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Commentary

Another Addition to the DOE/GTI Best Seller List

One of the articles is this issue of *GasTIPS* highlights a new publication titled *Geologic Play Book of Trenton–Black River Exploration in the Appalachian Basin*, a detailed report that incorporates and integrates regional geologic, geochemical and geophysical data to characterize two plays across the eastern U.S. basin. This publication is the result of a collaborative effort among the University of West Virginia, the U.S. Department of Energy's (DOE) National Energy Technology Laboratory and a consortium of 17 natural gas exploration companies that contributed to the cost of collecting and analyzing this information through a 2-year membership fee. All expectations are that this play book will become a valuable guide for exploration and production (E&P) companies, leading to more rapid and cost-effective development of the natural gas to be found in these important plays.

It is worth noting that this new play book is the most recent in a long line of similar publications extending back nearly 30 years, the genesis of which can be found in collaborative efforts sparked by the DOE and/or Gas Technology Institute – GTI (and its predecessor, Gas Research Institute). All of these publications had three things in common: the information in them was compiled and analyzed with the financial support of DOE and/or GTI; the information would not likely have been collected and published independently, or if it had been, would not have reached as wide an audience; and the information served as a catalyst toward the development of natural gas resources that otherwise would likely have remained underdeveloped for a longer period of time.

Just a few selected examples of these past best sellers include:

- seven reports published by the DOE's Morgantown Energy Technology Center (METC, a predecessor of NETL) between 1979 and 1981 that compiled and mapped information on the characteristics of Devonian shales in individual states across the Michigan, Illinois and Appalachian basins;
- three reports, published by METC between 1983 and 1985 that characterized the volume and distribution of technically recoverable natural gas in three important Appalachian states (Ohio, West Virginia and Kentucky);
- a series of seminal reports published by GRI between 1986 and 1992 that provided geologic assessments of natural gas from coal seams in six important coal basins (Black Warrior, Piceance, San Juan, Northern Appalachian, Central Appalachian and Raton); and
- five gas reservoir atlases, a collaborative effort of GRI, DOE, the Bureau of Economic Geology at the University of Texas, West Virginia University and others that were published from 1991 to 1997 and focused on major gas reservoirs of Texas, Central and Eastern Gulf Coast, Mid-continent, the Rocky Mountains and the Appalachian Basin.

These publications and others like them served an important purpose, focusing attention on natural gas resources that had not been seen as economically attractive targets. It is hard to say exactly how many wells were drilled or cubic feet were produced as a result of these publications being made available, but it is safe to assume they made it easier for geologists and engineers to recognize the potential of these resources and develop the prospects and plans that have made unconventional gas conventional. Gas produced from Devonian shale, coal seams and tight sands – what was a negligible contribution in 1975 – today makes up more than 30% of the nation's gas supply.

Information products from the NETL and GTI like the new Trenton-Black River play book (see outcrop photo from play book) have helped exploration and production technologists find and produce unconventional gas resources for more than two decades.

While many of the specific technologies advanced by the DOE and the GTI in laboratories and at demonstration sites during the past three decades have made important contributions to the domestic supply of natural gas, the value of this relatively "humdrum" collecting, organizing, analyzing, packaging and disseminating of data useful to E&P technologists should not be underestimated.

We hope you find this issue of *GasTIPS* informative. ✧

The Editors

Gas Hydrate Exploration and Production: Dispelling the Myths

By Arthur H. Johnson,
Hydrate Energy International;
and Michael A. Smith,
U.S. Minerals Management Service

As gas supplies tighten around the world, gas hydrate is being considered as a potentially enormous natural source by a growing number of energy companies and national governments.

Results from scientific drilling consortia such as the Ocean Drilling Program (ODP) and more recently the Integrated Ocean Drilling Program (IODP) have yielded considerable knowledge about the occurrence of gas hydrate in sediments. This knowledge will be critical for the successful commercial development of gas hydrate resources. Many old, erroneous concepts are deeply entrenched within the exploration and production community. Successful development of natural gas from hydrates will require an accurate understanding of the nature of gas hydrate formation and occurrences as well as the relationship of gas hydrates to their host sediments, such as a petroleum systems approach. Through the integration of information gained during the past 5 years, production of natural gas from hydrate should be viable in the near term – within the life of recent deepwater leases.

Natural gas hydrate is a solid, crystalline material that forms when gases, such as methane, combine with water under conditions of relatively high pressure and low temperature. The hydrate structure consists of an open latticework of water molecules that is stabilized by the gas molecules residing within regularly located voids or "cages." A single cubic foot of gas hydrate yields about 164 cu ft of gas at atmospheric pressure along with about 0.8 cu ft of water.

The physical conditions under which gas hydrate is stable (Figure 1) have long been understood for pipelines, and the flow assurance aspects of gas hydrate have been studied for decades. However, these conditions also exist in sediments along continental margins throughout the world where water depths are greater than about 1,600ft and in sediments below permafrost in Polar Regions. Gas hydrate may occur in these locations at appropriate pressure and temperature conditions within a zone of hydrate stability that extends into the sediments to depths of up to many hundreds of feet. The base of the hydrate stability zone is primarily determined by the geothermal gradient, as the increasing temperature of the deeper sediments crosses the hydrate phase boundary. The thickness of the hydrate stability zone varies with factors including temperature, pressure, gas composition and salinity, and increases with greater water depths.

As the pressure and temperature conditions for hydrate stability occur along continental margins throughout the world, the potential for large accumulations of commercial gas hydrate deposits would appear to be enormous. Other factors, however, are also required. First among these is an adequate flux of methane (or other hydrocarbon gases) into the sediment. The gas may be biogenic or thermogenic, but with either source, there must be a mechanism for migration into the hydrate stability zone. Sulfate in sediments fluids can react with methane, and in locations with an insufficient methane flux, commercially viable gas hydrate deposits will not be present. The second factor is lithology. In most locations worldwide, the sediments within the hydrate stability zone are predominantly shales, and it comprises 3% to 5% of the sediment volume where hydrate is present. In contrast, sands within the hydrate stability zone typically have high hydrate saturations within the pore space of the sediment, exceeding 80% saturation in some locations.

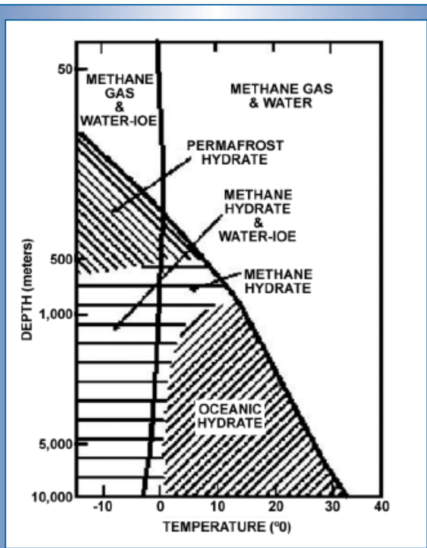

Figure 1. The above graphic is a phase diagram for methane hydrate, with permafrost and oceanic methane hydrate P-T fields delineated.

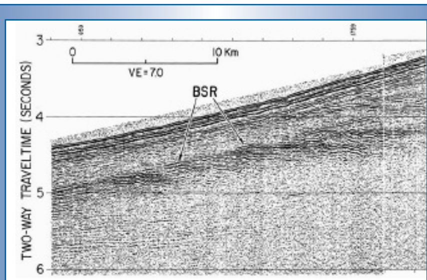

Figure 2. A seismic profile on the North Carolina continental rise illustrating a 'classic' Bottom Simulating Reflector.

During the past 20 years published literature on gas hydrates has debated the total volume of gas hydrate in the world, and significantly large numbers are typically cited. From an industry perspective, however, that discussion misses the point. What matters is the volume of gas that is concentrated in sediments that can be commercially recoverable. The vast amounts of hydrate dispersed in deepwater shales have little relevance to resource development.

Exploration for commercial gas hydrate resources must include assessments of the pressure/temperature conditions of a basin; hydrocarbon source, timing and migration; and sediment distribution. Many of the world's basins have the necessary components for commercial gas hydrate accumulations. One of the most promising is the deepwater Gulf of Mexico where prospect economics are enhanced by the presence of existing infrastructure.

The domestic oil and gas industry has largely avoided serious consideration of commercial gas hydrate development because of valid economic considerations based on early investigations. New information about hydrate formation and occurrence that has emerged in recent years has not yet been widely incorporated into industry planning. As a result, there are many outdated concepts (myths) about the resource potential of gas hydrate that need to be dispelled if the remaining challenges of gas hydrate development are to be addressed and overcome.

Myth No. 1: A commercial gas hydrate deposit is always associated with a seismic 'Bottom Simulating Reflector'

The base of the hydrate stability zone may be identified on seismic data in some locations by a strong reflection with negative amplitude that results from the impedance contrast between hydrate-bearing sediments above the phase boundary and free gas-bearing sediments below (Figure 2). During the 1980s and 1990s, this seismic event, termed a "Bottom Simulating Reflector" (BSR) because it was observed paralleling seafloor topography and cutting across stratal boundaries in dipping sediments, was the primary means of identifying areas of interest for hydrate investigations. Cores recovered by Ocean Drilling Program and Integrated Ocean Drilling Program expeditions confirmed the presence of gas hydrate in sediments overlying the BSR.

