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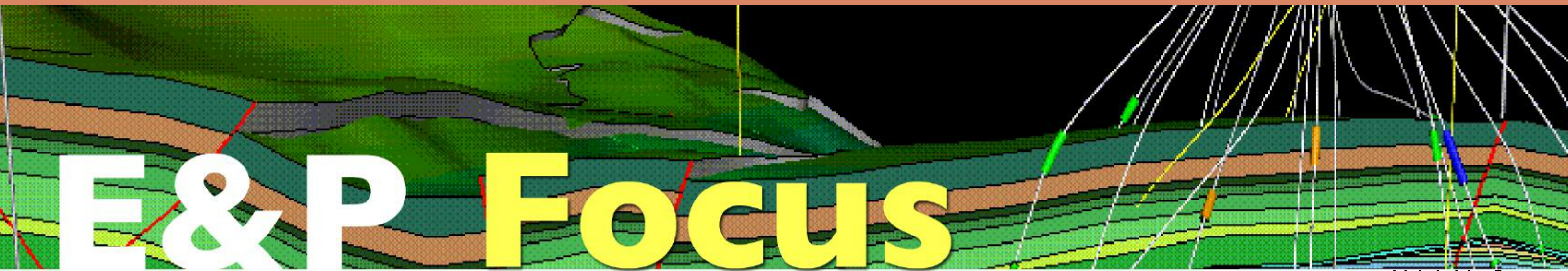

Vol. 1, No. 3

DOE research helping VSP fulfill promise of 'designer seismic'

U.S. Department of Energy-funded research is pushing vertical seismic profiling (VSP) technology closer to fulfilling its promise as "designer seismic" for America's oil and gas operators.

VSP, which entails placing seismic signal receivers in boreholes and sources at the surface, allows the recording of much higher frequencies and higher-resolution images than does surface seismic, which has both receivers and sources at the surface. The result is an enhanced picture of the subsurface that helps operators reduce drilling risk and optimize oil and gas recovery.

While VSP and other types of borehole seismology have been around for decades, its high costs, data processing hurdles, and industry's inherent reluctance to adopt new technology have limited its use.

However, research projects managed by DOE's National Energy Technology Laboratory are advancing the science of VSP data acquisition and processing, demonstrating a broader applicability for VSP, and reducing the costs of this promising technology.

Borehole seismology

There are three main reasons why borehole seismic data has superior resolution over surface seismic methods:

• Borehole seismic avoids the near-surface layer of weathered rocks and soil. The weathered layer weakens the surface seismic signal twice: when being sent by the source and when being received by the geophones. Eliminating one or both trips through the weathered zone allows more high-frequency signals to be received. The frequency content of borehole seismic data is typically more than double that of surface seismic data.

• The downhole recording environment is very quiet. The sensitive geophones are not affected by oilfield pumps, generators, vehicles, and other surface noises.

• The instruments are closer to the targets being imaged.

VSP is just one of several borehole seismic methods, which are distinguished mainly by their source/receiver geometry:

• **Single-well seismology** deploys both the source and the receivers in the same borehole.

• **Reverse VSP** transmits seismic energy from a seismic source in a borehole to geophones on the surface.

• **Cross-well seismic** entails placing the energy sources and receivers in two separate boreholes. The images created are in a two-dimensional plane between the source and receiver wells. The low-energy piezo-electric sources needed for a borehole source limits the quality of the image.

"With operators now taking high-quality 3-D images for granted, 2-D VSP doesn't have the appeal it might have had otherwise…The barrier to 3-D VSP is cost, not technology. Yet the benefits are inarguable."

— Dr. William F. Lawson, Director, Strategic Center for Natural Gas and Oil

VSP advantages

A key advantage of VSP is that borehole seismic data typically achieve a much higher signal-to-noise ratio than do surface seismic data because of the quiet borehole environment and the strong sensor coupling to the borehole wall. Surface geophones, on the other hand, are generally poorly coupled in weathered rock and exposed to environmental noise at the surface.

