National Energy Technology Laboratory
Office of Petroleum Newsletter

E&P Focus

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DOE's microhole program could spur revolutionary approach to U.S. oil well drilling

Department of Energy-funded "microhole" technology could usher in a revolutionary new approach to the way America's oil and gas wells are drilled.

The targeted result: greatly reduced costs and environmental impacts and a wave of new drilling that could help bolster the Nation's energy security.

And if progress continues apace for DOE's microhole research and development program, the technology could be on the cusp of commerciality in just a few years.

DOE's microhole initiative centers on developing technologies related to drilling wells with diameters smaller than 4¾ inches and deploying downhole microinstruments specially designed for such small holes.

The idea is to use smaller, transportable drilling rigs to dramatically cut the costs and risks of drilling wells for oil and gas producers while shrinking the "footprint" of drilling operations and reducing related waste volumes.

The microhole technology program is managed by the Office of Petroleum of the Strategic Center for Natural Gas and Oil, an arm of DOE's National Energy Technology Laboratory. NETL early this year announced the second phase of its microhole initiative. This year's round was designed to push microhole technology another step closer to commerciality and widespread adoption by the U.S. oil and gas industry.

"This [second round] is the first solicitation round for demonstrations of advanced technology that might become the future of significantly reduced costs for exploration and development," said Roy Long, Exploration and Production Technology Manager for SCNGO's Office of Petroleum. "Within 3 years, we'll know whether we have commerciality for most of these technologies."

New paradigm

As industry broadly embraces this technology, the upshot could be a sea change in the way that the Nation's hydrocarbon producers explore for oil and gas and drill and monitor wells.

Widespread adoption of microhole technology could spur a wave of "infill development"—drilling wells spaced between existing wells—that could tap an enormous resource of bypassed oil lying at shallow depths in mature producing areas that is not economic to recover with current technology.

In most of the world's oil reservoirs, primary recovery of the original-oil-in-place generally is limited to 20%. Even the most advanced secondary and tertiary recovery technologies seldom push that recovery factor much beyond 50%. In other words, about half of the oil in discovered reservoirs remains untapped with current technology and economics.

DOE estimates this untapped resource—at least that portion of it at less than 5,000 feet subsurface—at 218 billion barrels of oil in the U.S. Recovering just 10 percent of this targeted resource would mean producing a volume equivalent to 10 years of the Nation's imports of oil from OPEC at current rates.

DOE analysis shows that microhole technology has the potential to cut exploratory drilling costs by a third or more and to slash development drilling costs by more than 50 percent.

Inside

The technology's benefits go beyond reducing costs. Microhole and related microinstrumentation technologies offer the opportunity to greatly reduce producers' exploration risk to a level comparable to that of drilling development wells.

Such prospects are especially appealing to the small, independent producers who drill over 85% of the Nation's oil and gas wells and produce 60% of its natural gas and 40% of its oil (over 60% of oil in the Lower 48 states). Producers drilled about 10,000 infill development wells shallower than 5,000 feet in the U.S. last year.

continued on page 2

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— Roy Long, E&P Technology Manager for SCNGO's Office of Petroleum

continued from page 1

"With the microhole technology program, DOE has tapped into an area of significant industry need," said Long. "Microhole technology is the only real solution…that offers the potential to lower exploratory risk to that of development risk. The entire scope is to drive down drilling costs and reduce exploration risk."

Technology benefits

Microhole technology involves adapting conventional coiled tubing drilling techniques to ultrasmall-diameter boreholes. Coiled tubing drilling entails deploying a drill motor and bit on the end of slender tubing that is coiled around a spool on a trailer pulled by standard pickup truck. That is a far cry from the much wider, heavier sections of jointed pipe used in drilling most wells and from the big land drilling rigs whose transportation requires large amounts of expensive, specialized equipment.

With coiled tubing drilling, operators are able to reduce drilling costs dramatically. The savings come from being able to utilize a drill site as much as two thirds smaller, use much smaller equipment for handling pipe and tubing, and cut back on drilling and well-completion materials.

The same advantages that accrue to the lower costs also spawn environmental benefits. When drilling equipment is smaller and more portable, the "footprint" of the drilling operation is smaller, lessening the impact of the rig on the ecosystem—an especially critical factor in remote, fragile terrains. In addition, the much smaller-diameter holes—especially in conjunction with zero-discharge drilling mud systems—produce greatly reduced waste disposal volumes.