By the late 1990s, hydrate exploration and assessment was commonly viewed as a "BSR hunt. The most pronounced BSRs were off the Carolina coast on the Blake Outer Ridge, and that location became the focus of gas hydrate investigations for the U.S. In contrast, few BSRs were found in the Gulf of Mexico and where present they tended to be far weaker than those along the Atlantic margin. As a result, hydrate studies in the Gulf of Mexico focused primarily on seafloor hydrate mounds and near-seafloor accumulations associated with gas vents instead of the potential of deeper hydrate reservoirs.

Worldwide drilling results during the past 5 years have significantly altered these models. While hydrate is present in the sediments at the Blake Outer Ridge, the concentrations are low, 5% of the rock volume or less. In addition, the sediments in the hydrate-bearing interval are uniformly composed of 60% clay. The poor reservoir lithology, the low hydrate concentrations and the lack of infrastructure make the Blake Outer Ridge an unlikely candidate for commercial hydrate development. A well-defined, mappable BSR is also present in Keathley Canyon at one of the sites drilled in 2005 by the U.S. Department of Energy Gulf of Mexico Gas Hydrate Joint Industry Project (Figure 3). In these wells, the sediment within the hydrate stability zone was predominantly shale and low volumes of hydrate occurred well above the BSR.

Underlying the problem of using a BSR is the nature of the BSR itself. When present, a BSR indicates the existence of minute gas bubbles within the sediment beneath the phase boundary but conveys little or no information about the overlying hydrate-bearing sediments. The BSR is useful in gas hydrate assessments for delineating the base of the hydrate stability zone but is absent in many prospective basins. In some basins, strong, continuous BSRs may delineate locations with poor reservoir lithologies. Much of the gas hydrate resource in the Gulf of Mexico occurs in discrete sands contained within the zone of hydrate stability and is unrelated to the presence of a BSR. Therefore, hydrate-bearing sands may or may not be associated with a BSR, and where present, BSRs in sandy intervals often are discontinuous.

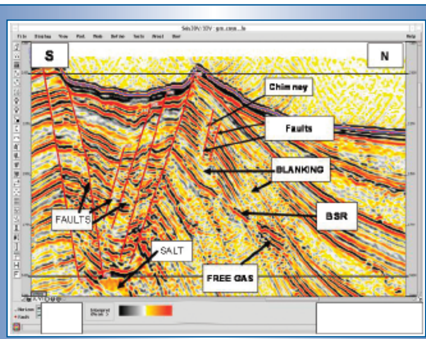

Figure 3. Three-dimensional time-migrated seismic section showing a Bottom Simulating Reflector (BSR) in the Green Canyon area. This example demonstrates the BSR has (1) high reflection amplitude, (2) reversed polarity relative to the seafloor reflection, (3) cross-cut bedding reflections and (4) is overlain by a blanking effect and underlain by free gas (from Kou and others, in press, The Leading Edge).

A successful exploration approach must consider gas hydrate reservoirs as part of the broader petroleum system and take into account sand deposition and hydrocarbon migration. Using this approach, the deepwater Gulf of Mexico has potential for commercial development of gas hydrate resources.

Myth No 2: The best gas hydrate deposits are in remote areas, far from current operations and under leasing and drilling moratoria

This myth grew out of the early emphasis on BSRs and the strong scientific focus on the Blake Outer Ridge and other remote locations. The large volume of publications focused on that location was seen to imply that the Atlantic margin was primary site for future hydrate development, and that to be prospective, other areas should have comparable BSRs. Researchers studying the Pacific coast also

Figure 4. Hydrate-derived gas is flared during the 2002 Mallik test in the Canadian Arctic.

identified gas hydrate locations offshore California and Oregon.

These areas were under moratoria. Also future leasing and drilling programs could be expected to generate a hostile response from a significant segment of the public, so a natural assumption developed for many in the oil and gas industry that gas hydrate development would not be able to proceed for decades. In addition, most of the locations on the U.S. Atlantic and Pacific margins are lacking in infrastructure, such as platforms or pipelines, severely impacting development economics.

With the information now available, commercially viable concentrations of gas hydrate are most likely to occur in basins where stratigraphy and hydrocarbon migration are optimal within the hydrate stability zone. These basins include the North Slope of Alaska and the deepwater Gulf of Mexico where less political opposition to hydrate development should be expected. In addition, large volumes of existing seismic data in these basins can be utilized to assess hydrate potential and the abundance of infrastructure significantly enhances the economics of development.

Myth No 3: Development is 20 or 30 years away and will require new methods of production

If the oil and gas industry's primary objective was to commercialize gas hydrate deposits comprised of a few percent of hydrate dispersed in shales (in 10,000ft of water), a new approach to development would be required, and a 30-year timeframe might be overly optimistic. However, the production of gas from hydrate-bearing sands will mainly entail the adaptation of existing industry technology.

In the simplest case, where a hydrate-bearing sand extends down dip across the phase boundary and includes free gas, simply producing the gas may lower reservoir pressures so hydrates dissociate (revert to gas and water), feeding more gas into the reservoir. This production approach involves little new technology. Other production scenarios involve heating or other forms of stimulation, which will yield higher production rates but increase operating expense. As with conventional gas reservoirs, hydrate-bearing reservoirs will involve a range of drive mechanisms, and the reservoir engineering aspects need additional study.

In 2002, an international consortium achieved a successful flow test from hydrate-bearing sands at the Mallik structure in the Canadian Arctic (Figure 4). While the rates of production were deliberately kept low, the test validated the producibility of natural gas from hydrate.

Because of increasing demand for natural gas, gas hydrate development programs are being undertaken in several nations, including the United States. The most ambitious programs are those of India and Japan, with India planning commercial production of gas from hydrate before the end of this decade. Successful development there will most likely accelerate development programs worldwide.

Myth No. 4: Hydrate resources in the Gulf of Mexico have no net present value so they can be ignored in lease sales

In 1998, the Solicitor General of the U.S. Department of the Interior determined that gas hydrate and associated free gas are included in the potential resources of deepwater federal oil and gas leases. The U.S. Minerals Management Service recently completed a new assessment of technically recoverable gas hydrate reserves for the Gulf of Mexico and other offshore U.S. basins. This assessment used 3-D multi-channel seismic, logging-while-drilling and electric logs, and other data to define sand fairways within the zone of hydrate stability and identify exploration wells that may have encountered hydrate within this sedimentary section. The DOE Gulf of Mexico Gas Hydrate joint industry project is currently evaluating locations likely to contain hydrate-bearing sands for a second drilling leg in the spring of 2008.

Significant technical, engineering and regulatory challenges will have to be overcome to delineate and begin production from Gulf of Mexico gas hydrate deposits. Shortages and increasing price and demand for natural gas, which could intensify from storm-related or politically caused supply interruptions, will increase pressure to fast track hydrate exploration and production. Before commercial production from gas hydrate development programs in other countries appears to be imminent, the need to test production methods in the Gulf of Mexico may be unavoidable. Deepwater operators should already be considering accelerated hydrate research programs to be able to take advantage of the full value of some OCS leases.

For more information, refer to Max, M.D., Johnson, A., & Dillon, W.P. 2006. *Economic Geology of Natural Gas Hydrate.* Springer, Berlin, Dordrecht, 341pp

Additional information can also be obtained from the following Web sites:

American Association of Petroleum Geologists Energy Minerals Division Gas Hydrate Page: *emd.aapg.org/technical_areas/gas_hydrates/index.cfm*

National Energy Technology Laboratory Gas Hydrate Page: *www.netl.doe.gov/technologies/oilgas/FutureSupply/MethaneHydrates/maincontent.htm*

Hydrate Energy International Information Page: *hydrate-energy.com/gashydrates.htm*

U.S. Minerals Management Service Gas Hydrates Page: *www.mms.gov/eppd/sciences/esp/hydrates/index.htm* ✧

Consortium Produces Geologic Play Book

By Douglas G. Patchen, *National Resource Center for Coal and Energy*; and Thomas H. Mroz, *National Energy and Technology Laboratory*

A new report from the National Energy Technology Laboratory is now available as part of a continuing program to develop resource characterization data for the future development of natural gas in the United States.

The report, titled *Geologic Play Book of Trenton–Black River Exploration in the Appalachian Basin*, incorporates and integrates regional geologic, geochemical and geophysical data to characterize two plays across the eastern U.S. basin. It highlights details of the stratigraphic relationships and facies trends, structural geology and seismic interpretations, carbonate petrology, isotope and fluid inclusion analyses, natural gas geochemistry and production trends to produce an integrated stratigraphic-structural-diagenetic model for the development of hydrothermal dolomite reservoirs in the Trenton-Black River carbonate units. Predictive resource model results are also included that assess the undiscovered natural gas resources in two Trenton–Black River gas plays: a hydrothermal dolomite gas play on the western side of the basin, extending from New York and Ontario southward through Ohio into northern Kentucky; and a fractured limestone gas play on the eastern side of the basin, extending from north central Pennsylvania southward through West Virginia into eastern Kentucky. Through much of the basin, the boundary between the two plays approximates the western edge of the Rome Trough.