The use of multicomponent seismic data has significantly increased the resolution of subsurface images and increased the number of reservoir properties that can be distinguished. Seismic signals include 3 components, or wave types: compressional, or P, waves; shear, or S, waves; and converted waves, or combined S and P waves. VSP is particularly well-suited to collecting high-quality multi-component data because of its ability to strongly couple geophones to rocks. Although S waves are recorded from surface seismic, they almost always contain only low frequencies, allowing only large-scale delineation of reservoir properties.

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The benefits of high-resolution reservoir imaging from multicomponent VSP data are that reservoir characteristics such as geometry, lithology, pore fluids, and fractures can be delineated. The improved understanding of reservoir properties lowers the economic risk of field development activities by guiding optimum infill well locations and well re-entries. Sharp reservoir images provide information for optimum placement of production and injection wells to increase recovery efficiencies.

The information gleaned from VSP also assists in profitable operation of marginal fields and enables identification and production of bypassed, or “stranded,” oil and gas that may not be seen with conventional 3-D surface seismic data.

VSP history

The roots of borehole seismology can be traced to R.A. Fessenden’s patent of 1917, apparently the first documented seismic application entailing buried seismic sources and geophones, according to the University of Texas’ Dr. Bob Hardage, writing in the September 2001 CSEG Recorder.

However, even though the value of VSP was known for years, American geophysicists largely ignored its potential, using boreholes only for velocity measurements such as in check-shot surveys, Hardage wrote. A much more aggressive approach was undertaken by geophysicists in the Soviet Union during the 1960s and 1970s, and some of this knowledge was shared with American geoscientists in the late 1970s.

By the 1980s, a global surge of interest had developed in the potential for using VSP as a tool for hydrocarbon exploration in its own right, not merely for velocity measurements, according to Hardage. Now there are new technology thresholds for VSP imaging to cross, such as paralleling the industry’s overall transition from 2-D seismic to 3-D seismic. Although the technical feasibility and value of VSP have been demonstrated thoroughly over the years, says Dr. William F. Lawson, Director of NETL’s Strategic Center for Natural Gas and Oil (SCNGO), VSP has yet to cross the bridge from 2-D to 3-D.

With operators now taking high-quality 3-D images for granted, 2-D VSP doesn’t have the appeal it might have had otherwise, Lawson contends, adding that the barrier to 3-D VPS is cost, not technology.

“Yet the benefits are inarguable,” Lawson noted. “Multicomponent VSP data is the most reliable way to underpin the rigor of correspondence between stratigraphic depth and P and S image times.”

With the help of DOE funding, some progress has been made on the VSP front. Cost reductions have been realized by shrinkage in equipment size, and recent advances in software programming have enabled large, complex data sets to be processed.

DOE VSP efforts

NETL is managing a number of DOE-funded VSP technology projects in the Oil Program that address both data acquisition hardware and seismic data processing software.

DOE’s Advanced Diagnostics and Imaging Systems program targets technology development in seismic and other imaging technologies. A number of these projects are on the forefront of VSP technology development and include such areas as miniature geophones; time-lapse reservoir monitoring with small, portable seismic acquisition systems; multicomponent seismic data processing software; and large downhole arrays.

Perhaps the most promising effort of all on the VSP front is DOE’s Microhole Technology (MHT) Initiative, which uses ultrasmall-diameter holes for exploration and data acquisition (see related article, pp. 6-7). Such low-cost, environmentally friendly boreholes can be dedicated to reservoir monitoring with VSP that allows optimum placement of data collection locations without interfering with operational activities. The idea is that microhole technology’s reduced costs will spur producers to economically monitor their reservoirs permanently with VSP without interrupting production. For the first time, a geophysicist can 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 when and where needed rather than where production or injection wells have been drilled. Hence the label “designer seismic.”

The following sections cover a few selected areas of advancement in VSP technology through DOE funding.

