – including the Grey Beds, Green Beds, and Passage Beds – have relatively low total organic carbon contents and a mainly siltstone to sandstone facies component. These units are considered to have low shale gas potential but could act as permeability pathways for production if linked through natural fracture networks to underlying Fernie shale source rocks.
- The stratigraphy and gas shale attributes of the Fernie Group are understudied and, as such, this interval requires more geological, geochemical and structural analysis before its gas shale potential is comprehended.

Doig, Doig Phosphate and Montney:

- Shale/sandstone ratios increase to the west.
- Shore-face sands and coquinas to the east are generally wet; therefore, there are few candidates in this area because a fracture in the shales would break out into the wet sands, producing water but little, if any, gas.
- The best candidates in the Montney Formation are wells with thick shales to complement gas-bearing turbidite sands. The turbidites act as permeability pipelines, and the shales act as long-term gas sources.
- It is also important to explore in areas naturally fractured because of tectonic stresses, such as faulting and graben formation, as well as drape features over reef build-ups.
- The Doig Phosphate is an excellent hydrocarbon source-rock; therefore, the best candidate would be a thick phosphate unit in a naturally fractured area.
- In the Upper Doig, the best potential is in areas with shales with gas-bearing shoreface sands in naturally fractured areas.
- It is important to look for areas with high total organic carbon and hydrogen index values, where the maximum temperature is between 787°F and 967°F, especially where there is multizone potential.
- Avoid areas with wet zones, especially shoreface Montney sands along the east side of the Triassic Basin, and porous Paleozoic (e.g., Belloy) wet reservoirs. Fracturing in shales easily break through into these porous wet zones.

Exshaw and Bakken :

- The Exshaw and Bakken shales form a widespread continuum of highly organic-rich rocks across the WCSB and Williston Basins. However, at this time these shale formations are not considered large-potential shale gas targets because of the limited thickness of the unit and the source rock properties, and source rock properties and thermal maturity.
- One important characteristic common to the various shale gas reservoirs being produced in the U.S. is the significant thickness of the producing shale units. All exhibit hundreds of feet of net reservoir thickness. The maximum thickness of the Exshaw and lower Bakken shales are 59ft and 65.5ft, respectively, with the majority of these shales less than 30ft to 45ft thick. Because of the thin nature of these shales, the shale gas reservoir potential is considered to be low.
- Numerous authors have shown the Exshaw and Bakken shales are proven oil, but not gas, source rocks in the WCSB and Williston Basin. However, the thermal maturity of the Bakken shales is below the oil generation window in all but the deep portion of the Williston Basin in North Dakota. The Exshaw shales are also below the oil generation window across much of Alberta. Where the shales are mature enough to have produced oil, they are at considerable depths (often greater than 8,200ft for the Exshaw shales). Because of these depths, the cost of drilling to these targets likely will be too high to make the Exshaw shales serious shale gas drilling targets. Overall, the shale gas potential of the Exshaw and Bakken Formations is judged to be quite low.

Ireton and Duvernay:

- Both formations are widespread from central to northern Alberta.
- The Ireton is not considered to be a significant gas shale target.
- The Duvernay Formation is a proven organic

great potential as a gas shale.

rich source rock for oils in the WCSB and has great potential as a gas shale.

- The Duvernay Formation is up to 330ft thick.
- The Duvernay Formation is immature to mature in the East Shale Basin and mature to post-mature in the West Shale Basin.
- Fracturing of the Duvernay Formation has been noted.
- Because the Ireton and Duvernay exceed 3,000ft over much of the study area, economics would dictate that any stand-alone exploration program for shale gas in either formation should concentrate on the eastern margin of the East Shale Basin. Because maturity decreases from west to east, it is probable that oil, instead of gas, will be encountered at these shallower depths.

General conclusions and recommendations

Because this study is a preliminary investigation of selected shale units in the WCSB, it should not be viewed as final or definitive. Further in-depth analysis is needed to delineate areas of maximum potential for thermogenic and biogenic shale gas production from this vast basin.

In addition, because of corporate restructuring, GTI found it necessary to reduce the time and resources available to complete the study. Nonetheless, it is clear that the WCSB contains large resource potential for shale gas.

A logical progression for further work would include:

Structural analysis—Without some element of fracturing, these shales are simply source rocks. There is a need to incorporate as much information as possible in the analysis, including seismic data, aeromagnetic and gravity anomalies, known faulting, basement controls and favorable geological elements such as pinnacle reef structures. Map thickness and lithology variations of the formations also should be noted. Anomalies may define lineament block outlines.

Integration with corporate exploration focus—If a recompletion or incremental production strategy is planned, the area of interest will need to fit with other focus areas so access to existing or planned wellbores can be obtained.

Review of previous exploration efforts—Examine existing cores for evidence of fracturing, dolomitization, fracture filling and other characteristics. Review well logs for gas shows, temperature anomalies, pressure data and production tests. Review imaging logs if available. Incorporate anecdotal information from those who have worked within these formations. Identifying zones of overpressuring may be critical.

Acquisition of geochemical data—Review existing public data, re-examine proprietary data if available, and carry out selective sampling programs where appropriate. The intent is to establish the degree of maturity and delineate zones of high total organic carbon within the formation of interest.

Determination of appropriate testing and completion strategy—Investigate various methods that have been attempted in other shale basins in the United States.

Evaluation of recompletion vs. new-drill options—With increasing depth of cover, consider exploration for shale gas within these formations as a recompletion strategy in previously drilled wellbores or as an additional pay opportunity in any planned new drill locations. ✧

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This article was excerpted from the report Shale Gas Potential of Selected Upper Cretaceous, Jurassic, Triassic, and Devonian Shale Formations in the WCSB of Western Canada: Implications for Shale Gas Production. Co-authors of the report are Basim Faraj, Harold Williams, Gary Addison, Brian McKinstry, Roland Donaleshen, Garth Sloan, James Lee, Tom Anderson, Rayleen Leal, Colin Anderson, Carolle Lafleur and Janice Ahlstrom, all with GTI E&P Services Canada.

The full report (document number GRI-02/0233) is available as a CD-ROM, which can be ordered (U.S. $65 plus shipping) by entering this document number in the Search box on the GTI Web site (www.gastechnology.org).