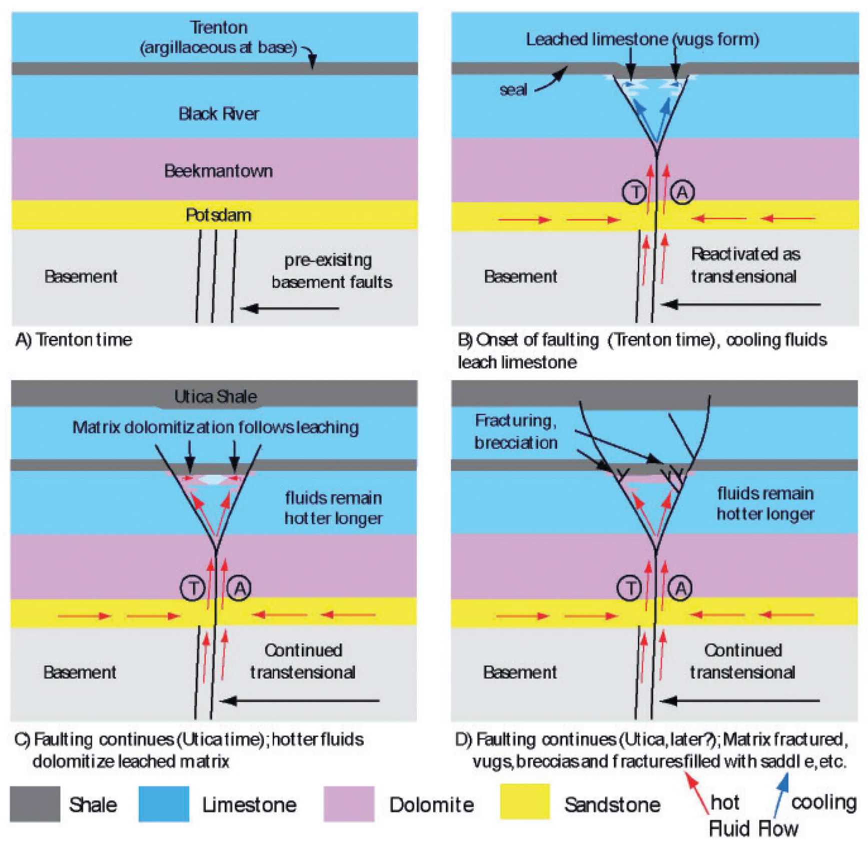

Figure 1. This schematic shows a fault-related hydrothermal alteration model for Black River Group dolomite reservoirs.

Cost-shared research result

The play book is the result of a contract awarded to the West Virginia University Research Corp. (Research Corp.) by the U.S. Department of Energy through the National Energy Technology Laboratory (NETL). The Research Corp. assigned the contract to the Appalachian Oil and Natural Gas Research Consortium (AONGRC), a program at the National Research Center for Coal and Energy at West Virginia University.

The Research Corp., working with the AONGRC, created an industry-government-academic partnership – the Trenton–Black River Appalachian Basin Exploration Consortium (the Consortium) – to co-fund and assist the research effort. Seventeen gas exploration companies joined the Consortium, contributing cost share through a 2-year membership fee.

The completed project has met its three main objectives:

- develop an integrated structural-stratigraphic-diagenetic model for the origin of Trenton–Black River hydrothermal dolomite reservoirs;
- define possible fairways within which to conduct more detailed studies leading to

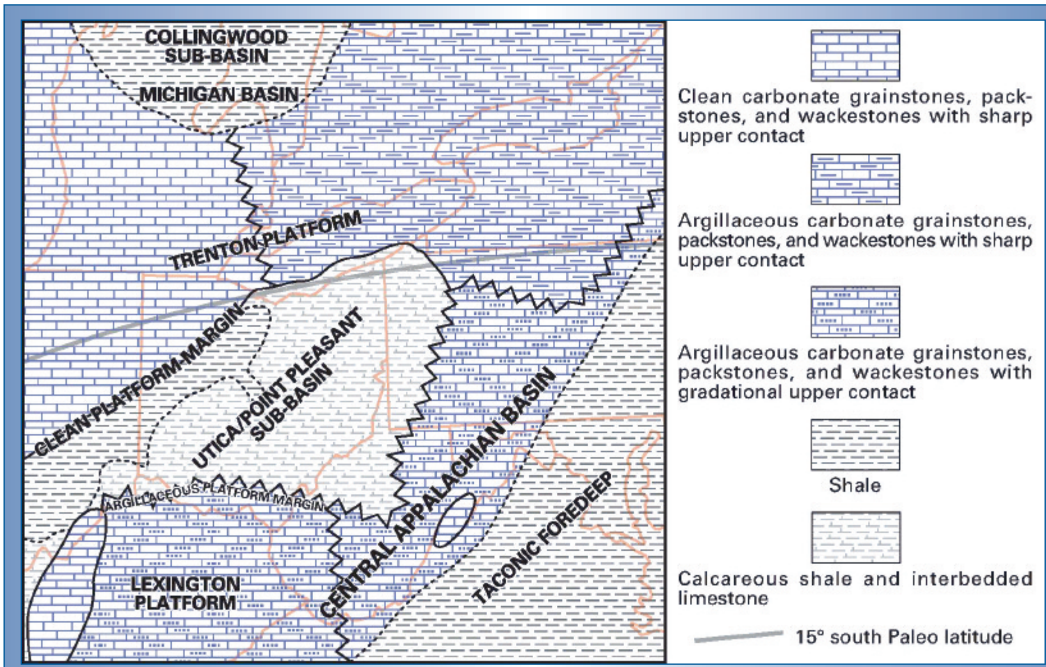

Figure 2. This facies schematic shows the fairways that help divide the Trenton-Black River gas play into two separate plays: the margin of the Trenton Platform extends from northwest Ohio eastward into northwest Pennsylvania, and the Lexington Platform extends southwestward into West Virginia and southern Ohio.

further development of the gas resource in these reservoirs; and

- develop an integrated, multi-faceted, resource assessment model of Trenton-Black River reservoirs in New York, Ohio, Pennsylvania, Kentucky and West Virginia.

The Consortium achieved these goals by conducting research in eight integrated task areas:

- structural and seismic analysis and mapping;
- analysis of stratigraphic relationships and isopach thickness trends;
- analysis of petrographic data and synthesis of depositional environments;
- analysis of isotope geochemistry and fluid inclusion data;
- analysis and summary of petroleum geochemistry data;
- analysis of production data, histories and horizontal well technology;
- developing and managing a project Web site, database and GIS-IMS; and
- publishing a final report – a play book compilation and resource assessment.

Basement faults provide pathway for alteration by hot fluids

Evidence from the stratigraphic, structural, petrographic and geochemical tasks indicates hydrothermal dolomites in the Black River Group and overlying Trenton Limestone are the result of fault-related hydrothermal alteration of limestones. Carbonate beds in these two units were deposited on a relatively stable platform prior to major plate collisions that began in the Late Ordovician and continued into the Early Silurian. These collisions resulted in reactivation of old faults, or activation of new, basement-deep faults. High-pressure, high-temperature fluids moved up active, basement-rooted, strike-slip and transtensional faults during late Middle and early Late Ordovician time, until they encountered a low-permeable zone at the base of the Trenton Limestone (Figure 1). As the hot fluids moved laterally beneath this low-permeable zone, they cooled and leached limestone beds in the upper part of the Black River, enhancing permeability in these beds. Subsequent hot fluids that moved up the fault system were able to migrate farther from the faults, precipitating dolomite in the leached limestone zone, particularly on the downthrown sides of faults in negative flower structures. Matrix dolomitization was followed by further fracturing, brecciation and vug development as tectonic activity continued during subsequent plate orogenic episodes. The exploration model for Trenton-Black River hydrothermal dolomite reservoirs is to look for seismic evidence of subtle, basement-rooted wrench faults and negative flower structures that cut these limestones with evidence of movement within the first kilometer of burial. Faults with minor offset that do not extend far above the target formations are typically the best candidates because these faults have not breached the seal for hydrothermal fluids and hydrocarbons that were positioned later.

Two plays identified

The Trenton–Black River play is an expensive, high-tech, high-risk play that requires accurate interpretation of seismic data, including 3-D data. This analysis shows that future seismic programs should be concentrated over more favorable fairways, including: the Rome trough in Pennsylvania, West Virginia and eastern Kentucky; areas of higher density faulting associated with the current hydrothermal dolomite play in south-central New York; an area of similar faulting in northwest Pennsylvania; and around the margin of an area interpreted from isopach and facies maps of the Trenton Limestone as the Trenton Platform, extending from northwest Ohio eastward into northwest Pennsylvania, and then southwestward into West Virginia and southern Ohio (Figure 2) where it has been referred to as the Lexington Platform. These potential fairways help divide the Trenton–Black River gas play into two separate plays: a hydrothermal dolomite

(HTD) play on the western side of the basin; and a fractured limestone play on the eastern side of the basin.