Oil and gas operators deploying microhole technology would be able to economically re-enter existing wells to increase production from bypassed zones. Thus operators will have the capability to readily deepen thousands of the Nation's wells in search of the myriad exploration targets lying at greater depths.

A key to advancing the microhole technology initiative is the development of economic, new high-resolution seismic methods for subsurface imaging with microelectromechanical systems technology. This effort is expected to result in unprecedented seismic imaging using miniaturized sensors. Such miniature sensors now under development are demonstrating performance capabilities approaching that of conventionally sized seismic equipment. That is a crucial watershed, because equipment placed in a well must be able to withstand the temperature and pressure conditions often encountered downhole.

Such an advance in miniaturized sensors will enable operators to develop low-impact, high-resolution seismic methods for targeting exploration prospects. It also will allow producers to develop a low-cost, long-term means of monitoring for improved imaging of fluids moving through the reservoir during their efforts to boost recovery of oil, especially the bypassed oil in mature fields.

Los Alamos National Laboratory's coiled tubing microdrilling unit used in field demonstration.

In addition, microhole technology's reduced costs will spur producers to economically monitor their reservoirs permanently without interrupting production. A relatively new capability, Vertical Seismic Profiling, is referred to as "designer seismic" because it enables, for the first time, a geophysicist to pick the location of the seismic instrument package rather than use an existing well while production is shut in. In this way, data can be collected where and when needed rather than where production or injection wells have been drilled.

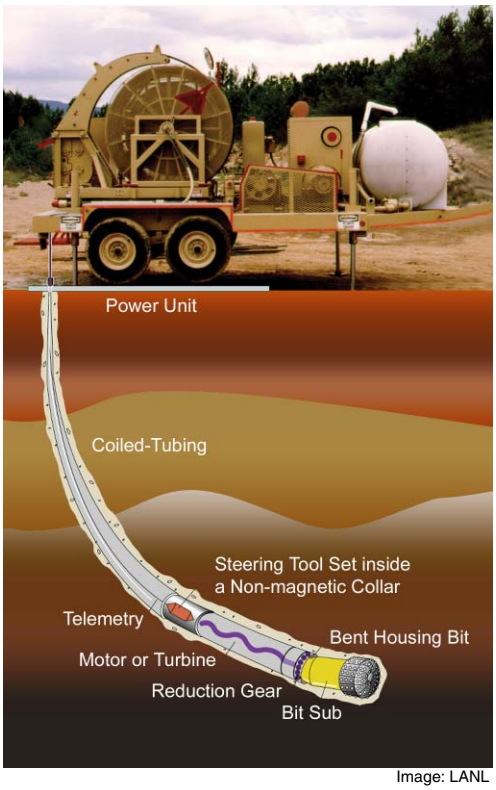

Image: LANL

This early success offered a tantalizing look at the possibility that microholes could assume a major role in boosting recovery from America's oil and gas fields.

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Commercialization targeted

The NETL Microhole Initiative has its roots in feasibility studies and a field demonstration of coiled tubing-deployed microdrilling together with miniature seismic sensors that were conducted by Los Alamos National Laboratory and its industry partners.

The Microhole Initiative's first solicitation focused on field demonstrations and development of technologies needed to deploy coiled tubing microhole drilling in the field. Specific target areas included a field demonstration; a built-for-purpose microhole coiled tubing drilling rig; a self-contained, zero-discharge drilling mud system; microhole coiled tubing bottomhole assemblies; and microhole completion and production equipment.

This first solicitation, announced in June 2004, involved six projects valued at nearly

$5.2 million. The second round, announced in January 2005, involved 10 projects, valued at nearly $14.5 million, that emphasize implementation of more field demonstration projects in addition to technology development projects (see sidebar, this page).

The goal is nothing short of commercializing this promising new area of oil field technology.

It all adds up to a potential revolution in the way America's oil and gas wells are drilled—one that dovetails with the Bush Administration's goal, set forth in the National Energy Policy, of promoting "dependable, affordable, and environmentally sound" domestic energy production.

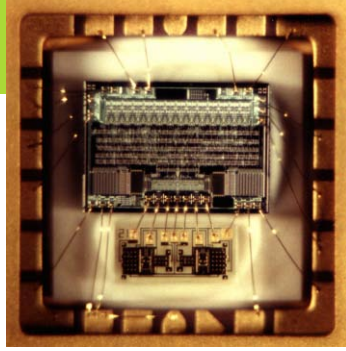


Photo: Silicon Designs

An example of MEMS (microelectromechanical sensors) being developed for DOE's Microhole Initiative.