Miniature geophones

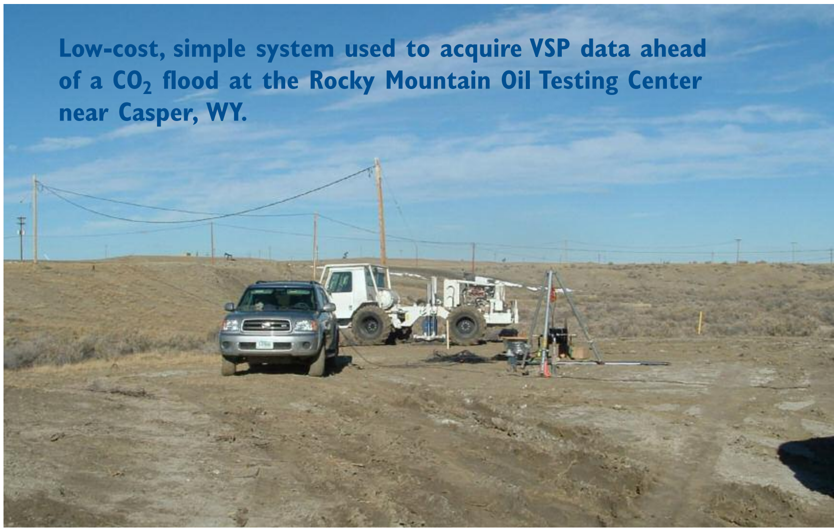
Los Alamos National Laboratory, supported by the DOE, successfully miniaturized downhole geophones that are 0.395 inches in diameter. Subsequent work using micromachined accelerometers developed a class of sensors called microelectromechanical systems (MEMS). The geophones and MEMS accelerometers perform as well as, if not better than, conventional geophones. Once the new tools’ design is moved to fabrication, they can be manufactured at significantly lower costs than conventional borehole logging tools and instrumentation packages.

These geophones can be packaged so that they can be deployed in the casing annulus of most wells or in small-diameter production tubing. Such deployment options allow VSP data to be acquired in producing wells without pulling tubing and without interrupting production while collecting seismic data.

The microinstruments were developed, along with a suite of 7/8-inch diameter logging tools, in concert with the MHT Initiative.

4-D seismic and VSP

Time-lapse, or 4D, seismic entails repeated seismic surveys over the same area at different times so that changes in reservoir properties can be observed over time. Time-lapse reservoir monitoring can be used to “see” the front of injected liquids or gas



Low-cost, simple system used to acquire VSP data ahead of a CO_2 flood at the Rocky Mountain Oil Testing Center near Casper, WY.

during secondary and tertiary oil recovery as it sweeps across the reservoir. It also can be used to image changes in reservoir characteristics as the reservoir is being produced.

The quality of time-lapse reservoir monitoring markedly improves with VSP, which has the advantages of:

- Increased frequency signal range that improves vertical and lateral resolution, allowing reservoir examination in greater detail, both statically and dynamically.
- Improved signal-to-noise ratio that permits the measurement and quantification of time-lapse changes in the reservoir with a high degree of confidence.

Lawrence Berkeley National Laboratory is preparing to establish the technical feasibility of a time-lapse VSP survey of a CO_2 flood via microhole emplacement at the Rocky Mountain Oil Testing Center near Casper, WY.

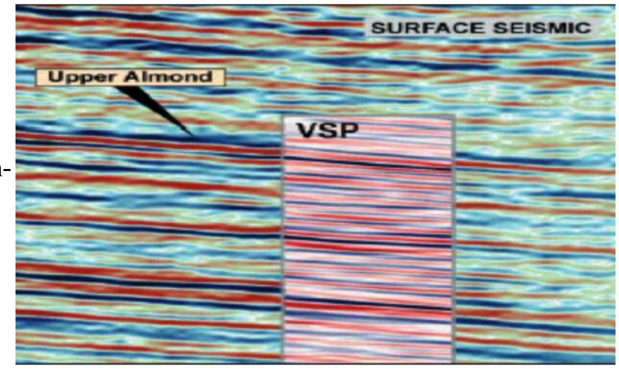
So far, four microholes that will be dedicated to monitoring the CO_2 flood have been drilled with a small, highly portable coiled tubing drilling rig designed by Los Alamos National Laboratory. VSP surveys are being conducted to obtain baseline data in preparation for the upcoming CO_2 flood and to test the deployment and use of sensors in microholes.