The HTD play, which extends throughout the shallower portion of the basin, delineates areas where hot fluids rising up through basement-rooted faults could reach the Black River and perhaps the lowermost limestone beds in the overlying Trenton Limestone before they cooled or lost energy and flowed back down the faults into the basement (Figure 3). The play area includes the area of current activity in south-central New York and that of older Trenton–Black River production in northwest Ohio associated with the margin of the Trenton Platform. Clean limestones deposited around the margin of the platform are interpreted as being more prone to dolomitization than other facies types in these carbonate units.

The boundary between the HTD play and the fractured limestone play, although chosen based on a maximum thickness of rock between the top of the Black River and the basement through which hot, dolomitizing fluids have been shown to rise, approximates the western edge of the Rome Trough in much of Pennsylvania, West Virginia and Kentucky. The Rome Trough is an area of intense faulting and fracturing, and periodic reactivation of faults within the trough would fracture limestone beds in the overlying Black River and younger Trenton Limestone. Although the basement may be too deep in this area for hot rising fluids to reach and dolomitize limestones in the Trenton and Black River, it is probable that hot fluids have dolomitized limestones in older Cambrian limestone formations within and over the Rome Trough.

Future potential gas resource

The undiscovered gas resource was assessed for both these plays employing a modified version of the method used by the U.S. Geological Survey (USGS) in its resource assessments. During this assessment, the following factors were considered: formation thickness, richness and thermal maturation of organic matter in potential source rocks; regional stratigraphy and structural geology; discovery trends and sizes of current fields; and estimated ultimate recovery of existing fields. It was estimated there is a 90% probability of finding an additional 2.7-Tcf of gas in these two plays (a 1-Tcf increase over the USGS 1995 assessment); a 50% probability of finding 6 Tcf; and a 10% probability of discovering another 11 Tcf. The majority of this predicted gas resource is expected to be discovered in the HTD play area.

Acknowledgements and other related research

The Trenton-Black River Research Team organized by AONGRC to coordinate this research effort consists of the following recognized experts at the state geological surveys:

- *Kentucky*—David Harris, John B. Hickman, James A. Drahovzal and Paul D. Lake
- *Ohio*—Ronald Riley, Mark T. Baranoski and Larry H. Wickstrom
- *Pennsylvania*—John Harper, Chris Laughrey and Jamie Kostelnik
- *West Virginia*—Katharine Lee Avary, John Bocan, Michael Ed Hohn and Ronald McDowell
- *New York*—(from the State Museum Institute, an agency in the New York State Education Department) Richard Nyahay, Langhorn "Taury" Smith and Rose Schulze

The project also included 17 petroleum industry partners representing small to large companies that provided cost share and are developing this resource in the Appalachian Basin.

There are other reports that relate to the characterization of gas reservoirs in formations found in the deeper portion of the Appalachian Basin. These reports are available or will be in the near future on the NETL Web site (*www.netl.doe.gov*).

For additional information on this research (DOE Contract DE-FC26-03NT 41856) please contact Thomas H. Mroz, Project Manager, NETL, *thomas.mroz@netl.doe.gov* or (304) 285-4071. ✧

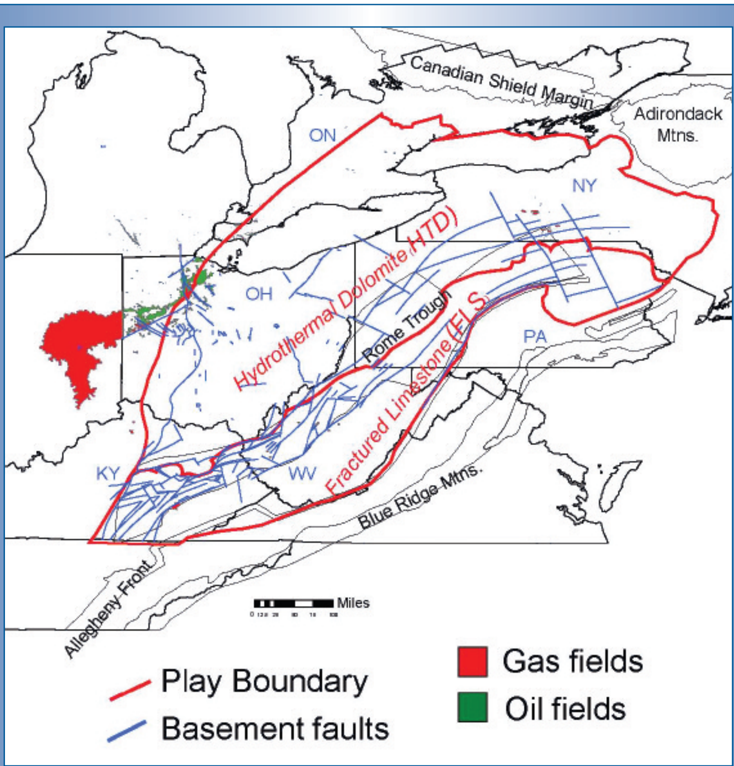

Figure 3. The above schematic shows the extent of the hydrothermal dolomite play, which includes the area of current activity in south central New York and the area of older Trenton-Black River production in northwest Ohio associated with the margin of the Trenton Platform.

Next-Generation Gamma Sensor for High-temperature Drilling

By Peter Sandvik, *GE Global Research Center;* and Jack Colborn, James Williams and David O'Connor, *GE Energy*

Under support from the U.S. Department of Energy's National Energy Technology Laboratory, GE Global Research (Niskayuna, New York) and GE Reuter-Stokes (Twinsburg, Ohio) are working together to develop an advanced gamma sensor.

As exploration and production (E&P) companies have looked for ways to grow their oil and gas reserves during the past 20 years, increasing drilling depths and complexity are often encountered. One example is the growing number of high-pressure/high-temperature (HP/HT) reservoirs. However, the capital intensive nature for E&P places pressure on reducing the costs of drilling wherever possible. Both these trends have resulted in a strong need to increase the reliability and capability of sensors and electronics used in oil and gas exploration.

Most of the sensors and electronics used today are capable of supporting extended drilling where temperatures reach 150°C. For drilling environments at 175°C, specialty tools are available but often only operate for short periods of time. New sensing and electronics technologies will be needed to not only increase existing downhole tool operating lifetimes, but also to support drilling requirements at 200°C and above.

Radiation sensors measure gamma rays that are naturally occurring in the Earth's formations or those reflected from formations that originate from sources in the drillstring. Gamma radiation is used in drilling operations to identify the sequence stratigraphy of the formations being drilled and to aid in the identification of potential reservoirs of fossil fuels.

Today's gamma sensor systems are comprised of several components. Commonly, two of these are a scintillator crystal, which converts gamma radiation into lower energies, such as visible, and a photomultiplier tube (PMT) to convert the visible light into an electrical signal for readout. An example of an existing system is shown in Figure 1. For the scintillator, sodium iodide (NaI) is commonly used as its output spectrum has good wavelength overlap with the response of the PMT. A PMT used as light output from the scintillator is typically on the order of a few thousand photons per gamma or less. The PMT is capable of producing a high ratio of electrons per incident photon, on the order of a million, resulting in current levels that may be readily processed.

Figure 1. An example gamma sensor system in current use.

There are several important limitations with today's system that prevent its long-time operation at or above 175°C. One of these is the instability of the photocathode material on the PMT, which suffers rapid degradation for those temperatures. This limits the time duration to which these systems are specified at 175°C, typically for about 1 year.

Sensor failures while drilling result in significant increased costs for the operators where drilling rig day rates can reach $200,000 or more. Often the oilfield service company must absorb this operator cost through lost service revenue that the sensor was originally intended to increase.

Avalanche photodiodes

To prevent such failures and increase downhole for drilling conditions that approach or exceed 200°C, a new gamma sensor system is being developed that will utilize a significantly different type of technology. In place of the PMT, an avalanche photodiode (APD) will be used, which will provide stability at those elevated temperatures while offering a high gain. Figure 2 shows a concept of this new gamma sensor system. Avalanche photodiodes are specialized photodiodes that operate in the breakdown regime, typically at a high reverse bias. The photo-generated electron-hole pairs resulting from incident light are subjected to very high electric fields internal to the device, where they undergo gain through charge carrier ionization. Through this process, gain may be achieved to provide a usable level of electric charge from the incident gamma radiation.

Because of the high temperatures required in the extended drilling application, silicon (Si) APDs, which are available and in common use, cannot be used. At temperatures near 200°C, conventional Si devices do not offer the long-term reliability required for useful operation as they are not physically stable. A more robust semiconductor material is silicon carbide (SiC), which has a bandgap of about three times that of Si. Silicon carbide has an intrinsic temperature higher than 800°C, allowing it to retain its semiconducting properties at temperatures well beyond 200°C. This property makes SiC an excellent candidate for the development of harsh environment sensors as well as electronics.

To date, multiple iterations of SiC APDs have been designed, fabricated and tested. These devices are complex, requiring careful design of their physical properties as well as their internal electric field profile in breakdown to maintain a high signal to noise ratio. Separate absorption and multiplication (SAM) APDs have been designed, and their performance is being optimized using standard semiconductor processing tools. Figure 3 shows a SiC APD and the current-voltage properties. The temperature dependence of the breakdown voltage in the APD is critical, as a it pertains to stability of the device and material quality. In the case of Figure 3, the APD breakdown voltage increases with increasing temperature as observed in previous work on 4H SiC devices, suggesting good device stability at elevated temperatures.