DOE announces second round of R&D Funding for Microhole Technology Projects

The Department of Energy in January 2005 announced the award of funding for 10 projects that are designed to push microhole technology another step closer to commerciality and widespread adoption by the U.S. oil and gas industry. It was the second round of funding under the Microhole Initiative the agency had announced in less than a year.

The 10 new projects are:

Geoprober Drilling Inc. (Houston, TX)—This project calls for drilling three wells with an innovative composite coiled tubing drilling system. The aim is to confirm the capability to drill low-cost, shallow slim/microhole exploration wells in water depths ranging up to 10,000 feet. (DOE share: $1 million; Project duration: 12 months)

Gas Technology Institute (Des Plaines, IL)—This project entails a proposal to field test a next-generation microhole coiled tubing rig. The MOXIE experimental rig was fabricated by Coiled Tubing Solutions (Dallas, Texas) specifically for coiled tubing and microhole drilling to 5,000 feet subsurface. GTI will assess field tests and lead a technology transfer program. (DOE share: $1 million; Project duration: 12 months)

Confluent Filtration Systems LLC (Houston, TX)—Researchers will seek to develop a revolutionary elastic-phase, self-expanding tubular technology called CFEX. CFS's goal is to develop self-expanding well casings to any diameter, leading to improved methods and feasibility of monobore drilling and well construction. (DOE share: $1 million; Project duration: 36 months)

Tempress Technologies (Kent, WA)—The goal of this project is to develop a small, mechanically assisted, high-pressure waterjet drilling tool. A downhole intensifier would boost the pressure that can be delivered by coiled tubing, maximizing drilling rates. (DOE share: $800,000; Project duration: 24 months)

CTES LP (Conroe, TX)—Researchers will focus on improving performance and reliability of microhole coiled tubing drilling bottomhole assemblies while reducing cost and complexity associated with drilling inclined/horizontal well sections greater than 2,000 feet. The goal is to enable operators to economically use coiled tubing to drill microhole sections greater than 3,000 feet in horizontal wells. (DOE share: $700,000; Project duration: 24 months)

Technology International Inc. (Kingwood, TX)—This project entails developing and testing an effective downhole drive mechanism and a novel drill bit for drilling with coiled tubing. The high-power turbodrill will deliver efficient power at relatively high revolutions per minute and low bit weight. The more durable drill bit will employ high-temperature cutters that can drill hard and abrasive rock in 3½-inch boreholes. (DOE share: $800,000; Project duration: 24 months)

Ultima Labs Inc. (Houston, TX)—This project is intended to combine existing technologies for measurement-while-drilling (MWD) and logging-while-drilling (LWD) into an integrated, inexpensive measurement system to facilitate low-cost coiled tubing drilling of small-diameter (3½-inch) wells at depths shallower than 5,000 feet. Two prototypes are to be delivered ready for field testing. (DOE share: $800,000; Project duration: 36 months)

Baker Hughes Oilfield Operations Inc. (Houston, TX)—Researchers will seek to provide a critical tool essential for an effective modular coiled tubing drilling system: a wireless system to help steer drilling in a microbore. Plans also call for developing a downhole bidirectional communication and power module and a surface coiled tubing communication link. (DOE share: $800,000; Project duration: 24 months)

Gas Technology Institute (Des Plaines, IL)—This project entails designing, developing, and evaluating a counter-rotating motor drilling system ideally suited for reducing costs associated with drilling wells targeting unconventional gas. By concentrating the weight on the drill bit in a smaller area and by addressing the limited torque on a coiled tubing drill string, this research would increase the effectiveness of coiled tubing drilling. (DOE share: $600,000; Project duration: 24 months)

Confluent Filtration Systems LLC (Houston, TX)—Another major concern for microhole drillers is the damage caused to casing from sand that infiltrates the drill string. Accordingly, there is a great need for downhole sand screens that are versatile and robust while being suited for a variety of drilling environments. This project is designed to prove and develop a concept for a self-expanding, high-flow sand screen that could be constructed from a wide range of materials. (DOE share: $200,000; Project duration: 24 months).