For more information about the study, contact Kent Perry, Executive Director, Exploration & Production Research, GTI. Tel: (847) 768-0961; E-mail: kent.perry@gastechnology.org

Large-Scale Sulfur Recovery

By Dennis Leppin, P.E.,
Gas Technology Institute

Recovery methods become more critical as gas production encounters more sulfur.

This article reviews the most common and cost-effective treatment systems used to remove substantial amounts of hydrogen sulfide (H_2S) and recover sulfur (S) from raw natural gas. Gas producers need to be familiar with these systems because future gas production is likely to encounter at least as much – and probably more – H_2S contamination as is found in today's raw natural gas.

Roughly 25% of the natural gas brought into production from new sources requires some degree of treatment to remove H_2S and recover S. Raw natural gas also often is contaminated with impurities, such as carbon dioxide (CO_2) and nitrogen. Carbon dioxide and H_2S are collectively referred to as acid gases, and they must be removed before natural gas can be delivered to the pipeline or customers.

Typically, the S specification in the product sales gas or pipeline natural gas is one-fourth grain per 100 scf of H_2S (about 4 ppm by volume). Amounts of other S species can vary, but total limits are typically 50 ppm to 100 ppm. The limit for CO_2 is typically 1% or 2%. These specifications are equivalent in value to total S removal.

However, the S in the removed tailgas does not have to be completely recovered. Table 1 gives indicative S recovery requirements, which do not exceed 99.8%. Local regulations may impose higher recovery requirements.

The need for cost-effective, large-scale sulfur removal

Previous articles in ***GasTIPS*** have addressed small-scale H_2S removal, such as scavenger processes, and mid-range processes, such as the CrystaSulf® process, that are generally applicable for removal of up to 20 tons per day (TPD) of S.

Large-scale natural gas production will have correspondingly large S recovery requirements, exceeding these limits. For example, 100 MMscf/d of natural gas containing 1% of H_2S would require the removal of about 42 TPD of S. The Claus-plus-Tailgas approach discussed here is the more economical choice for S above 20 TPD.

Various solvent processes are available to remove or strip acid gases from raw natural gas, relying on the solubility of these components in a physical solvent or their acidic properties to react with aqueous solutions of weak bases such as amines. By heat (for amines) or pressure reduction (for physical solvents), the solvent is regenerated and reused in the stripping or absorption step. If the gas stripped from the solvent contains H_2S, it must be processed further because environmental regulations and safety considerations would rule against its release directly to the atmosphere.

The S recovery step treats the acid gas removed from the solvent. The traditional approach has been to send these gases to a system using the modified Claus process, where elemental S is formed. The remaining gases from the Claus process are referred to as tailgases. Because the Claus process can remove about 97% of the S from the H_2S fed to the process, tailgas treatment is required to remove the remainder. The investment in the tailgas process is of the same order of magnitude as the Claus process, despite the smaller amount of H_2S removed in the latter unit.

Table 1. *This table shows U.S. regulatory guidelines for natural gas processing.*

	Sulfur Feed Rate, Long Tons per Day				
H_2S Content of Acid Gas, Percent	<2	2 to 5	5+ to 15	15+ to 300	>300
100	Unregulated	79.0	95.3-96.4	96.4-99.3	99.3-99.8
80	Unregulated	79.0	95.0-96.1	96.1-99.0	99.0-99.8
70	Unregulated	79.0	94.9-95.9	95.9-98.9	98.9-99.8
50	Unregulated	79.0	94.5-95.5	95.5-98.5	99.4-99.8
<50	Unregulated	79.0	94.5-95.5	95.5-97.9	97.9
20	Unregulated	79.0	93.4-93.5	93.5	93.5
<20	Unregulated	79.0	93.4-93.5	93.5	93.5
10	Unregulated	79.0	92.6-93.5	93.5	93.5
<10	Unregulated	79.0	79.0	79.0	79.0

In the past, the recovered elemental S had considerable value and was sold in the commercial marketplace. However, as the hydrocarbon extraction industry recovers more S from oil sands, sour crude and sub-quality natural gas, the supply of S far exceeds the demand. This has driven prices down to levels that, in some cases, will not support transportation of the S to market – such as from natural gas production in Alberta, Canada. There was some improvement in the supply/demand balance recently, with resultant higher prices, but a return to a chronic oversupply is widely anticipated.

This economic situation has led to S "blocking" – creation of large, managed S piles – and a trend toward reinjection of acid gas into suitable underground formations. Many such reinjection instances exist in Canada, with several in the United States as well.

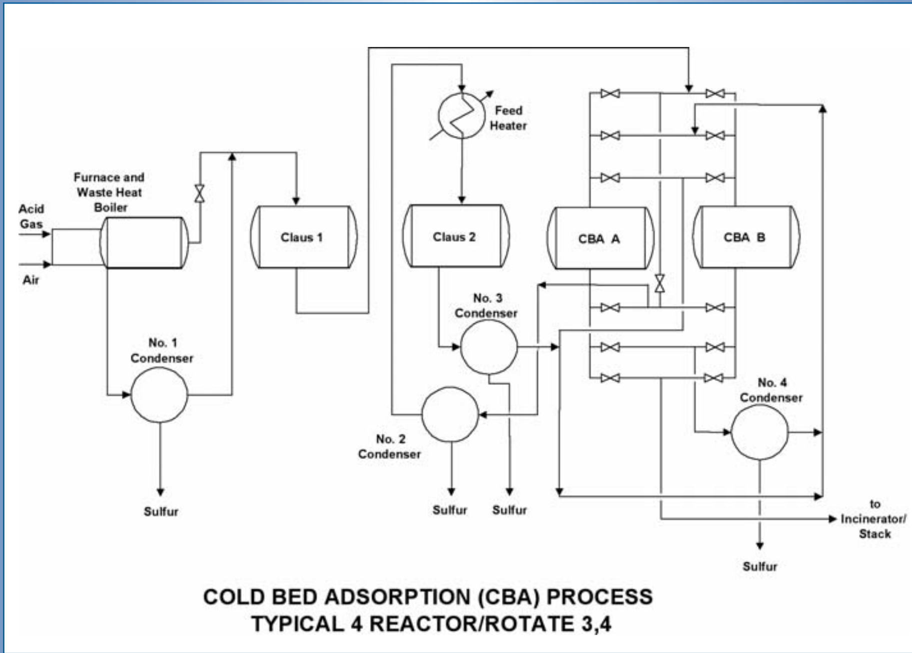

Figure 1. *This is a schematic of a modified Claus process with sub-dewpoint modification.*

Future natural gas production likely will encounter at least as much S contamination (in the form of H_2S) as present production, and probably more. It is necessary, therefore, for producers to have a certain degree of familiarity with the processes and options available for managing this contaminant. There is a pressing need for research to develop more efficient and inexpensive processes for removing and recovering S to keep its rise through natural gas production costs to a minimum. Expensive processes for S removal and recovery add to the pressures created by increased finding costs and the costs of compliance with ever-tighter environmental regulations.