Recently, SiC APDs using the SAM structure were demonstrated for the first time, attesting to the feasibility and potential of this type of device. Gains of more than 1,000 were shown, with detectors exhibiting high quantum efficiencies (>80%) and uniform gain. With optimization, these devices should achieve very high signal to noise ratios, while operating at temperatures of 200°C and above.

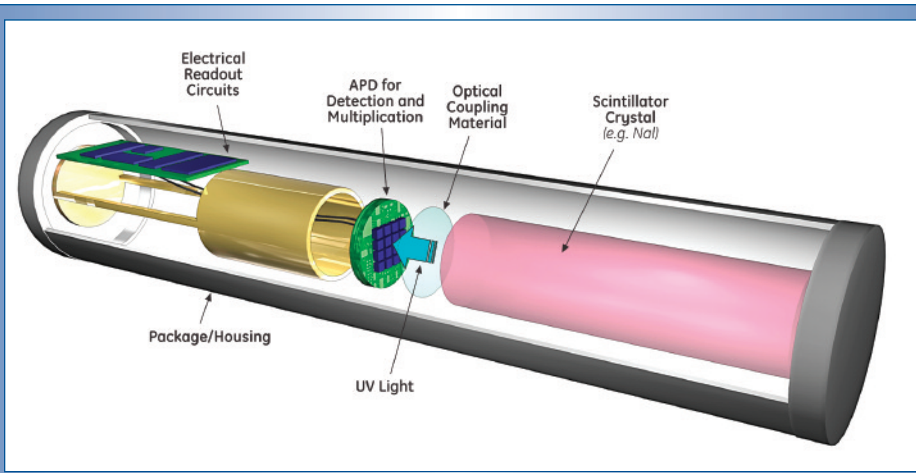

Figure 2. A concept drawing of the gamma sensor system under development. At left, an array of avalanche photodiodes is depicted, which is connected to read-out electronics. At right, a scintillator crystal is shown.

Novel scintillator materials

Because of its large bandgap ($E_g \cong 3.2$ eV for the 4H polytype), 4H SiC responds to ultraviolet (UV) radiation, and traditional diodes have peak sensitivity near 300 nm, and do not respond to visible light. Thus, NaI cannot be used as it outputs little light in the UV.

Under the same program, novel scintillator materials are being investigated for their potential use with the SiC APDs. The scintillator requirements also include high gamma stopping power, low background radiation and operability at temperatures up to 200°C and above. While few materials meet these criterion, some select candidates are under investigation for their manufacturability as well as their basic properties. In the first phase of the program, a powder study was carried out, exploring nearly 100 candidate materials for their key properties. This list was first narrowed down to just a few, where those selected for further study were the subject of crystal growth experiments.

To realize the desired scintillator properties, novel scintillator candidates are being grown to explore their characteristics in crystal form. In at least one case, a selected material has been grown for the first time to the best of our knowledge. This process has required the evaluation of basic growth conditions, crystal pulling rates and the use of alternate approaches to obtain as large a crystal as possible.

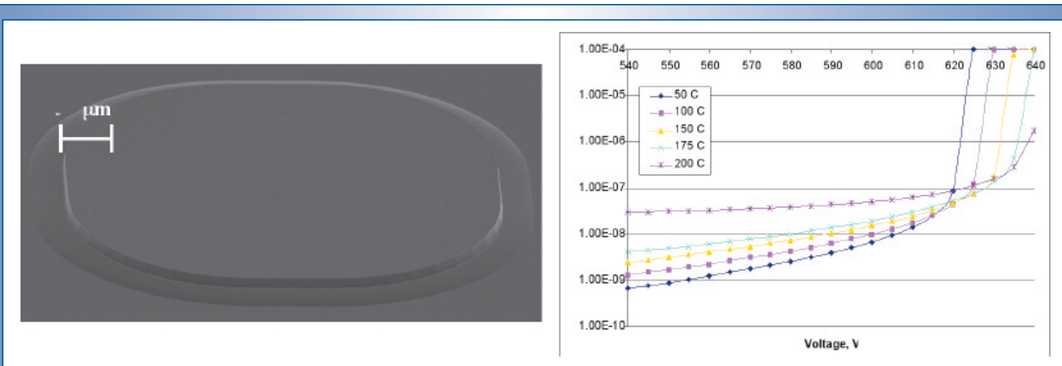

Figure 3. At left, a scanning electron microscope image shows the mesa feature in an avalance photodiode (APD). The top surface of this is the active area, where ultraviolet light from the scintillator will be detected and converted to an electrical response. At right, the current-voltage relationship of a silicon carbide APDs is plotted against temperature.

Other system components

Apart from the APD and scintillator materials development, other key system components are being investigated to support the next-generation gamma sensor system. One of the components is the design and implementation of the amplification electronics, which need to take into account the time response and gain requirements of the overall system. Another key component is the selection and preparation of the optical coupling materials, which will transfer light output from the scintillator to the APDs. Here, the materials should have a high index of refraction, high transparency in the UV and high temperature capability. Finally, the system housing will incorporate all of these materials and system sub-components, to handle the high vibration and temperatures. As much of the currently used gamma sensor system components will be used so the new system is easily integrated with downhole systems in current use.

To tie all of these components together, mathematical system models have been developed that enable the simulation of gamma sensor systems given assumptions about the components under development. As the APDs, scintillators, electronics and optical coupling materials are fabricated and measured, the system models will enable quick assessments of predicted system performance. Important metrics include minimum gamma energy as well as the energy resolution of the system. The anticipated performance of the new gamma sensor will be similar to the gross counting sensors available today; however, it will offer such use at temperatures up to 200°C, as well as extended reliability at lower temperatures in comparison to systems currently in use.

In conclusion, the gamma sensor will be able operate at more than 200°C and provide at least a factor of two to three increase in reliability over current technology for a temperatures at 175°C and above. The program will conclude next year with a prototype construction and reliability assessment at elevated temperatures. ✧

Acknowledgements

The authors are grateful for the project management support of Gary Covatch at the U.S. Department of Energy's NETL. Technical team members at GE Global Research include Robert Lyons, Stanislav Soloviev, Ho-Young Cha, Emad Andarawis, James Rose, Scott Zelakiewicz and Peter Waldrab. Finally, supervisory support at GE Global Research from Bruce Norman is appreciated, as well as help in preparing graphics from Richard Oudt.

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Microhole Coiled Tubing Drilling Successful in Niobrara Gas Play

By Kent Perry, *Gas Technology Institute*; and Jim Barnes, *National Energy Technology Laboratory*

An innovative approach of coupling coiled tubing drilling with ultra-small diameter wellbores slashes drilling costs, waste volumes and footprint size. A U.S. Department of Energy-funded project may have rendered a 1-Tcf natural gas play economic – a lesson applicable to other shallow, tight gas plays across the United States.

Figure 1. Rapid mobilization and demobilization of lightweight, easily transportable coiled tubing rigs is one of the keys to sharply reduced costs in microhole drilling.

A potentially game-changing new approach to drilling wells has been demonstrated successfully in the Niobrara natural gas play of western Kansas and eastern Colorado.

A hybrid microhole coiled tubing rig (MCTR) recently concluded the drilling of 25 test wells to the Niobrara formation, delivering cost savings of 25% to 35% per well drilled, as compared with conventional rotary drilling equipment.

In achieving the cost-savings in the Niobrara drilling program, the new technology could have rendered almost a trillion cubic feet of natural gas economic in that play.

This effort followed a U.S. Department of Energy (DOE)-funded project (DE-FC26-05NT15482, Field Demonstration of Existing Microhole Coiled Tubing Rig Technology) performed by the Gas Technology Institute (GTI) in Des Plaines, Ill., together with partners Advanced Drilling Technology LLC (ADT) and Rosewood Resources Inc. in Dallas, Texas.

The project is part of the DOE's Microhole Technology Initiative (MHT), managed by the National Energy Technology Laboratory. The project performers have submitted a final report, which is being reviewed and contains valuable operating and MHT program information to the drilling community.

MCTR roots

Much of the impetus for the MCTR project and the program itself stems from earlier DOE-funded research by Los Alamos National Laboratory (LANL).

In 1994, LANL advanced a concept for drilling holes with diameters ranging from $1\frac{3}{8}$-in. to $2\frac{3}{8}$-in. The concept for coiled tubing-deployed microdrilling systems evolved from theoretical studies and lab tests to field demonstrations in which boreholes with $1\frac{3}{4}$-in. and $2\frac{3}{8}$-in. diameters were drilled.

The laboratory subsequently undertook a DOE-funded project that further developed and evaluated its concept using modeling, lab tests and shallow field demonstrations at the Rocky Mountain Oilfield Testing Center. In that effort, it also identified key technologies needed to miniaturize existing equipment and develop new equipment to drill microholes to depths of 5,000ft.

In addition, LANL prepared a road map for a \$20-million, multi-year technology development program to further advance microhole technologies – the genesis of today's MHT program (see related sidebar).

Coiled tubing drilling

The laboratory's work paralleled a significant change under way in the coiled tubing industry overall. Operations prior to 1990 were largely limited to well intervention services such as the jetting of wellbores to clean up or start flow.