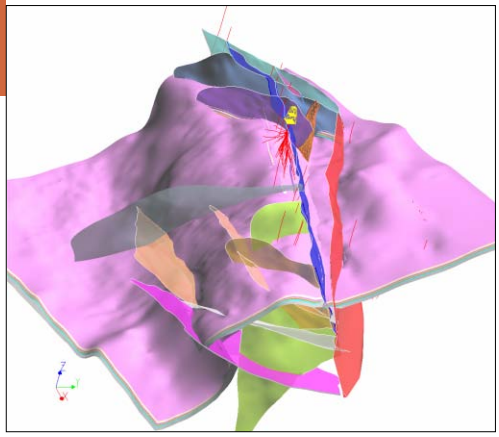
New technology improves modeling of scrambled geology off California

The geology encountered in drilling oil and natural gas wells offshore California can be as complicated and daunting as the politics of offshore drilling in that state.

Department of Energy-funded research is helping a small California independent overcome both hurdles. The lessons learned from this research could help other operators tap a California oil resource with potential measured in the billions of barrels, thus also helping the Nation's energy security.

The Miocene Monterey can be a devilishly complex geological formation off the coast of California. While it serves as the source rock for most of the oil found in the state, as a producing reservoir west of the San Andreas Fault it is characterized by complex faulting and fracture patterns. The Miocene Monterey chert also tends to produce at a very high water cut. This combination of features explains why an oil field such as South Ellwood in the Santa Barbara Channel off California, while holding more than 2 billion barrels of original-oil-in-place, has produced only 54 million bbl since its start-up in 1972. The crazy-quilt geology of the Monterey chert at South Ellwood had resulted in cumulative individual well production rates ranging from almost 10 million barrels to as little as 260 barrels. And high water cuts have severely squeezed the economics of the South Ellwood wells.

Beyond those challenges, a leasing ban persists off California, part of a political climate that has chased many major oil companies away from the state's prolific offshore fields and prospects. In recent years, however, a number of independent oil companies have stepped in to continue exploration and development drilling on these properties in an environmentally responsible manner—in the world's most stringent environmental regulatory regime. Because of the leasing ban, consideration has been given to drilling extended-reach wells from existing platforms or from shore to develop more of the discovered oil.



3-D image of cross section of Monterey strata.

When small independent Venoco Inc. of Carpinteria, CA, acquired the South Ellwood field in 1997, it saw significant upside potential from a program of well workovers and infill drilling. But Venoco sought to reduce its risk before launching an aggressive redevelopment of the field.

DOE granted Venoco a $3 million joint study, in partnership with the University of Southern California, to research solutions to the problems the independent faced at South Ellwood. The first priority was to map and characterize the fracture patterns and the reservoir conduit system across the field. But adequate reservoir characterization seemed out of the question because state law bans seismic surveys in the channel to protect marine mammals there.

The project instead enabled the purchase of an off-the-shelf program that allowed extensive reprocessing of existing seismic data extending back to 1982. In addition, a new algorithm was developed under the project that could be used to interpret fault patterns. The reprocessed data and the algorithm helped the operator locate new subsurface targets and design new well path trajectories. The reprocessed data enabled the targeting of three previously unknown fault blocks with reserves put at over 80 million barrels of oil.

The first well that was drilled as a result of this new geological model came in at a daily flow rate of more than 812 barrels of oil and 2 million cubic feet of natural gas, paying out its cost in less than a year. More importantly, the knowledge gained from the project—notably the innovative fracture network reservoir simulator—is being shared with other operators. Many oil fields in California produce from the Monterey, onshore and offshore, and feature analogous fractured reservoirs. At least two other operators producing from the Monterey have reported using the same techniques as those developed under the project to boost their production.

ADIS imaging/modeling tools key to Office of Petroleum mission

Subsurface imaging and modeling tools are critical to the U.S. oil and gas industry's efforts to find and recover the billions of barrels of oil that remain untapped in America.

The Office of Petroleum's Advanced Diagnostics and Imaging Systems (ADIS) is focuses on solving problems and reducing risk in all exploration, development, and production operations. ADIS targets technology developments in seismic and other imaging technologies, geological modeling tools, and reservoir characterization and modeling.

Operators face a host of challenges in visualizing and mapping the many unique subsurface rock geometries, fractures, and structural/stratigraphic settings that characterize where oil reserves are found. ADIS promotes cross-cutting interdisciplinary research to overcome these challenges, thus enabling cost-effective E&P.