The acquisition system used was low-cost and simple—comprising a vehicle used as a "doghouse," a small vibrator truck for the source, a 20-geophone string that was hand-deployed by one person in 1 hour, and a small tripod to support the geophone string. Typically, a workover rig and many more personnel are needed for a VSP survey. In addition to the easy deployment, the seismic data collected were of excellent quality, with a high signal-to-noise ratio.

Multicomponent processing software

Technology development of VSP data processing and interpretation software has lagged behind the advances in data acquisition hardware. Adequate 3-D multicomponent display, processing, and interpretation capabilities are needed to maximize the use of large multicomponent data sets.

Paulsson Geophysical, with DOE funding, is developing a full-featured, fast, interactive 3-D multicomponent processing and interpretation tool for VSP data. Existing pieces of processing software are being combined with novel display capabilities



Comparison of resolution for VSP vs. surface seismic.

and a framework to perform complex processing tasks interwoven with the analysis and interpretation of 3-D multicomponent VSP data. The software both processes and interprets VSP data using a 3-D graphical user interface to drive the necessary processing and imaging algorithms. The software allows the use of auxiliary information, including well logs, formation tops, seismic ray path computations, and velocity models. The auxiliary information is combined with data and processing results to enable interactive model changes and quality control. The software runs on Linux as well as Windows XP operating systems.

The product of this research will be a commercially available, multicomponent 3-D borehole seismic software tool that readily can be used for field development and production with enough detail and coverage to have a significant impact on reservoir management.

Large downhole seismic arrays

A recently developed approach to VSP data acquisition is to use large borehole seismic arrays with hundreds of 3-component (3-C) geophones and thousands of surface source points. Paulsson Geophysical, with DOE funding, has pioneered reliable large-array 3-D borehole seismic acquisition systems and has shown that highly accurate multicomponent data can be recorded. In this project, 5 strings, consisting of 80 3-C geophones each, will be deployed in 5 wells. This results in the first-ever 400-level recording system.

Paulsson's aforementioned processing software is designed to handle the massive amounts of data generated by these large downhole seismic arrays.

In the past, the number of borehole arrays has been limited by the 7-conductor wireline typically used to deploy geophones downhole. These wires have too few channels to economically record the large data sets necessary for 3-D seismic imaging. Paulsson developed a proprietary method of deploying 3-C geophone sensors attached to downhole tubing and providing a dedicated channel for each sensor component at each receiver level. Now 3-D borehole seismic imaging is a viable and economic option, as up to 1,200 channels can be deployed in one well.

The reservoir images created from large downhole multi-component seismic arrays can have tenfold the resolution of surface seismic images. For example, where surface seismic can "see" only rock layers that are 40 feet thick or more, large downhole arrays can image layers 4 feet thick. This capability corresponds to a 10-30% increase in enhanced recovery of oil and gas from complex reservoirs in existing fields, according to Lawson.

The 3-D borehole seismic data also allows detailed structural imaging of the reservoir and can lead to detailed petrophysical determinations, such as detecting variations in lithology, porosity, pore fluid content, or bulk rock properties.

VSP potential

Realizing VSP's potential rests on finding low-cost solutions to its deployment. Using MEMS technology and very low-cost drilling such as coiled tubing microbores, microinstrumentation holes can cost from a tenth to a fourth that of conventional holes. As the technology advances, low-cost placement of VSP can be used to:

- Minimize exploration risk by better imaging of fault blocks, bypassed compartments, and deeper zones.
- Accelerate the use of 4-D seismic.
- Support industry's move to four-component arrays.
- Render affordable long-term—even permanent—imaging of reservoir fluids for improved oil recovery projects without disrupting production.

In short, making affordable a better "picture" of the subsurface is within the U.S. oil and gas industry's grasp—and the result could be billions of barrels of additional oil for the Nation's energy and economic security.