However, as stronger tubing, better tools and new technology have emerged, coiled tubing now can be used in almost any application rotary rigs can – given certain inherent limitations on wellbore length and reservoir conditions – and do it faster, easier and cheaper.

Although coiled tubing drilling accounts for only about 15% of the coiled tubing service industry, it is growing faster than the coiled tubing intervention market, according to a report sponsored by the DOE in June 2005.

Most coiled tubing drilling has occurred in Canada, for a variety of reasons detailed in the DOE report. Because of the niche that has emerged for coiled tubing drilling for coalbed natural gas, mainly in Western Canada, the number of coiled tubing wells

Microhole Technology Program Offers New Drilling Paradigm

The National Energy Technology Laboratory (NETL) Microhole Technology (MHT) Initiative is developing a promising suite of technologies to enable drilling of wells with less than 4½-in. diameter casings using coiled tubing rigs that are relatively small and easily mobilized. Once proven, these technologies could help reduce the cost of drilling shallow- and moderate-depth wells for exploration, development and a low-cost means of long-term subsurface monitoring.

The ultimate goal is to develop billions of barrels of oil and trillions of cubic feet of natural gas at shallow (less than 5,000ft) depths in the United States that are currently uneconomic. Using microhole technology could significantly lessen the environmental impacts of drilling by reducing volumes of drilling waste and the size of a well's operational footprint. It also could lower exploration risk by cutting the cost of drilling exploratory wells.

An added bonus of microhole technology is that it has the potential to deliver a low-cost method for deploying seismic tools to acquire continuous, high-resolution, real-time reservoir imaging without interrupting production.

The program's technology development focus is twofold:

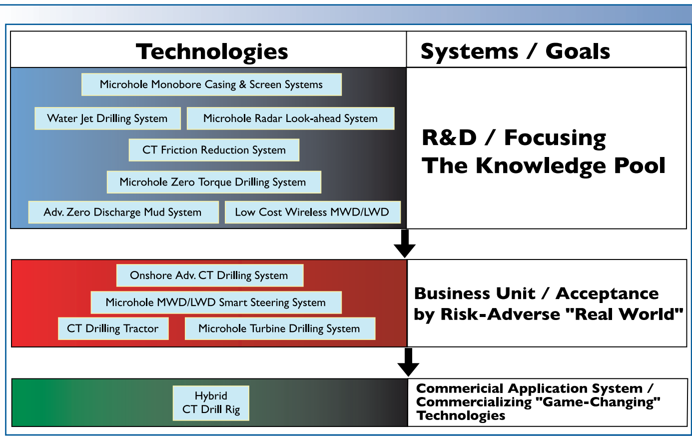
- conducting field demonstrations with existing coiled tubing rigs to show oil and gas can be economically recovered from wells drilled with casing smaller in diameter than 4½-in.; and
- developing an array of tools to drill, evaluate, complete and produce from lateral microholes drilled out of casing smaller than 4½-in.

Systems approach

The MHT program employs a systems approach by looking at the big picture and taking into account how various factors – technology, research, risk and the business environment – contribute to the success or failure of resource development.

In the case of microhole technology, the systems approach to resource development addresses these drivers:

- decreased cost of reservoir access to allow more holes to be drilled;
- reduced drilling footprints to minimize environmental impact;
- improved drilling efficiency to achieve high penetration rates; and
- cost-effective, high-resolution imaging to locate bypassed hydrocarbons and better manage sweep efficiency in enhanced recovery.



In this chart, the technologies being developed in the Microhole Technology program that are in the research and development stage are shown in the blue-shaded area. Microhole systems that are market-ready are shown in the red-shaded area. The hybrid coiled tubing drilling rig – shown in the green-shaded area – was used commercially immediately after project completion.

The MHT program's systems approach is depicted in the accompanying graphic.

Benefits

Microhole technology has the potential to cut the cost of drilling shallow- to moderate-depth exploratory wells by one-third and reduce the cost of development drilling by as much as 50%.

In the near term, expectations are that microhole technology could enable operators to drill shallow development wells with a third of the surface area and a third of the equipment loads when compared with a conventional rotary drilling rig. It also has the potential to allow re-entry of shallow wells to drill multilateral wells for economically accessing compartmentalized reservoirs. In addition, there is opportunity for drilling deep exploration tails in existing wells to cost effectively extend the wellbore to evaluate and produce new zones.

In the longer term, the MHT program's emphasis is on drilling dedicated wells to deploy seismic tools that enable high-resolution vertical seismic profiling and 4-D seismic imaging of reservoir fluid behavior and bypassed hydrocarbons; low-impact, high-resolution imaging of targets below environmentally sensitive areas; and passive seismic imaging.

For a more detailed look at the NETL's MHT program and the projects included, please see the Microhole Technology brochure at *www.netl.doe.gov*

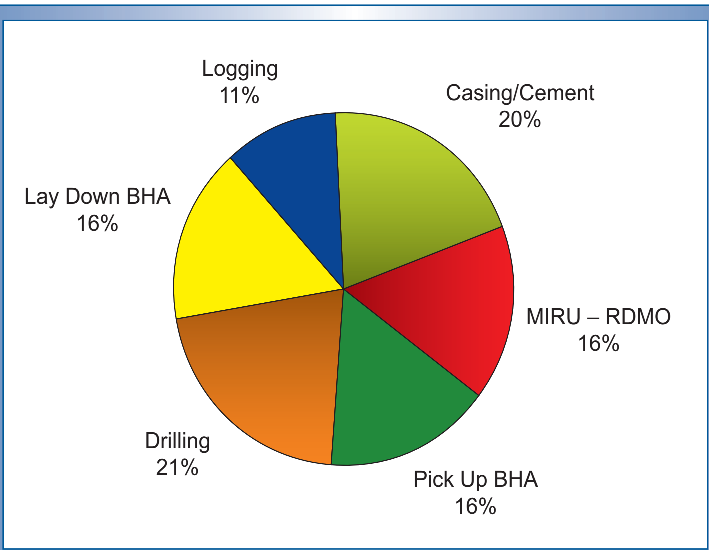


Figure 2. This chart shows the allocation of rig time for the Duell 3-17 microbore well. Total time was 20 hours.

Figure 3. The hybrid microhole coiled tubing drilling rig developed by Advanced Drilling Technology/Coiled Tubing Solutions Inc. delivered 25% to 35% cost savings per well drilled compared with conventional rotary drilling equipment, drilling 3,000-ft Niobrara wells in as little as 19 hours.

drilled has jumped an average 60% per year between 2002 and 2004, according to *Oil & Gas Journal.*

About 800 wells per year are drilled using coiled tubing in the United States.

Project objective

The main objective of the GTI project was to field-test a state-of-the-art hybrid coiled tubing rig by drilling a series of inexpensive microbore wells targeting a hydrocarbon resource that might not otherwise be economically recoverable with a conventional rotary drilling system.

The MCTR represents a critical platform for advancing the MHT program by demonstrating significant cost savings with rapidly drilled microholes as well as reducing the footprint and associated wastes of drilling operations (Figure 1).

The next-generation rig tested in the project is the MOXIE experimental rig fabricated by ADT and its predecessor Coiled Tubing Solutions Inc. (CTS). It was developed specifically for microhole coiled tubing drilling to depths as great as 5,000ft.

The Niobrara formation in Kansas and Colorado was chosen for evaluating the MCTR initially through a program that called for three wells and 1,000ft of 4¾-in. hole to be drilled in a shallow gas play between 1,200ft and 3,500ft.

The rig was evaluated according to the following criteria:

- mobilization and rig-up time;
- drilling surface and production holes;
- running surface casing and cementing;
- logging and evaluation;
- running production casing and cementing; and
- rigging down and moving the equipment from the drillsite.

During the project, measurements were made of time, equipment weight, rate of penetration (ROP), revolutions per minute, torque, drag, pumping pressures, mud properties, solids control and other measures of rig performance.

The project performers created a list of wells to be drilled to the Niobrara chalk along the Kansas-Colorado border. The first location, **Duell 3-17**, near Goodland, Kansas, was spudded May 13, 2005. It was drilled, logged and completed with 2⅞-in. tubing at a depth of 1,200ft. Drilling averaged 230ft/hour.

The second well, **Irvin 1-33**, was spudded May 14 following the rig move, then drilled, logged and completed with 2⅞-in. tubing at a depth of 1,390ft. The third well, **Gutsch 1-23**, was spudded May 15 following a rig move and drilled to a depth of 1,245ft.

Exceeding expectations

The MCTR performed beyond the scope of the original project. The rig drilled openhole wells ranging in depth from 500ft to 3,000ft for operator Rosewood, achieving ROPs from 300ft/hour to 620ft/hour. The average ROP was 400ft/hour.

The MCTR drilled a total of more than 40,000ft of 4¾-in. hole. Each well was monitored for rig performance, including ROP, rig mobilization time and other parameters.

The rig's performance improved progressively for the duration of the project. At first, 1,500-ft Niobrara wells were drilled in 1 day. Figure 2 shows the allocation of rig time for the Duell 3-17 well.