ADIS processes

ADIS processes are designed to develop technology to:

- Increase accuracy and resolution of imaging of oil reservoirs.
- Provide detailed reservoir architecture, rock fluid distribution, and fluid-flow properties to maximize production in new and mature fields.
- Foster the use of data collection and analysis techniques for reservoir characterization and to integrate these data to maximize ultimate recovery, define additional potential, and reduce risks associated with oil exploration, development, and production.
- Develop new geologic models and exploration concepts of basin analysis.
- Integrate multiple processes and reservoir models for maximum economic recovery.
- Improve E&P data acquisition, processing, modeling, and interpretation.
- Implement regional geologic studies and basin analyses.
- Characterize petroleum reserves for better recovery.

ADIS project details can be found at **www.netl.doe.gov/scngo/petroleum**

MEOWS system potential livesaver for America's stripper oil wells

Microcontroller and radio modem circuits.

Photo: Honeywell Inc.

Small independent producers operate the vast majority of America's oil wells on the thinnest of margins.

Maintaining production efficiencies in so-called "stripper" oil wells—those producing less than 15 barrels of oil per day—thus can mean the difference between survival and an early demise for those wells. Frequent or extreme declines in those efficiencies can force a choice between shutting the wells down or operating them at a loss. But monitoring efficiencies of wells in real time every day can be costly; it usually entails high-tech data systems reserved for big-volume oil and gas wells such as those found in the Gulf of Mexico.

A DOE-funded project has developed a new, ultralow-cost method for monitoring marginal oil wells that promises to help rescue thousands of U.S. oil wells from that early demise.

The success of such an approach could have huge implications for America's small independents. The more than 400,000 stripper oil wells in the U.S. produce almost 1 million barrels of oil per day, or 20 per cent of the Nation's oil output. More than 150,000 marginal oil wells were abandoned during 1993-2000, costing the U.S. more than $3.5 billion in lost economic output and leaving about 150 million barrels of crude in the ground. A low-cost solution to the stripper well monitoring problem promises to keep tens of thousands of wells pumping for America's small independents.

MEOWS system

The DOE-funded MEOWS (Marginal Expense Oilwell Wireless Surveillance) monitoring system seeks to fulfill that promise by allowing daily, remote monitoring of wells in real time at a fraction of the usual cost. It helps operators improve the efficiency of rod-pumped wells controlled by timers. With MEOWS, the operator attaches small wireless flow sensors to a well's flow-line check valves and then can analyze vibration data variations in the well to ascertain oil-flow conditions.

Using MEOWS's off-the-shelf wireless surveillance devices and sensor technology adapted to measuring and transmitting a rod-pumped well's data to a receiver and base-station personal computer, an operator can monitor stripper wells in real time every day at a cost of only about $200 per well.

This system enables an operator to boost oil output mainly by avoiding production losses due to rod-pumping inefficiencies. Savings come from cost reductions for well servicing and testing, electricity, and manual surveillance.

The MEOWS system was field-tested on three wells operated by Vaquero Energy Co., an independent based in Edison, CA. Vaquero operates about 200 wells in the main area of the aging Edison field in Kern County, CA. Edison produces low-quality heavy oil from shallow zones. Contractor Petrolects LLC of San Luis Obispo, CA, installed the MEOWS hardware with durable housings in the often rugged conditions of Kern County's oil fields.

Plans call for also developing an automated pump-off controller (POC) that uses flow indications from the MEOWS sensor for automatic control of the pump jack's beam pump. This would enable an operator to enjoy the benefits of costly, high-tech POC units at a fraction of the cost.

Those benefits in the test wells include an estimated 3-10 percent increase in oil production, a 10 percent decline in electricity costs pegged at $2,000 per month, a 10 percent gain in pump system life, and a reduction in well-servicing costs of about $2,000 per month.

For many of America's independent producers operating at the economic edge, a boost to the bottom line like that can mean the difference between shutting in a well—and perhaps losing those oil reserves forever—or sustaining and perhaps increasing its production.

DOE-funded research points to optimum recovery of Alaska's vast heavy oil resource

Alaska's North Slope boasts the largest oil field ever found in North America—the legendary Prudhoe Bay.

Also linked to the Prudhoe Bay infrastructure is Kuparuk River oil field, the Nation's second-largest oil field by production. And a number of smaller oil fields that still would be considered giants by Lower 48 standards have been developed nearby.

But perhaps the biggest potential source of oil on the North Slope is the less-heralded heavy oil formations overlying the main producing zones at Prudhoe-Kuparuk. As much as 36 billion barrels of original-oil-in-place (OOIP) lies within the Ugnu, West Sak, and Schrader Bluff formations. That surpasses the combined OOIP of Prudhoe and Kuparuk.