The modified Claus process

The basic modified Claus process is shown in the left side of Figure 1. Low-pressure acid gas from the amine plant or physical solvent process regenerator (stripper) is mixed with air in a burner. The gas is directed into a refractory-lined furnace chamber. One-third of the H_2S in the gas is burned to sulfur oxide (SO_2), and this reacts with the H_2S to form S in accordance with the following reaction:

$$2H_2S + SO_2 \longleftrightarrow 3/n\ S_n + 2H_2O$$

The reaction indicates the ratio of H_2S to SO_2 should be about 2; otherwise, excess reactants will need to be removed. This is an equilibrium reaction that approaches completion at low temperatures and when the reactant concentrations are low, like with the removal of reactants in multiple stages. Pressure affects the reaction to S favorably, but the available acid gas is always at low pressure and the reaction is invariably carried out at a minimum pressure to allow gas flow through the system. The S is removed by cooling the gas and condensing out the S as liquid. About 65% to 70% of the S is removed immediately after this furnace/reactor step.

After this S removal step, the gas is reheated to a temperature high enough so the reaction can continue over a catalyst based on alumina. Because of thermodynamic limitations, two or three such steps (two are shown in Figure 1) with intermediate S removal and reheats are needed to approach the maximum possible H_2S-to-S conversion of about 97%.

The equipment is large and requires complex airflow controls to achieve the proper air-to-fuel ratio. In addition, numerous complications occur if there are heavy hydrocarbons in the feed and other forms of S, such as carbon disulfide, mercaptans or carbonyl sulfide in the feed. These compounds may not be removed in the process and can contribute to the net emission of S compounds from the process.

Many improvements to this basic process have been developed, such as special catalysts to assist in converting non-H_2S sulfur compounds and various schemes to operate the catalysts with S deposited on the surface (dry-bed sub-dewpoint processes as shown on the right side of Figure 1). This improves yields and lowers net S losses to the tailgas but requires periodic or cyclic operation to

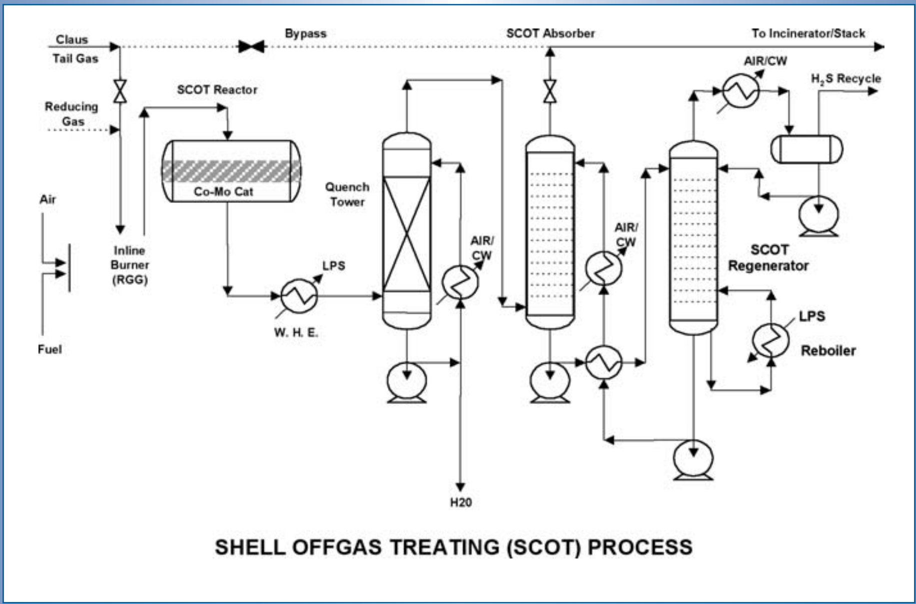

Figure 2. *Shell Global Solutions has developed the SCOT Process shown in this flow diagram.*

remove S from the beds, special switching valves and extra beds to enable continuous operations, all with attendant costs. Such approaches can achieve recoveries in excess of 99% and, in some situations, can meet applicable regulations without an additional tailgas plant.

If an existing process is limited by sulfur capacity, oxygen can be fed instead of air to coax additional throughput from the system.

There are numerous process schemes to handle the tailgas leaving the Claus process. The dominant scheme is one offered by Shell Global Solutions, the SCOT process (Figure 2.)

In this approach, the tailgas is heated to 482°F to 572°F and set to react with hydrogen or a reducing gas over a cobalt molybdate catalyst, which converts all the S compounds to H_2S. The offgas from this step is cooled in a direct water quench, which cools the gas to 100°F. In the final step, H_2S is absorbed in a specially formulated amine that selectively absorbs H_2S (instead of CO_2). The absorbed H_2S is stripped and sent to the front end of the Claus furnace. In this way, the net emissions of H_2S or SO_2 are kept low, and overall S recovery in excess of 99.9% can be achieved. The inert gases and the relatively small amount of S compounds not absorbed in the SCOT absorber are sent to an incinerator and then emitted to the atmosphere. Usually, less than 100 ppm of SO_2 will be emitted from the incinerator stack. At some point, the Claus and SCOT catalysts must be replaced. Typically, Claus catalysts last 3 years, and SCOT catalysts last 5 years.

Other approaches oxidize the remaining H_2S with air directly to elemental S, convert all the S compounds to H_2S and then oxidize to elemental S, convert the H_2S to SO_2 and recycle the SO_2.

Liquid redox processes, such as LO-CAT II, can be used in tailgas service provided the total S recovery duty considering only the tailgas is in the economic range for the process, less than about 20 TPD.