Later, 3,000-ft Niobrara wells were drilled in 19 hours. That included move-in, rig-up, drilling, logging, setting casing, cementing, and rig-down and move-out time (Figure 3).

The wells drilled resulted in a gauge hole with little hole deviation.

In early MCTR field-testing and monitoring, the percentage of time devoted to each operation was calculated as follows:

- rig-up, 9%;
- pick-up of bottomhole assembly, 9%;
- drilling, 26%;
- lay-down of bottomhole assembly, 9%;
- logging, 17%; and
- casing and cementing, 30%.

The relatively low amount of drilling time compared with conventional drilling illustrates coiled tubing drilling's time advantage in eliminating drill-pipe connections.

The GTI/ADT/Rosewood project's ability to exceed expectations was reflected in the honors it subsequently received. It was nominated as a finalist in the 2005 World Oil Awards and for Operator of the Year by the Colorado Oil and Gas Commission in 2005.

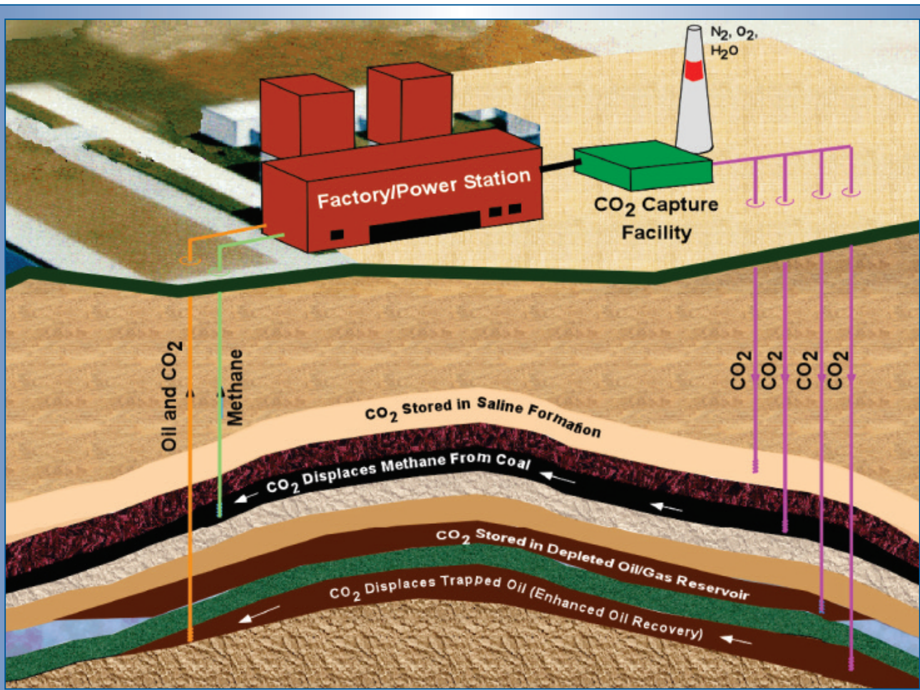


Figure 4. Options for geologic storage of carbon dioxide include enhanced recovery of oil and coalbed natural gas. Microhole coiled tubing drilling could be a cost-effective way to drill densely patterned carbon sequestration wells.

Benefits

Based on ADT/CTS's experience with coiled tubing drilling rigs in Canada, Kansas, Montana and Texas, microhole drilling can cut the cost of drilling by as much as 38%, which translates to a $55,000 savings per 1,500-ft well.

The MCTR design provides significant technical advances over conventional drilling systems in terms of reduced drilling costs, low mobilization and demobilization times, improved pipe-handling, increased safety, greater measurement-while-drilling effectiveness, reduced environmental impact and increased wellbore transmissivity.

When considered overall, the performance of the MCTR suggests a new approach for developing or redeveloping marginal gas fields. Wells that encounter thin pay zones with gas-water contacts near the perforated interval are being designed for production without hydraulic fracturing.

This approach, if proven successful, will allow production of previously nonproducible gas reserves.

The NETL has estimated the benefits in cost savings of microhole coiled tubing drilling with the natural gas industry alone at $8.4 billion during a 15-year period. In addition, the volume of drilling waste generated by conventional wells could be reduced by 103 million bbl with microholes, or to one-fifth the amount of waste volumes generated with conventional drilling.

Furthermore, the significantly reduced footprint could allow access to resources in environmentally sensitive areas via extended-reach drilling from smaller pads.

Another potential environmental benefit of microhole coiled tubing drilling could come amid growing efforts to capture industrial emissions of carbon dioxide (CO_2) for enhanced oil recovery and sequestering this greenhouse gas (Figure 4).

The DOE funded Phase 1 of the CO_2 Capture Project, an international effort by a consortium of energy companies to develop new technology to capture and store CO_2 currently emitted by fixed sources such as turbines, heaters and boilers. Some of these storage options could include efforts that would increase energy production as a consequence of CO_2 injection.

Microhole coiled tubing drilling could prove to be a critical enabling technology for drilling densely patterned carbon sequestration wells for such a CO_2 capture program. ✧

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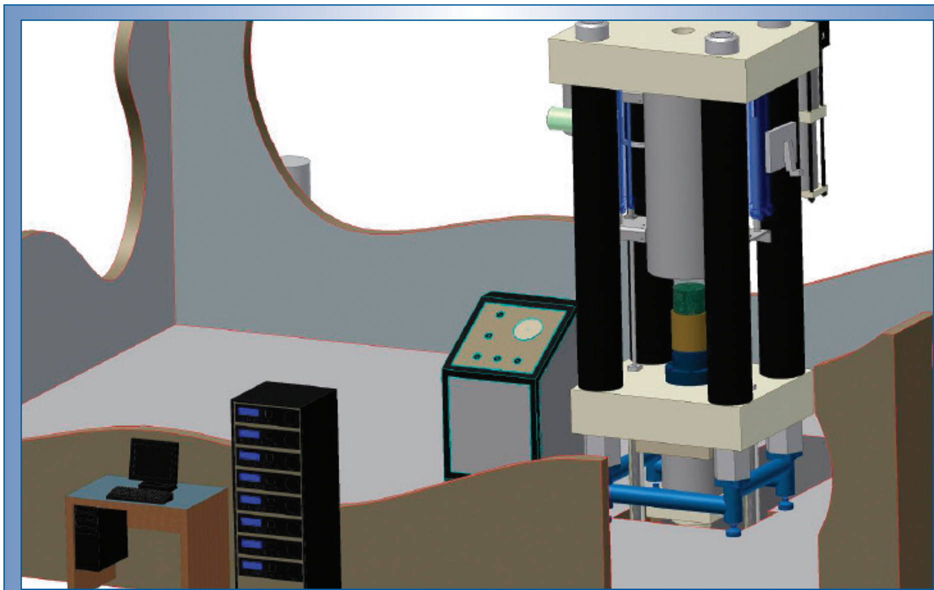
Extreme Drilling Laboratory to Advance Understanding of Bit-Rock-Fluid Interaction

By K. David Lyons,
National Energy Technology Laboratory

Tasked with providing critical science needed to engineer effective and efficient drilling technologies viable at depths greater than 20,000ft, the National Energy Technology Laboratory is establishing an Extreme Drilling Laboratory.



Preliminary conceptual design of the Ultra-deep Drilling Simulator (UDS) Test System. Some pressure containing elements are not shown so that test rock specimen can be illustrated.

The lab will be well positioned to deliver scientific understanding that will enable new technologies capable of pushing the envelope of practical high-pressure, high-temperature (HPHT) drilling beyond current limits. These advances will make drilling at temperatures in excess of 481˚F and pressures up to 30,000psi feasible, opening the door to development of deep hydrocarbon resources.

The Extreme Drilling Lab (EDL) will employ computational and physical simulation. The combination of computer modeling and physical simulation provides a unique capability, especially useful when the extreme conditions of the HPHT operating envelope are considered. This approach will permit the validation of each ultra-deep drilling simulation technique, something that has never been previously achieved. The 391˚F to 571˚F temperature window is a transition point for many types of rock, where rock behavior cannot be adequately described by either plastic or elastic behavior models. The EDL activities will generate unique, previously-unrecorded experimental data related to cutter, rock and drilling fluid interaction in HPHT environments. The generation and analysis of such data along with model development will assist industry in building a more thorough understanding of the influence of temperature, pressure, mud properties, bit design and drilling parameters on drilling rate of penetration (ROP). Ultimately, this understanding will enable the design and application of bit/fluid systems that can optimize ROP, lowering the cost of deep drilling.

The UDS physical simulator

The Extreme Drilling Laboratory's physical simulation capabilities stem from the NETL's multi-year participation in a cooperative agreement with TerraTek, which has recently become a Schlumberger company, titled *Ultra Deep Drilling Cost Reduction* (Project DE-FC26-05NT42654). As part of this agreement, an ultra-deep single cutter research drilling simulator (referred to as the UDS System) is being designed and constructed to study fundamental behavior and interactions among drilling fluids, bit cutters and rock under HPHT conditions. HPHT drilling systems of interest are being evaluated at fluid pressures from 15,000psi to 30,000psi and rock temperatures from 391˚F to 571˚F, conditions found at depths exceeding 20,000ft.