DOE funds project to futher develop Russian oilfield technology in America

The Department of Energy has marked another key milestone in its longstanding effort to create peaceful commercial opportunities for former Soviet Union (FSU) weapons scientists, engineers, and technicians through a variety of programs.

DOE recently announced the award of funding for two innovative projects, incorporating Russian oil field technology, that are designed to dramatically boost recovery and production of bypassed oil resources in mature, declining American oil fields.

The funds will be awarded as part of a cost-sharing arrangement under DOE's Russian Technology Program, a technology development and demonstration program started in 1994. Since then, U.S. industry has joined with DOE to form partnerships with institutes and private companies in Russia, Ukraine, and Kazakhstan to bring new technologies to the world market.

In 2004, Russia was the world's largest producer of both oil and natural gas. Until shortly after the collapse of the Soviet Union, there was no transfer of technology between Western oil and gas companies and those in the Soviet oil sector. As Russia and other nations in the FSU have benefited from the influx of Western oilfield technologies, Russia's own innovations also have begun to emerge in recent years.

While challenges remain in Russia and elsewhere in the FSU, there is a wealth of experience and resources available to assist interested U.S. companies to expand their markets, enhance their capabilities, and create profitable new partnerships.

Helping promote further development of Russian oilfield technology in America helps bolster the Nation's energy security by boosting domestic energy production.

Project details

The DOE partners are New Mexico Institute of Mining and Technology, Socorro, NM, and More Oil Inc., a small company based in Westland, MI. Both projects focus on improved oil recovery (IOR) technologies and entail completing research and development of promising technologies initially developed in Russia, with an eye to commercialization in the U.S.

At New Mexico Tech, work will center on a novel approach to making CO_2 flooding less costly and more effective than a conventional CO_2 flood. What sets the Russian technology apart from existing Western technologies is that the CO_2 is injected as part of a dense liquid, rather than having to compress the CO_2—at great cost—in order to inject it. While CO_2 flooding is the fastest-growing method for enhancing oil recovery in the U.S., its high costs limit it to the biggest reservoirs. Because the CO_2 is released downhole, this cost-effective approach could make many smaller mature U.S. oil fields candidates for CO_2 IOR.

Another part of the New Mexico Tech project entails development of a proprietary surfactant foam to help reservoir sweep in a CO_2 flood. The Russian surfactant forms foam when the CO_2 is generated in the reservoir. The two technologies initially were developed by the Institute of Geology and Development of Fossil Fuels in Moscow, Russia. DOE will fund $569,000 of the 24-month, $709,000 project.

"DOE is encouraging U.S. companies to cultivate and develop business-to-business partnerships with Russian technology organizations."

A two-pronged IOR approach also is employed in the More Oil project. The Michigan company will seek to commercialize a chemical supply system and bore-hole generator developed in Ekaterinburg, Russia. Again, a Russian technology "tweaks" common industry practice in an innovative way. Hydraulic fracturing to stimulate oil well production, while effective, can total a fifth of a producing well's cost. In situ combustion as a form of well stimulation is much less costly than hydraulic fracturing but often is ineffective because of downhole heat losses.

The More Oil project combines both approaches by combining the heating of oil via chemical reaction downhole with a fracturing process. A special apparatus is used to increase the working volume of high-temperature, foaming reagents to induce fractures while heating the oil within the reservoir rock. If successful in demonstrating that a chemical generator can heat the pay zone on demand while introducing the power of hydraulic fracturing, this approach could prove to be a "game-changing" technology. DOE will fund $667,000 of the 12-month, $842,000 project.

Program details

The two projects were selected through a competitive solicitation by DOE's Office of Fossil Energy (FE) under the Russian Technology Program. Under the solicitation, applicants were required to be American companies, and the technology had to originate in Russia. Thirteen proposals representing 12 applicants from 7 states were received. FE's National Energy Technology Laboratory will oversee the projects. Funds for the projects will come out of the nearly $2 million that Congress appropriated for the Russian Technology Program. About 35% of the program funds is being used to conduct a 30-month assessment of the oil and gas resources in the Russian Arctic by the U.S. Geological Survey.