S. Lynn et al. has described a developmental approach – the University of California Sulfur Removal Process (UCSRP) – radically different from the modified Claus-plus-Tailgas approach.

The CrystaSulf process also can be employed as a tailgas process, with the same caveat on total S recovery stated for LO-CAT II.

Future gas processing issues

The total cost of producing natural gas includes finding costs, drilling costs, transportation and gas-treating costs. As new supplies are brought onstream, a significant fraction – on the order of 25% – will require some degree of treatment to remove H_2S and recover S. This can involve large, complex facilities, so development of cheaper, simpler and safer processes is critical to maintaining the overall gas supply value chain.

For offshore sour gas operations, the handling of sour gases on platforms presents an additional challenge that, for the most part, has not been squarely addressed by the industry yet. This raises a new set of process issues, costs and hazards. The Gas Technology Institute is developing a gas/liquid membrane contactor technology that might make more feasible the separation of H_2S and CO_2 from natural gas on platforms, but it will take several years of development before it can be used in that application. ✧

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New High-Power Fiber Laser Enables Cutting-Edge Research

By Brian C. Gahan,
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According to many in the laser industry, fiber lasers are a serious alternative to solid-state and carbon dioxide lasers for industrial material-processing applications. The recent commercial availability of high-power fiber lasers presented a timely opportunity for Gas Technology Institute to enhance ongoing research of laser applications for well construction and completion.

From 1997 to 1999, Gas Technology Institute (GTI – then operating as Gas Research Institute) assembled an exploratory research team to investigate fundamental research issues on a laser drilling applications concept. The GTI team, including the Colorado School of Mines and the U.S. Department of Energy (DOE), tested three military laser systems on more than 200 samples, including shale, limestone and sandstone. Lasers fired in the initial investigation included the U.S. Army mid-infrared advanced chemical laser, the U.S. Air Force chemical oxygen iodine laser and the laser hardening material experimental laboratory carbon dioxide laser (see *Lasers May Revolutionize Drilling and Completions in the 21st Century, **GasTIPS***, Winter 1998/1999, Vol. 5, No. 1, p. 11-15). The conventional wisdom regarding laser applications held by the industry at that time excluded their practical use for well construction and completion. This skepticism, however, was based on the technical limitations of rudimentary lasers from the 1960s and 1970s. Since that time, significant advances have evolved in laser power generation, efficiencies and transmission capabilities. Imagine forecasting the success of research activities based solely on state-of-the-art computer technology from 40 years ago.

GTI's initial study showed that current laser technology is more than sufficient to break, melt or vaporize any lithology encountered in the subsurface, and that the amount of energy required for spalling (melting or vaporizing) rock was significantly overestimated by previous industry sources. In addition, it was found that the energy required to remove and change the rock varies as much within lithologies as between them. Researchers did not quantify minimum power required to remove rock or factors that control power requirements.

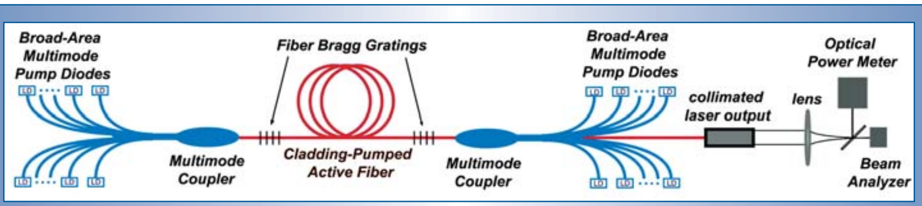

Figure 1. *In a fiber laser, a doped silica "active" fiber is excited by a diode source. Two Bragg gratings written into the fiber act like the mirrors of a normal laser cavity to generate the laser emission.*

Other observations from these experiments related to cutting ease and speed, as well as altering rock properties. It was observed that calculated penetration rates for all the rock samples, except salt, were faster than rates observed by most conventional rock-removing mechanisms. Although not performed under *in-situ* conditions, the cutting of hard rocks with close grain-to-grain contact was more easily accomplished than more porous rocks.

In addition, the thermal energy from the laser beam introduced some fundamental changes in rock properties. For example, the porosity of the rock surrounding the lased hole in a Berea sandstone sample actually increased. Also, the experiments indicated that at such high powers, there were harmful secondary effects that increased as hole depth increased. These effects included the melting and remelting of broken material, exsolving gas in the lased hole, and induced fractures, all of which reduced the energy's efficiency in rock removal and therefore the rate of mass removal.

It became clear from these experiments that through controlling the laser input parameters, rock removal and rock property alterations for various rock descriptions could be controlled. By doing so, the amount of material melted during the laser exposure could be determined, as could the minimum laser power necessary to drill rocks for oil and gas applications. From the results seen, the most powerful lasers available are able to quickly vaporize rock. However, an economic case for doing so would likely prove difficult to support.

Industrial lasers quantify results

If megawatt-sized lasers were technically capable but too costly to implement, would kilowatt-sized industrial lasers have enough punch to economically perform the same task? To find out, GTI shifted its investigation to include two lasers at the Laser Applications Laboratory at DOE's Argonne National Laboratory (ANL). These pulsed lasers were used to explore the basic scientific principles of interaction between laser and rock to determine the conditions required for an industry-supported drilling and completions concept.