Recovering this vast resource, however, has proven a daunting challenge to North Slope operators. These shallow formations' proximity to the subsurface permafrost renders the already low-gravity crudes extremely viscous. North Slope producers have struggled for years to devise an economic plan for their recovery. That goal has become more urgent for America's energy security in recent years because of the production declines that have set in at Prudhoe and Kuparuk. The Trans-Alaska Pipeline System—which carries 20% of the Nation's oil supply, down from a peak of 25% when U.S. oil output itself was much higher—cannot be operated economically if North Slope output falls much further.

North Slope operators have had some success producing some of the less viscous crudes in the West Sak and Schrader Bluff heavy oil formations by injecting into the reservoirs slugs of water alternating with gas (WAG); the gas acts as a solvent to reduce oil viscosity, while the water front helps sweep the reservoir, pushing the crude to producing wells.

DOE-funded research by the University of Houston has developed tools for modeling the optimum WAG flood design. In their final project report, researchers also studied the potential for greatly increased production rates for deploying WAG floods in horizontal wells vs. vertical wells. And the research showed that well productivity for these viscous oil reservoirs can be doubled via electromagnetic heating.

Such efforts could make the difference in keeping America's most prolific oil province on line.

Research helps extend operators' seasonal access to North Slope tundra

Access to federal and state lands in Alaska is the most critical factor in exploration and development of oil and gas in America's Last Frontier.

Because the environmentally sensitive North Slope of Alaska could hold a remaining in-place resource of as much as 50 billion barrels of oil, this issue emerges as crucial to the Nation's energy security.

Without timely development of the previously discovered and the yet-to-be-found oil resources on the North Slope, the U.S. will find its most important oil pipeline, the Trans-Alaska Pipeline System (TAPS), unable to operate economically. In that event, the Nation would lose not only this vital supply link—TAPS ships 20% of U.S. production to market, down from 25% at its peak—but also would lose the ability to recover the slope's remaining oil resources.

Tundra access

Timely E&D on the slope is problematic because of the fragile tundra ecosystem.

Drilling and other industry operations are possible only during a limited window of opportunity, when the tundra is snowy and solid—thus when equipment can be transported without damaging the tundra. This work window was established years ago by consensus among stakeholders but was not established on a scientific basis.

This window of opportunity has decreased from about 200 days in 1996 to 103 days in 2003. This severe time constraint means that North Slope exploration and development operations take twice as long, incurring much higher costs.

The DOE-funded Tundra Travel Model project investigated the potential for a new standard for tundra travel based on scientifically collected data. Researchers found that the tundra was more resistant than expected. They also quantitatively defined the ground hardness required for protecting the tundra in different ecosystems and identified other contributing factors important to enhancing environmental protection during exploration activity. With a better understanding of how the tundra resists disturbance, the State of Alaska found it feasible to advance the opening date for tundra access and maintain or enhance current levels of tundra protection. As a result of this work, state officials opened the eastern coastal area of the North Slope on December 10, 2004. This is the earliest opening since 1995 and is two weeks earlier than last year's start.

Ice roads

Meantime, a primary means of access in the winter operating season, constructing ice roads and pads, also may be threatened because of environmental concerns.

Photo: Anadarko Petroleum

Soft, fat tires are the signature of the rolligon vehicle, designed for transport across the fragile tundra of Alaska's North Slope.

Ice roads and ice pads were first devised as a means of enabling access to the tundra for drilling work while minimizing environmental impact. The ice roads and pads would simply melt in the summer, leaving no footprint. This approach also minimized construction of gravel roads and pads needed to support industry operations.

Construction of ice roads and ice pads usually begins in December or January and can take a month to complete. They typically are suited for traffic through April.

Water must be pumped from North Slope lakes and ponds to build ice roads and pads. Despite its wetlands appearance in summer and total snow cover in the winter, the North Slope is essentially a desert. The region receives minimal rainfall, and virtually all of the snow that provides the ample snowmelt for the slope's water bodies is blown in from the north.

But questions have arisen about the environmental impacts of pumping large vol-

South Central Alaska gas prospects tied to Alaska gas pipeline

The proposed $20 billion Alaskan North Slope natural gas pipeline has been under consideration for over 25 years, and DOE-funded research in South Central Alaska has played an important role in the effort to undertake what some have described as history's biggest construction project.