The UDS design employs rotation of the rock sample against a stationary cutter. A three-axis load cell outfitted with high speed data acquisition will record test variables of interest (see graphic). Within the cell, drilling fluids are maintained at bottomhole conditions and in intimate contact with the cutter and rock, as every effort is made to provide realistic drilling mud hydraulics. The UDS system will utilize a pressurized mud system where the mud is continuously circulated in a closed loop, which will enable continuous pumping while pressure drop across the nozzle is varied, permitting a variety of fluid hydraulic conditions to be tested. The selection and placement of the mud injection nozzle near the cutter will be a degree of freedom for a given test and is the primary mechanism for altering the conditions to obtain the mud hydraulics of interest for a particular experiment.

An advanced feature planned for the system is a capability for X-ray observation of the cutting process. This is designed to provide visualization of the rock-cutter-fluid interface during a cutting event, which some modes of interest may have duration on the order of milliseconds or less. By using X-ray observation techniques, it will be possible to physically observe the solid-phase flow of rock over extremely small time increments. Observations of rock strain under the bit and the generation and flow of rock cuttings will be critical in determining the fundamental mechanisms of rock failure and chip formation under a drill bit. The use of X-ray observation has been selected because the lack of transparency of most drilling fluids substantially limits optical observation. However, for clear drilling fluids, optical observations can be made and compared with those acquired using the X-ray system.

Computer modeling: development and validation

To develop a comprehensive understanding of HPHT advanced drilling mechanisms, the NETL is developing numerical, computer simulators to model drilling processes concurrently with the physical simulation activities described. Capturing the physical observations from UDS testing into numerical modeling algorithms will enable the quick and inexpensive application of the models to a variety of other HPHT drilling situations. Most importantly, this will occur within a forum available to the entire industry, which will allow widespread application to a variety of problems. The ability to validate a cutter-rock model with a comprehensive physical experiment is a unique capability that the NETL will be able to offer to the oil and gas industry as it strives to reach and produce from increasingly deeper reservoirs.

At a minimum, the numerical model will complement the experiments carried out using the UDS by serving as another, cheaper, means of performing experiments. However, the numerical model's contribution is likely to be much more significant as it offers opportunities to develop new theories for rock failure and chip formation under a drill bit, especially in the HPHT context. When computer modeling of HPHT drilling becomes refined through validation with UDS data and physical observation, it may well become the NETL's most tangible contribution to the future success of the drilling industry.

Initially, the computer modeling component of the EDL will utilize the FLAC3D software tool, which allows for users to define new failure modes and mechanisms in addition to the built-in models. Often times, defining user-developed models can be risky, but when coupled and validated with physical data, the use of user-defined models becomes a strength.

Many of the NETL's computer modeling activities have grown out of collaborative efforts with various universities. By combining the unique strengths of the NETL's in-house personnel and facilities with the academic strengths of university programs, while maintaining relationships with industry groups, there is a strong likelihood of significantly improving the current technology and practices associated with deep drilling.

Project timeline

The design and construction of the UDS Test System is scheduled to continue through the remainder of this year. The construction and debugging at TerraTek's facility in Salt Lake City is scheduled for the first half of next year. After the system passes through these stages, it will be delivered and commissioning at the NETL's campus in Morgantown, West Virginia. The timetable of these milestones remains a bit fluid as development of the UDS Test System requires prototype development of critical elements such as special seals, an X-ray imaging system, components designed for high-temperature corrosion resistance and in-vessel transducers. The NETL continues to plan for UDS commissioning for the middle of next year.

The computer modeling activities kicked off this summer, a year ahead of planned UDS operation. A team of researchers from West Virginia University and Carnegie Mellon University has been selected to collaborate with NETL personnel to develop a FLAC3D model of a single cutter interacting with the rock surface. The cutter-rock model will eventually be used for analyzing the influence of temperature, pressure, formation and mud properties, bit design and drilling parameters on the cutting process as well as drilling ROP. This cutter-rock model will also be used to back-analyze the experiments carried out using the UDS to calibrate, validate and optimize the simulated rock mechanics theories and advanced failure mechanisms. In the future, the model will be modified to handle multiple cutters.

Collaboration with other universities is being encouraged and will likely occur as the EDL gains more functionality. There will be opportunities for university graduate and post-doctorate work.

After the UDS System is commissioned and the initial activities bear meaningful results, the NETL anticipates involvement with industry via Cooperative Research and Development Agreements (CRADA), and similar relationships, possibly as early as 2008. In addition to working with industry via CRADA, the EDL will be contributing to published research in peer-reviewed journals, industry trade publications, and industry-sponsored conferences and meetings.

For more information on this project or to explore future opportunities to collaborate, contact K. David Lyons at the NETL at *k.david.lyons@netl.doe.gov* or (304) 285-4379. ✧

DOE Selects Projects Targeting Deep Natural Gas Resources

The U.S. Department of Energy announced the selection of seven cost-shared research and development projects targeting America's vast, but technologically daunting, deep natural gas resources. These projects focus on developing the advanced technologies needed to tackle drilling and production challenges posed by natural gas deposits lying more than 20,000ft below the Earth's surface where drillers and producers encounter temperatures greater than 400˚F and pressures greater than 15,000psi as well as extremely hard rock and corrosive environments. For more information, visit *www.netl.doe.gov/publications/press/2006/06036-Deep_Drilling_Technology_Awards.html*

DOE Selects Projects Targeting America's Tight Gas Resources

The U.S. Department of Energy has announced the selection of two cost-shared research and development projects targeting America's major source of natural gas: low-permeability or tight gas formations. Tight gas is the largest of three so-called unconventional gas resources – the other two are coalbed methane (natural gas) and gas shales. Production of unconventional gas in the United States represents about 40% of the nation's total gas output in 2004, but could grow to 50% by 2030 if advanced technologies are developed and implemented. For more information, visit *www.fossil.energy.gov/news/techlines/2006/06042-Unconventional_Gas_Projects_Announ.html*

DOE-Funded R&D Will Help Producers Tap America's Deep Natural Gas Resources

A U.S. Department of Energy research program has achieved major milestones in the development of "smart" tools that enable cost-effective finding and production of huge gas resources lying 3 miles to 5 miles below the Earth's surface. Successful tests of four electronic components developed by Honeywell Inc., Plymouth, Minn., point to another watershed in the successful Deep Trek research program DOE established in 2002. Deep Trek was created to address the extreme temperatures, pressures and other harsh conditions encountered when drilling below 15,000ft to 20,000ft. To date, the DOE has awarded eight projects under the Deep Trek program totaling more than $16 million, almost $9 million of which is being contributed by research partners. For more information, visit *www.netl.doe.gov/publications/press/2006/06031-Deep_Trek_Milestones.html*

Revolutionary 'Smart' Drillpipe Creates Downhole Internet

A U.S. Department of Energy-funded technology that establishes a "downhole Internet" for drilling oil and natural gas wells is now available for commercial use. The technology turns ordinary drillpipe into a highway for transmitting drilling and geological formation data at blazing speed from the bottom of a well to the surface and vice-versa. The potential benefits of the new technology include decreased drilling costs, improved safety and reduced environmental impacts of drilling. Grant Prideco's announcement of the commercial launch of its IntelliServ Network and related Intellipipe technology capped 5 years of research sponsored by the DOE and managed by its National Energy Technology Laboratory. For more information, visit *www.netl.doe.gov/publications/press/2006/06026-Intellipipe_Goes_Commercial.html*

DOE Researchers Developing Technology to Safely Detect Flaws in Plastic Gas Pipelines

The U.S. Department of Energy's National Energy Technology Laboratory is developing the first technology that can detect flaws in plastic natural gas pipelines without disrupting pipeline operations. It potentially is applicable to almost one-quarter of the nation's natural gas pipeline system. Safe and inexpensive, the new technology deploys a tiny robot inside plastic pipelines. The robot carries a sensor controlled by a microcomputer that can identify cracks, dents, pinholes and other anomalies by measuring variations in electric fields on the outside of pipe walls. The technology allows inspection of plastic pipelines from the inside without interrupting the flow of gas, taking them out of service or digging them up. It can detect potential gas pipeline failures in advance of a rupture. For more information, visit *www.fossil.energy.gov/news/techlines/2006/06041-Sensor_Detects_Pipeline_Flaws.html*

Publications

DOE R&D Puts Carbon Dioxide Enhanced Oil Recovery On The Verge Of Explosive Growth

Technology advances, higher oil prices, reduced costs and environmental needs have aligned to create a strong growth opportunity for a well established method for enhancing oil recovery in the United State: carbon dioxide flooding. A new brochure is available detailing DOE funded activities at *http://www.netl.doe.gov/technologies/oil-gas/publications/brochures/CO2Brochure_Mar2006.pdf*

New Document Details Potential Natural Gas Demand for South Central and Other Areas of Alaska

The document, *Alaska Natural Gas Needs and Market Assessment*, details potential natural gas demand for South Central and other areas of Alaska directly associated with a potential spur pipeline connecting the proposed Alaska North Slope Gas Pipeline to the Cook Inlet pipeline infrastructure. The report is available at *www.netl.doe.gov/technologies/oilgas/publications/AEO/AlaskaGasNeeds-MarketStudy.pdf*

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