For this investigation, researchers at GTI, the DOE's National Energy Technology Laboratory,

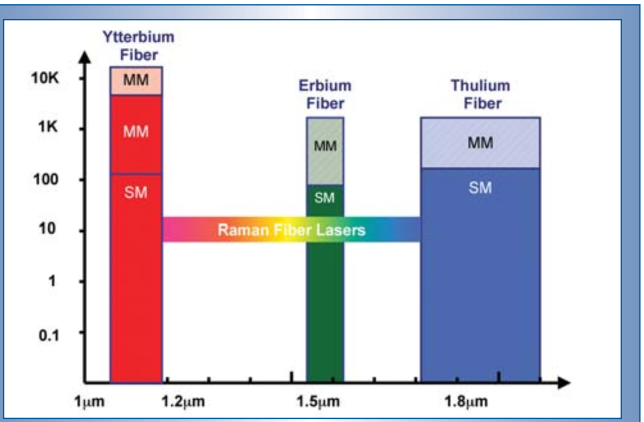

Figure 2. *This figure shows fiber laser spectral ranges. The solid areas represent output levels and shaded areas represent planned output levels. Power (in Watts) is plotted on the y-axis, and wavelength is plotted on the x-axis. SM = single mode; MM = multimode.*

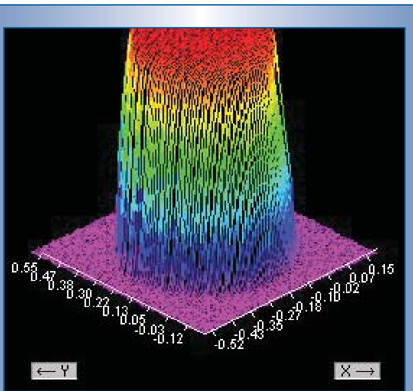

Figure 3. *This figure shows a 3-D beam profile of a fiber laser emission.*

Petroleos de Venezuela-Intevep SA, Halliburton Energy Services, the Colorado School of Mines and ANL explored some key issues:

- how much energy is needed to remove a unit volume of rock;
- does pulsing the laser increase the rate of penetration; and
- can a laser beam operate in the presence of drilling fluids, or will too much laser energy be wasted vaporizing mud rather than penetrating rock.

Although some of the work was conducted with ANL's 6-kW carbon dioxide laser, most was performed with the 1.6-kW neodymium yttrium aluminum garnet (Nd:YAG) high-power pulsed laser operating at 1.06 microns. During this phase of study, tests were carried out to measure the amount of energy required to remove material under various laser conditions. The focus was on trying to minimize the secondary effects that absorb much of the laser's power and establish an intrinsic specific energy value for each sample. Specific energy is the amount of energy needed (in kiloJoules) to remove a unit volume (1 cu cm) of rock.

To this end, laser parameters, such as duration and power, were controlled such that the lased holes' diameters were larger than the depths. This, in combination with a gas purging system designed to quickly remove exsolved gases and spalled particles, provided what the team judged to be a reasonably good measure of the specific energy for each sample.

Studies of the effects of various Nd:YAG laser parameters on the samples of shale, limestone and sandstone revealed that:

- measured specific energy increases quickly with beam exposure time, indicating the effects of energy-consuming secondary processes;
- shale samples recorded the lowest specific energy values as compared with limestone and sandstone samples;
- as laser pulse repetition rate and pulse width increase, the specific energy decreases; however, pulse width is a more dominant mechanism for reducing the specific energy than is the pulse repetition rate;
- each rock type has a set of optimal laser parameters to minimize specific energy;
- rates of heat diffusion in rocks are easily and quickly overrun by absorbed energy transfer rates from the laser beam to the rock. As absorbed energy outpaces heat diffusion, temperatures rise to the minerals' melting points and quickly increase specific energy values;
- sandstones saturated with water cut faster. More power can be applied before melting commences; and
- a laser is able to spall and melt rock through water.

(See *Laser Drilling: Understanding Laser/Rock Interaction Fundamentals*, ***GasTIPS***, Spring 2002, Vol. 8, No. 2, p. 4-8.)

The cutting edge: high-power fiber lasers

Since the time GTI and its partners explored laser application issues at ANL, significant developments were made in creating and commercializing high-power fiber lasers. The principle for the laser is similar to an amplification unit used in fiber-optics systems. The design brings with it many advantages that result in high reliability and long life. IPG Photonics (IPG), a leading global designer and manufacturer of high-performance fiber lasers and amplifiers in Oxford, Mass., had been turning up the power and made an early entrance to the market.

In a fiber laser, a doped silica "active" fiber is excited by a diode source (Figure 1). Two Bragg gratings written into the fiber generate the laser emission, resulting in an efficient, compact laser source with excellent beam quality. IPG found a way to "bundle" its ytterbium-doped fiber lasers together efficiently. It also produced systems that emit up to 6 kW of continuous-wave power at 1.08 microns through the integration of standard sub-assemblies. The number of sub-assemblies used determines the maximum power from the system. At the heart of IPG's technology are proprietary active fibers and a patented pumping technique allowing the utilization of broad-area multimode diodes rather than diode bars. This leads to a projected diode lifetime of more than 100,000 hours of operation. The diode pump energy is delivered to the active medium through multimode fibers spliced to the multiclad coil. The laser cavity is created directly in the active fiber. The laser emission leaves the fiber laser through a passive single-mode fiber, typically with a core diameter of 6 microns.

The resulting laser beam is essentially diffraction-limited and, when outfitted with an integral collimator, produces a beam that is extremely parallel. For example, a 100-W single-mode fiber laser has a full angle divergence of 0.13 milliradians at half-angle when collimated to about 0.2-in. diameter.

The maximum power from an industrial single-mode IPG fiber laser module is 200 W – higher powers are produced using multiple modules. The emissions from lasers are collected using a proprietary beam combiner, resulting in a single high-quality beam. For example, a 1-kW unit would be made up of 10 individual fiber lasers integrated into a common cabinet. Although the beam is no longer single-mode, the resulting M2 value of 7-10 is better than high-power solid-state lasers (M2 is a measure of beam quality; M2=1 for a pure Gaussian beam). The beam from a 6-kW fiber laser can be delivered using a 200-micron to 300-micron fiber. Different output beam profiles, including a near-perfect rectangular shape, can be produced.

The ytterbium fiber laser has a wall-plug efficiency of 16% to 20%. Erbium and thulium fiber lasers demonstrate lower wall-plug efficiency but are more efficient than typical YAG lasers (Figure 2). There are certain applications where these wavelengths are the best choice. Erbium lasers are being developed because of demand for a laser with the performance of Nd:YAG and eye safety better than carbon dioxide (CO_2) types.

Single-mode continuous-wave systems can be modulated to 50,000 Hz with pulse durations as short as 10 microsec. Three super-pulsed versions with pulse durations as short as 1 nsec or pulse energies up to 1 milliJoule in a 100-nanosecond (nsec) pulse and multimode continuous-wave versions from 300 W to 6 kW are available.