New arctic well cement offers safety, environmental benefits

Annular gas migration has long bedeviled the oil and gas industry.

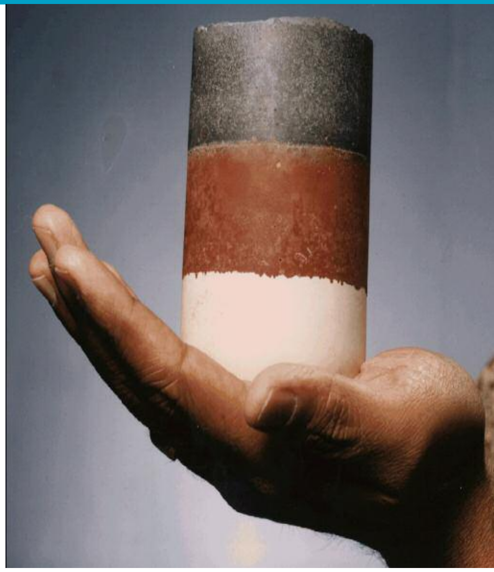
Failure to control the migration of gas in the well annulus can lead to gas channeling that could result in loss of reserves, pollution, even a catastrophic blowout. Gas migration problems often stem from well cementing failures. Efforts to control gas migration usually entail a costly cement squeeze job.

Nowhere is this a bigger concern than on Alaska's North Slope, where operators must take special care not to disturb permafrost soils during production and wellbore transport of oil and gas. In arctic regions of the state, such as the North Slope, the soil is frozen to at least 1,500 feet year-round. In order to protect soil integrity, Alaskan regulations for casing and cementing require that the operator protect against thaw subsidence and freeze-back within a permafrost region. That's why it's especially critical to use cements with the right insulating and binding qualities needed to keep the permafrost soils frozen and undisturbed during oil and gas drilling and production operations.

Under DOE's 5-year noncompetitive cooperative agreement with the University of Alaska-Fairbanks (UAF) in Fairbanks, AK, progress is being made on a phosphate-bonded ceramic borehole cement, created by Argonne National Laboratory (ANL), that holds promise as a suitable insulating and binding cement for permafrost regions.

In addition to protecting permafrost soils and improving the wellbore transport of oil and gas, the light-weight cement will be more cost-effective for North Slope operators to use and transport to remote arctic locations than conventional cements.

What's more, this innovative material holds great promise for the future development of two massive untapped North Slope resources: shallow, viscous oil and methane hydrates. The total North Slope heavy oil resource is estimated at 36 billion barrels of original-oil-in-place—more than that of giant North Slope oilfields Prudhoe Bay and Kuparuk combined. Alaska's arctic methane hydrate resource is pegged at 590 trillion cubic feet of natural gas—more than triple America's current total proved gas reserves.



Sample of ceramicrete, a novel insulating well cement for use in the arctic permafrost regions.

Project details

UAF is working with this new cement—dubbed "ceramicrete," similar to what ANL designed to stabilize radioactive waste—in order to develop a suitable composition to meet operators' needs in permafrost regions. The intent is to develop a new cement that has superior strength while still having very low permeability and thermal conductivity. The goal is to design a cement for use in ultra-cold climates that can set at subzero temperatures but has a low formation heat to avoid thawing the permafrost.

The first year of work on the project, managed by the National Energy Technology Laboratory, has been completed. Project performers have identified the correct mix of material to produce the properties required for downhole pumping on the North Slope while still meeting tensile strength requirements. Testing is under way to ascertain the material's reaction to cycles of thawing and freezing and if the material will set with temperatures as low as -40 degrees F.

Next up are plans to collaborate with industry partners and conduct field tests under arctic conditions at a site in Alaska. Then the researchers will test the ceramicrete formulas for other infrastructure applications in the state, such as pipeline supports and other civil engineering applications.