The research undertaken through NETL's Arctic Energy Office (AEO) focuses on prospects for gas in South Central Alaska and how they relate to the North Slope gas line.

One study, released in summer 2004, offered projections for the future supply of Cook Inlet, AK, natural gas, and identified key gas shortages beginning in 2009 without further exploration and development proceeding in the region south of Anchorage, AK. The Cook Inlet area, which includes Anchorage, is the only area in Alaska where natural gas is widely available and used. This report played a key role in a recent workshop by the Federal Energy Regulatory Commission (FERC) on permitting of the Alaska gas pipeline project.

Meanwhile, another DOE-funded study examined prospects for a possible spur line from the North Slope gas pipeline to South Central Alaska. In December 2004, FERC held hearings on the North Slope gas pipeline and sought input on estimates of current and future natural gas demand in the state, possible offtake points, and tariff structures for transporting North Slope gas to various offtake points in the state.

Brent Sheets, Arctic Energy Office manager, in late March said, "The program is currently working with the utilities and state government to put the study in place to answer these questions. We hope to have this study completed within the next 18-24 months.

"When complete, the Fossil Energy program will have gained significant experience to assist it in carrying out its other duties as they relate to the potential North Slope natural gas pipeline."

umes of water from North Slope lakes and ponds. There have been concerns about this practice's effects on water balances and chemistry and impacts to aquatic organisms.

In fall 2002, a DOE-funded, University of Alaska-Fairbanks-led study kicked off to gather baseline information about the physical, biological, and chemical characteristics of North Slope lakes and ponds in order to address these concerns.

The study's focus is to assess the environmental impacts of pumping more than 15% of the free water from North Slope lakes and ponds.

An ice road, built with water pumped from local lakes and ponds, is shown under construction on Alaska's North Slope.

Thus far, researchers have determined, among other findings, that past water usage has not resulted in measurable adverse impacts for the Kuparuk River oil field area and that some North Slope lakes could handle a 30% volume withdrawal without adverse impacts.

Researchers conducting sampling and measurements of water properties in a tundra pond during the winter.

Now federal and state agencies are considering using watershed and recharge estimates when issuing water withdrawal permits and allowing access to ice chips to enable faster road-building techniques.

As with the Tundra Travel Model, this project holds the promise of lengthening the exploration season on the North Slope.

And it's another demonstration of how relying on sound science can yield consensus among stakeholders in America's most oil-rich and environmentally sensitive state.

Office of Petroleum
E&P SNAPSHOTS

Strategic Center for Natural Gas and Oil (SCNGO) Director **Dr. William F. Lawson** delivered a speech, "Integrity, Reliability, and Security: The Role of Technology," during the plenary session of the 2005 Natural Gas Technologies Conference in Orlando, FL, on Jan. 31. The conference, the Nation's pre-eminent conference on natural gas technologies, is cosponsored by NETL and the Gas Technology Institute. The speech has been posted on the SCNGO Reference Shelf at http://www.netl.doe.gov/scngo/index.html.

On Feb. 23-24, DOE, the Montana and Wyoming U.S. Department of Agriculture Extension Programs, and local conservation districts in the Powder River Basin of Wyoming and Montana sponsored the conference **"Landowner Approaches to Dealing with Coalbed Methane Development: The Art of Comprise."** The conference was held in both Sheridan, WY, and Forsyth, MT. Its purpose was to educate stakeholders in areas of current or potential coalbed methane development about negotiation and conflict-resolution strategies.

NETL Tulsa staff participated in the **Federal Leadership Forum** Core Team Conference Call on March 3. Major issues are air quality and National Environmental Policy Act analyses. A work group is to review and evaluate ongoing efforts and protocols and summarize the status of air quality management. The group also will identify most overarching issues with respect to managing air quality in the context of high levels of oil and gas development. It will review inconsistencies and redundancies among oil and gas NEPA analyses, along with poor communications among agencies, that could lead to prolonged and overly expensive analyses that may be vulnerable to legal challenge. The next Federal Leadership Forum meeting is planned for June.

Projects managed by NETL's **Office of Petroleum** warranted significant coverage in the Oil & Gas Journal (OGJ), the leading international oil and gas magazine of news and technology. The NETL-funded study "Downhole Separation Technology Performance: Relationship to Geologic Conditions" was highlighted in an article in the Dec. 20, 2004, issue of OGJ. In its Feb. 21, 2005, special report on Downhole Technology, OGJ published a 5-page Point of View feature article on NETL's Microhole Initiative based on an interview conducted with Roy Long, Office of Petroleum E&P Technology Manager.