Figure 4. *Researchers prepare to shoot a laser beam at the small cylindrical rock sample (lower left) in the Gas Technology Institute's new laser laboratory for exploration and production applications. The IPG Photonic 5-kW ytterbium fiber laser is in the vertical cabinet in the center background. (Photo courtesy of GTI)*

Fiber laser technology offers several benefits from other industrial lasers. The footprint of a 4-kW fiber laser unit is 5.4 sq ft vs. 118 sq ft for a conventional lamp-pumped Nd:YAG, and there is no requirement for a chiller. They are essentially maintenance-free during their lifetime because there is no need to replace flashlamps or diodes. The high electrical efficiency reduces operating costs. Better beam quality (Figure 3) allows the user to produce spot diameters substantially smaller than conventional lasers, producing high fluence and/or longer working distances (1 kW can be focused to 50 microns with a 4-in. lens).

The cost for fiber laser technology, up to 1 kW output power, is below or comparable to that of lamp-pumped YAG lasers. The acquisition cost of a fiber laser greater than 1 kW is higher. However, when all factors – floor space, chillers, maintenance – are accounted for, these lasers should be more cost-effective than equivalent power rod-type Nd:YAG lasers.

The fiber laser system solves many of the application issues posed by the industry for years. Conceptually, the fiber laser represents the industry's initial candidate for well completion applications in the field, with the laser unit remaining at surface and beam energy directed downhole through an optic fiber to the target. Other laser systems may also be applicable; however, they were not considered near-term options because of technical or economic constraints.

Aside from their numerous technical advantages, it is the cost of ownership of fiber lasers that may turn out to be the key economic factor. It has been estimated that during the typical lifetime of a source, the total cost of ownership of a fiber laser is about one-third that of a similar CO_2 or solid-state device. This calculation includes the slightly higher initial purchase cost of a fiber laser compared with other lasers, and it highlights the low maintenance cost.

GTI focused on fiber lasers

Although fiber lasers were invented in 1963 and used widely at low power-levels throughout the 1980s and 1990s as optical amplifiers, their use in high-power applications was theoretical and remained years from commercial reality. IPG technology accelerated theory into reality, and GTI saw a promising opportunity to integrate high-power fiber lasers into its applications research.

In 2003, GTI formed an alliance with IPG as part of its ongoing laser applications research. At that time, GTI acquired and is operating a 5-kW IPG fiber laser (Figure 4) at its Des Plaines, Ill., research center, which is the largest available for research in the United States. The device is made from coils of ytterbium-doped multiclad fiber with an emission wavelength of 1.07 microns. Expectations are to complete proof-of-concept investigations for perforation applications with the fiber laser by this fall, to be followed by field experiments at GTI's Catoosa Test Facility in Tulsa, Okla. ✧

All graphics and photos courtesy of IPG Photonics unless otherwise noted.

Continuing Development of LNG Safety Models

By Joseph Hilyard,
Gas Technology Institute

Gas Technology Institute and the University of Arkansas are soliciting interest from organizations to participate in research to further expand the capabilities of modeling tools used to assess potential hazards associated with liquefied natural gas terminal and shipping operations.

Since 1985, Gas Technology Institute (GTI – through its predecessor company, Gas Research Institute) has supported a comprehensive research program to develop and evaluate models for assessing hazards associated with the use of liquefied natural gas (LNG). This research has been carried out at the Chemical Hazards Research Center (CHRC) of the University of Arkansas-Fayetteville (UA-F).

Several significant achievements have come from that program. An ultra-low-speed environmental wind tunnel has been constructed – the largest such test facility in the world. It is designed and instrumented in such a way as to establish free-field wind velocities as low as 0.66ft/s. Such low velocities are required to accurately simulate, at wind-tunnel scale, the dispersion of denser- or lighter-than-air gas clouds in the atmosphere. Such dispersion typically would follow the accidental release of LNG or other dense gases.

Datasets have been created for verification of dispersion predictions by two prominent modeling tools: DEGADIS (Dense Gas Dispersion) and FEM3A.

UA-F faculty members professors Jerry Havens and Tom Spicer developed the DEGADIS model – primarily for use in simulating flat-terrain and marine-environment gas releases – for the U.S. Coast Guard and the U.S. Environmental Protection Agency. It is used worldwide for hazardous chemical hazard assessment and is prescribed by the U.S. Code of Federal Regulations (49 CFR 193) for safety assessments for proposed LNG terminal sites.

The FEM3A, developed by Lawrence Livermore National Laboratory, provides the capability to analyze gas dispersion in more complex local environments and the simultaneous release of gas from multiple sources. Havens and Spicer further developed the FEM3A model for applications to LNG safety, and it has been incorporated into 49 CFR 193 as a possible alternate to DEGADIS.

Mathematical model simulations using DEGADIS and FEM3A have demonstrated agreement with wind-tunnel datasets, and research continues to verify the models for use under more complex and site-specific situations.

Topical reports describing work to date have been completed and, based on review of those reports by the U.S. Department of Transportation and the National Fire Protection Agency, DEGADIS and FEM3A are prescribed for use by 49 CFR 193 and NFPA 59A.

Objective of continuing research

GTI proposes to continue research with UA-F that will focus on developing the FEM3A dispersion model for application to scenarios involving dispersion problems with obstacle and terrain features of more realistic complexity and for very low-windspeed, stable weather conditions as required for LNG vapor dispersion applications specified in 49 CFR 193.

The success of this research will provide the FEM3A model with an advanced turbulence closure model – for describing the turbulent mixing with air of denser-than-air gases or aerosols – that will allow for more realistic description of dispersion problems with more complex obstacle and terrain features. These include houses, industrial buildings, tanks, dikes, vapor fences, significant terrain slopes, cliffs and valleys.

The resulting FEM3A model will be useful for evaluating hazard consequence

Figure 1. *A fan for producing low-speed airflow is shown in the University of Arkansas's wind tunnel.*

issues for a range of materials, including LNG and other liquefied fuels.

Most importantly, the continued updating and improvement of the model will provide evidence of its applicability to a variety of scenarios. This evidence will meet the requirement, implicit in 49 CFR 193, that the model should be subjected to experimental verification when applied to new applications significantly different from those already approved.

Such a standardized and verified model – not currently available – will be valuable for evaluating hazard consequence issues for a range of materials (including LNG and other liquefied fuels) in routine industry practice as well as consideration of the impact of terrorist actions.