Office of Petroleum E&P SNAPSHOTS

NETL staff attended four public scoping meetings the week of Aug. 22, in southeastern Montana. The meetings were in response to the U.S. District Court ordering BLM to conduct a review of a phased-development alternative to the original Environmental Impact Statement (EIS) governing **coalbed natural gas development and production in the Powder River and Billings, MT, areas**. BLM is now preparing a supplemental EIS, slated for completion in December 2006.

NETL staff attended the Operator Round Table meeting at the Kiamichi Technology Center in Poteau, OK, on Aug. 17. The meeting was sponsored by the **Oklahoma Commission on Marginally Producing Oil and Gas Wells**. The theme of the meeting was motor controls and optimizing operation of wells in order to save fuel and lower expenses incurred by rod jobs, motor replacements, downhole pump replacements, tubing wear, etc.

On Aug. 10, NETL representatives attended a celebration of the 1-year anniversary of the **Tallgrass Prairie Ecological Research Station**. In 2002, the University of Tulsa was awarded funding from NETL to conduct research pertaining to soil ecosystem restoration. The objective was to address an appropriate response to spills of crude oil and produced water brine. The project later garnered added funding from EPA and API, and the research station was completed in May 2004.

Stanford University, a world leader in heavy oil research, will present a technical paper related to heavy oil production at the 2005 SPE International Thermal Operations and Heavy Oil Symposium in Calgary, AB, Nov. 1-3. The paper, a result of NETL project support, is entitled **"An Adaptive In-Situ Combustion Model—Multiscale Process Coupling by Fractional Stepping"** and will be presented at a symposium session on simulation. Stanford is currently working on providing an accurate in-situ combustion 3-D numerical simulator that incorporates adaptive mesh refinement and parallelization.

DOE's Microhole Initiative reaches next stage: integration of technologies

The Department of Energy's Microhole Technology (MHT) Initiative has advanced to the next stage of its evolution: integrating the suite of technologies that could change the way America's oil and gas wells are drilled.

The game-changing MHT Initiative holds a heady promise for the Nation's oil and gas operators: the prospect of thousands of new infill wells drilled at low cost and with minimal environmental impact.

DOE's MHT Initiative entails developing and commercializing a suite of technologies related to drilling wells with ultrasmall diameters and deploying downhole microinstruments specially designed for such small holes. This gives operators the opportunity to use smaller, easily transportable coiled tubing (CT) drilling rigs to dramatically cut the costs and risks of drilling shallow- and moderate-depth holes for exploration, field development, long-term subsurface monitoring, and production. These ultrasmall-diameter wells also carry significant environmental benefits by shrinking the "footprint" of drilling operations and reducing related waste volumes.

DOE's National Energy Technology Laboratory, which manages the MHT projects, launched two solicitation rounds in 2004-2005. The first solicitation, announced in June 2004 and involving six projects valued at nearly $5.2 million, focused on field demonstrations and development of technologies needed to deploy CT microhole drilling in the field. The second round, announced in January 2005 and involving 10 projects valued at almost $14.5 million, emphasized implementation of more field demonstration projects in addition to technology development projects (see related articles in E&P Focus, 1Q2005, pp. 1-3).

Microhole integration

In the latest milestone, NETL held back-to-back meetings in Tulsa, OK, and in Houston, TX, Aug. 16-17, to update the status of Microhole II projects and to kick off the process of microhole technology integration, respectively.

The Petroleum Technology Transfer Council, also funded by DOE, was given the task of facilitating several such meetings in the coming year that will bring project investigators and managers together with industry in order confirm compatible pathways on technology development. The next meeting is scheduled for Nov. 16, 2005, in Houston.

At the Aug. 17 meeting in Houston, Roy Long, NETL's Oil E&P Technology Manager, noted, "Industry is moving forward simultaneously on multiple fronts to develop and test rigs and many system components to make microhole wellbores a widely adopted reality."