DOE, the Environmental Protection Agency, and the Society of Petroleum Engineers cosponsored the **Exploration & Production Environmental Conference** March 7-9 in Galveston, TX. The conference featured best practices employed in petroleum exploration and production to manage, minimize, treat and dispose of exploration and production by-products. Information was presented on source reduction, substitution of less toxic materials, soil and groundwater remediation, naturally occurring radioactive materials, environmental training and education, and innovative technologies.

Test drilling began March 30 at the **GTI Catoosa Drilling Test Site** in Catoosa, OK, with a new high-power turbodrill and thermally stable polycrystalline (TSP) bit as part of NETL's Microhole Initiative. The project entails developing a turbodrill/drill bit system capable of drilling 3½-inch boreholes with existing coiled tubing technology. The test was designed to help define and analyze performance of the turbodrill and special drill bits and provide baseline comparison data for a newly designed, higher-torque turbodrill and TSP drill bit.

Michigan Technological University has published results of imaging techniques based on four DOE projects in the April 2005 AAPG Bulletin. "Well-log tomography and 3-D imaging of core and log-curve amplitudes in a Niagaran reef, Belle River Mills field, St. Clair County, Michigan, United States," by Albert Wylie and James Wood, discusses recently developed techniques for visualization of carbonate reservoirs. The technique generates sub-horizontal slices through log curves based on core permeability, core porosity and gamma-ray logs from Silurian reefs in the Michigan Basin. The new log-curve amplitude slicing and 3D imaging allows representation of dolomitized and diagenetic features of the carbonate facies. Interpretations use trends and patterns to improve sequence-stratigraphic models of the Niagaran pinnacle reef fields. The value of the new tools will be in the enhanced design and placement of vertical and horizontal wellbores in the pinnacle reefs.

Calendar of Events/2005

Apr. 17-19
SPE, *Production and Operations Symposium,* Oklahoma City, OK. Contact: www.spe.org.

Apr. 20-21
IDAC/SPE, *Managed Pressure Drilling Conference and Exhibition,* San Antonio. Contact: www.spe.org.

Apr. 27-29
SPE Gulf Coast Section, *2005 Electric Submersible Pumps Workshop,* The Woodlands, TX. Contact: www.spe.org.

May 2-5
SPE, *Offshore Technology Conference,* Houston, TX. Contact: www.otcnet.org.

May 15-17
IOGCC, *2005 Midyear Meeting,* Anchorage, AK. http://www.iogcc.state.ok.us.

May 19
IADC, *Drilling Onshore America Conference & Exhibition,* Houston, TX. Contact: www.iadc.org.

May 24-25
IADC, *Drilling Engineering Association Workshop,* Galveston, TX. Contact: www.iadc.org.

Jun. TBD
IADC, *World Drilling 2005,* Rome, Italy. Contact: www.iadc.org.

Jun. 19-22
AAPG, *2005 Annual Convention Exploring Energy Systems,* Calgary, Alberta, Canada. Contact: www.aapg.org.

Jun. 19-24
SPE, *Directional Drilling and Complex Well Architecture–Forum,* Broomfield, CO. Contact: www.spe.org.

Jun. 19-24
SPE, *Technology Development–Who Pays and Who Plays? – Forum,* Broomfield, CO. Contact: www.spe.org.

Jun. 26-Jul. 1
SPE, *Getting Deeper and Deeper–The Future of Deepwater Exploration, Drilling, and Production Operations–Forum,* Broomfield, CO. Contact: www.spe.org.

Jun. 26-Jul. 1
SPE, *E&P Phone Home–Automation, Measurement, and Remote Control–Forum,* Broomfield, CO. Contact: www.spe.org.

Sep. 18-20
IOGCC, *2005 Annual Meeting,* Jackson Hole, WY. Contact: www.iogcc.state.ok.us.

Sep. 25-27
AAPG, *Gulf Coast Association of Geological Societies 55th Annual Convention,* Jackson Hole, WY. Contact: www.gcgas2005.com.

Nov. 6-11
SEG, *International Exposition & 75th Annual Meeting,* Houston, TX. Contact: meetings@seg.org.

Nov. 30-Dec. 1
IADC, *Drilling Gulf of Mexico Conference & Exhibition,* Houston, TX. Contact: www.iadc.org.

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