Wind tunnel testing and the use of improved modeling tools eliminate the high cost and insufficient controllability inherent in larger-scale field tests, assuming that consistent agreement between wind-tunnel tests and model simulations can be achieved.

Test facilities

The CHRC experimental facilities at UA-F are unique (see *New Models Predict Consequences of LNG Releases, **GasTIPS** –* Fall 2002, Vol. 8, No. 4, p. 27-30 – for a detailed description). The purpose-built wind tunnel is the largest operating wind tunnel specifically designed to study dense gas dispersion. It is an ultra-slow-speed, boundary-layer wind tunnel capable of producing conditions that simulate normal atmospheric airflow.

Airflow from the fans (Figure 1) passes through a circular-to-rectangular transition zone before entering the working area (Figure 2). Just downstream from the transition zone is the boundary-layer-generation region. As the air flows through a honeycomb of one-half-in.-square cells, it is straightened and large-scale turbulence is removed. Then, four seamless screens placed downstream from the honeycomb further reduce turbulence, generating a uniform airflow across the cross-sectional area of the wind tunnel.

A turbulent boundary layer is induced by turbulence generators (Figure 3), positioned 11.8 in. downwind from the last screen.

A full complement of instrumentation is used to measure turbulence statistics and gas concentrations at desired locations in the wind tunnel. Instrumentation includes:

- hot-wire, pulsed-wire, Laser Doppler and Phase Doppler anemometry;
- particle-imaging velocimetry; and
- fast-response flame ionization detectors.

All instruments can be traversed in three dimensions to take measurements at specific vertical, lateral and downwind positions. ✧

Figure 2. *The working area of the low-speed wind tunnel comprises a space 7ft high, 20ft wide and 80ft long.*

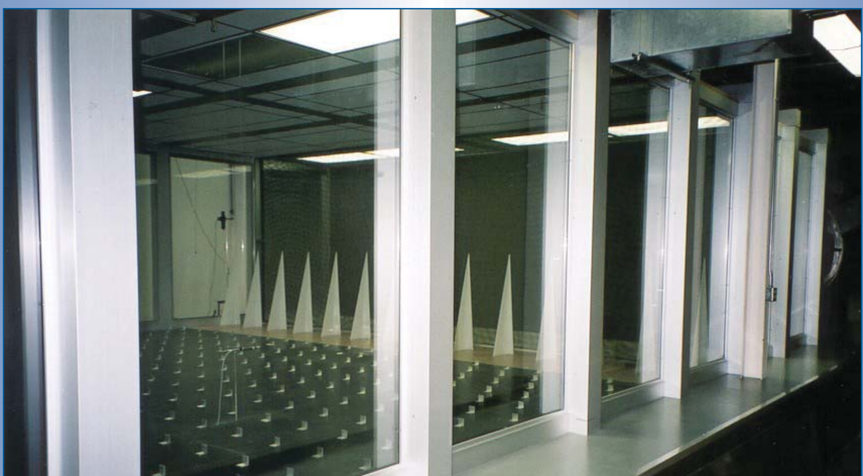

Figure 3. *Fourteen Irwin spire-shaped structures generate turbulence in the low-speed wind tunnel.*

Contact Information

For more information about this planned research or licensing the models, contact Dennis Leppin, GTI Associate Director, Gas Processing, at phone: (847) 768-0521, or email: dennis.leppin@gastechnology.org

All photos courtesy of University of Arkansas-Fayetteville, Chemical Hazard Research Center.

In Brief

GTI Establishes New Group

John F. Riordan, president and chief executive officer of Gas Technology Institute (GTI), has announced the establishment of a new GTI group in Birmingham, Ala., for research on various aspects of gasification.

Gasification is the controlled application of heat and pressure to convert various feedstocks into fuel-gas or chemicals. Interest is growing in this process as a way to expand supplies of gaseous fuels and produce valuable chemicals from coal, wastes and renewable resources such as biomass.

For example, the federal energy bill being debated would authorize at least $1 billion under the Clean Coal Initiative for coal-based gasification projects. These could include combined-cycle or fuel cell power generation units coupled with gasification and hybrid gasification/combustion systems.

Riordan noted an advanced test facility being built at GTI's Des Plaines, Ill., campus is explicitly designed to evaluate and optimize advanced gasification and related thermo-chemical conversion processes.

Vann Bush is director of the new Process Research and Evaluation (PR&E) Group. He and his staff were formerly with the Environmental & Energy Division of Southern Research Institute (SRI), in Birmingham. GTI acquired the PR&E Group when SRI made a strategic decision to phase out that part of its business.

The PR&E Group has extensive expertise in process engineering, measuring and monitoring emissions, and combustion-emissions control. Bush also noted the group's experience with technologies for cofiring biomass with coal in work done at the pilot scale (with Southern Co.) and full scale (with Alabama Power Co.). This work included development of an economic model for biomass production in the Southeast.

A major PR&E Group project launched in November concerns the gasification of biomass to produce a syngas suitable for high-efficiency power generation in the forest-products industry.

More specifically, the group is designing and building a transportable "slipstream" unit for analyzing the syngas produced by operating gasifiers or gasification test facilities and for evaluating the performance of various syngas cleanup processes.

Ten organizations (including GTI) are participating in the biomass gasification project. The project sponsor – the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy – is providing $3.4 million in funding. GTI, EPRI, Southern Co., BE&K Engineering, the University of Alabama at Birmingham and VTT (Technical Research Centre of Finland) are providing co-funding.

SWC Seeks Proposals

The Stripper Well Consortium (SWC) recently released its 2004 request for proposals.

Proposals are due by 4 p.m. EST April 26. The SWC expects to provide about $1 million in co-funding during this round. The SWC mission is to assist stripper well operators in the development, demonstration and commercialization of technologies to improve the production performance of the nation's natural gas and petroleum stripper wells. During the past 3 years, the SWC has provided $3.3 million to co-fund 39 projects. The consortium membership stands at 63 members extending to 16 U.S. states as well as Canada and Venezuela. For more information on this funding opportunity and the consortium, please visit the SWC Web site at *www.energy.psu.edu/swc/*

New R&D Solicitation

The National Energy Technology Laboratory is planning a solicitation with a release date close to the end of January 2004. Research and development (R&D) will target deep gas imaging and diagnostics. Technological advances are needed to obtain better images of deep gas plays and more precise measurement of critical reservoir properties in deep gas plays, like at depths greater than about 15,000ft. Regionally, the solicitation is targeting the shallow water/deep gas portion of the Gulf of Mexico and deep portions of onshore basins in the United States. These basins include the Greater Green River, Wind River, Anadarko and Uinta. Stay abreast of the announcement by visiting *www.netl.doe.gov/business/solicit/* ✧

New Publications

Developing and Demonstrating the CrystaSulf Process

CrystaSulf is a new process for medium-scale sulfur recovery (0.2-25 tons of sulfur/d) from sour natural gas. This report describes:

- technical development by Gas Technology Institute (GTI) beyond the pilot scale that cut the capital and operating cost of CrystaSulf by 20% to 25%;
- studies that identified potential further enhancements for additional cost savings of 50%;
- planning for commercialization of the enhanced process; and
- development of tools to evaluate potential applications and estimate costs.

The work showed the natural gas industry needs a new medium-size sulfur recovery technology and that CrystaSulf can provide cost savings and performance benefits vs. other options.

Price: $60 plus shipping and handling.

Document number GRI-03/0088. Report on CD-ROM.

Order through the GTI Web site: *www.gastechnology.org*

Mitigation Methods for Accidental LNG Releases

This is one of a series of reports on methods for liquefied natural gas (LNG) vapor dispersion prediction. Wind tunnel releases of carbon dioxide to study dispersion of flammable vapors from an LNG spill provided additional data for the continuing validation of the FEM3A model. The experiments were 1:150 scaled physical models of the continuous, steady boil-off of LNG vapor from a 0.6-cu m/sec spill of LNG into the annular area surrounding a tank at the center of a square dike. Experiments used two dike designs believed to represent current-practice size limits for the United States. Results suggest that FEM3A modeling of such events may be useful for dike design – as well as other plant layout features – to minimize the extent of vapor dispersion hazard zones.

Price: $200 plus shipping and handling.

Document number GRI-03/0104. Report on CD-ROM.

Order through the GTI Web site: *www.gastechnology.org*

Powder River Basin Coal Gas Resource and Production Potential

This report measures and interprets a comprehensive suite of formation evaluation data to quantify reservoir properties and predict gas producibility in the Fort Union Formation coal seams of the Powder River Basin (PRB) in Wyoming and Montana. The project demonstrated a way to explain the unusual reservoir properties of low-rank coalbed gas reservoirs using careful data acquisition and analysis plans. The report presents geochemical, petrographic and well test results for a sub-bituminous coalbed gas well.

This study was important because low-rank coalbed reservoirs pose analytical challenges because of their propensity to undergo aerial oxidation and desiccation; and coal-gas reservoir data are scarce in the PRB and for low-rank coal in general.

Price: $60 plus shipping and handling.

Document number GRI-02/0232. Report on CD-ROM.

Order through the GTI Web site: *www.gastechnology.org*

Natural Gas Produced Water Management Decision Tree Model

This report summarizes produced water disposal practices and regulatory issues at a local level, presenting data on produced water management practices used in 30 selected basins in 10 states. The data can be easily accessed through a software tool called the Produced Water Management Decision Tree Model (PWM DTM), developed as part of this project.

The report provides instructions for use of the model, and the model is included on compact disc. The PWM DTM provides oil, gas and water production statistics along with Internet links to the appropriate regulatory agencies for each state considered. The PWM DTM also provides general information describing each reported PWM technology, and the pros and cons of owner-operated and commercial technology application.

Price: $75 plus shipping and handling.

Document number GRI-03/0072. Report and software on CD-ROM.

Order through the GTI Web site: *www.gastechnology.org* ✧

▶ NORTH AMERICAN PROSPECT EXPO

Feb. 5-6, Houston

For more information, visit *www.landman.org*

▶ NATURAL GAS TECHNOLOGIES II: INGENUITY AND INNOVATION

Feb. 8-11, Phoenix

This is the second Gas Technology Institute-sponsored conference and exhibition designed to showcase new and developing natural gas technologies from across the industry. To be held at the Pointe South Mountain Resort, the conference is co-sponsored by the U.S. Department of Energy's National Energy Technology Laboratory. Details at *www.gastechnology.org*

▶ CAMBRIDGE ENERGY RESEARCH ASSOCIATES

Feb. 9-12, Houston

For more information, visit *www.cera.com*

▶ SOCIETY OF PETROLEUM ENGINEERS INTERNATIONAL SYMPOSIUM AND EXHIBITION ON FORMATION DAMAGE CONTROL

Feb. 18-20, Lafayette, La.

For more information, call (972) 952-9393, e-mail *spedal@spe.org* or visit *www.SPE.org*

▶ SOCIETY OF PETROLEUM ENGINEERS/INTERNATIONAL ASSOCIATION OF DRILLING CONTRACTORS DRILLING CONFERENCE

March 2-4, Dallas

For more information, call (972)952-9393, e-mail *spedal@spe.org* or visit *www.SPE.org*

▶ 14TH INTERNATIONAL CONFERENCE & EXHIBITION ON LIQUEFIED NATURAL GAS

March 21-24, Doha, Qatar

This triennial conference is sponsored by the Gas Technology Institute, the International Gas Union and the International Institute of Refrigeration, with additional sponsorship support from numerous large corporations and organizations involved in the liquefied natural gas industry. Details at *www.lng14.com.qa*

▶ ZIFF GAS STRATEGIES CONFERENCE

April 19-20, Houston

For more information, visit *www.ziffenergy.com*

▶ AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS ANNUAL MEETING

April 19-21, Dallas

For more information, visit *www.aapg.org*

▶ OFFSHORE TECHNOLOGY CONFERENCE

May 3-6, Houston

For more information, call (972) 952-9393, e-mail *spedal@spe.org* or visit *www.SPE.org*

▶ INTERNATIONAL GAS RESEARCH CONFERENCE (IGRC) 2004

Nov. 1-4, Vancouver, B.C., Canada

Held every 3 years, IGRC is recognized worldwide as the major forum devoted to the exchange of the most recent natural gas research, development and demonstration results. This will mark the ninth presentation of the IGRC. Details at *www.igrc2004.org*

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