MHT II update

MHT II awardees gave progress reports on their projects at both meetings:

• Jeff Spray of Confluent Filtration Systems LLC (CFS), Houston, reported on his firm's two projects. One is CFEX, a revolutionary elastic-phase, self-expanding tubular technology, which is entering its final design phase. The idea is to bring expandable tubulars technology to microhole sizes. CFS's other project involves the development of self-expanding sandscreens designed to mitigate the problem of formation plugging that worsens with ultrasmall-diameter monobores. The target is a screen designed for <150 micron particle retention and a 2,000 psi collapse threshold.

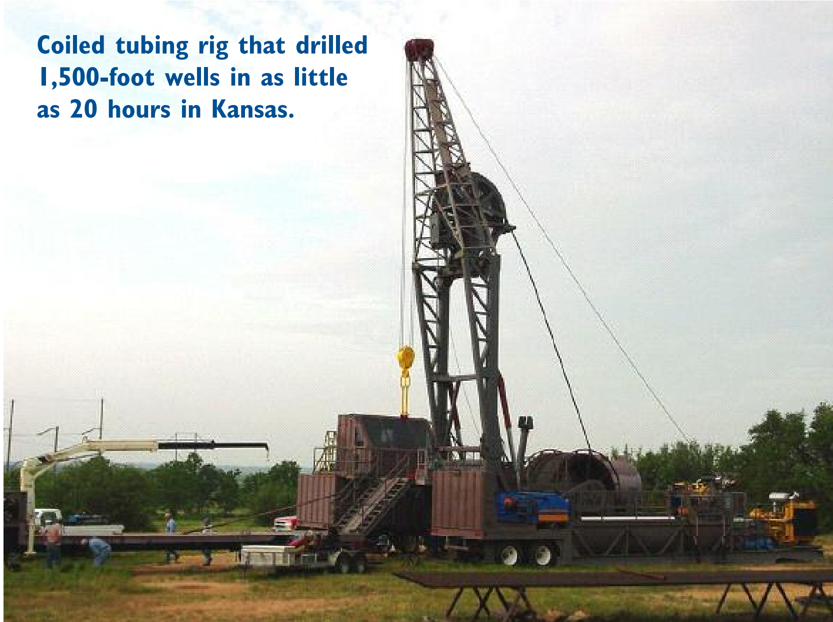
• Jack Kolle of Tempress Technologies, Kent, WA, outlined progress on his company's efforts to develop a small, mechanically assisted, high-pressure waterjet drilling tool. With an inline gas separator and downhole intensifier, the tool would boost downhole drilling pressure to 10,000 psi, essentially allowing CT drilling with very low or no thrust and torque. The project is in its first phase, with a preliminary design completed and Tempress seeking operating parameters from other MHT technologies to proceed with building a prototype.

• Ed Smalley of CTES LP, Conroe, TX, cited significant savings with using friction-reduction technology vs. a downhole tractor in his firm's project to develop a robust, low-cost system for mitigating friction in microhole CT drilling. CTES has completed its model and is getting ready to build test facilities, with an eye to having the first test results by the end of September.

• Robert Radtke of Technology International Inc. (TII), Kingwood, TX, said that successful field tests of a new high-power turbodrill designed for CT drilling of small-diameter wells provided a good benchmark for proceeding with manufacturing and testing prototype tools. TII tested the turbodrill in a 2⅞-inch borehole with high RPMs and low weight on bit (WOB) at the GTI Catoosa Test Facility at Catoosa, OK. The company cited results indicating a 13% efficiency gain and a 30% reduction in the length of the tool's power section. The company also is designing a novel drillbit with high-temperature cutters at 1,100-2,200 RPMs that can drill hard and abrasive rock in 3½-inch boreholes.

• Don Macune of Ultima Labs Inc., Houston, reported progress on his firm's project to combine existing technologies for measurement-while-drilling (MWD) and logging-while-drilling (LWD) into an integrated, low-cost system allied with CT drilling of small-diameter wells. Detailed design was set to begin by this October, with two prototypes to be ready for field testing by first quarter 2007.

• John Macpherson of Baker Hughes Inteq

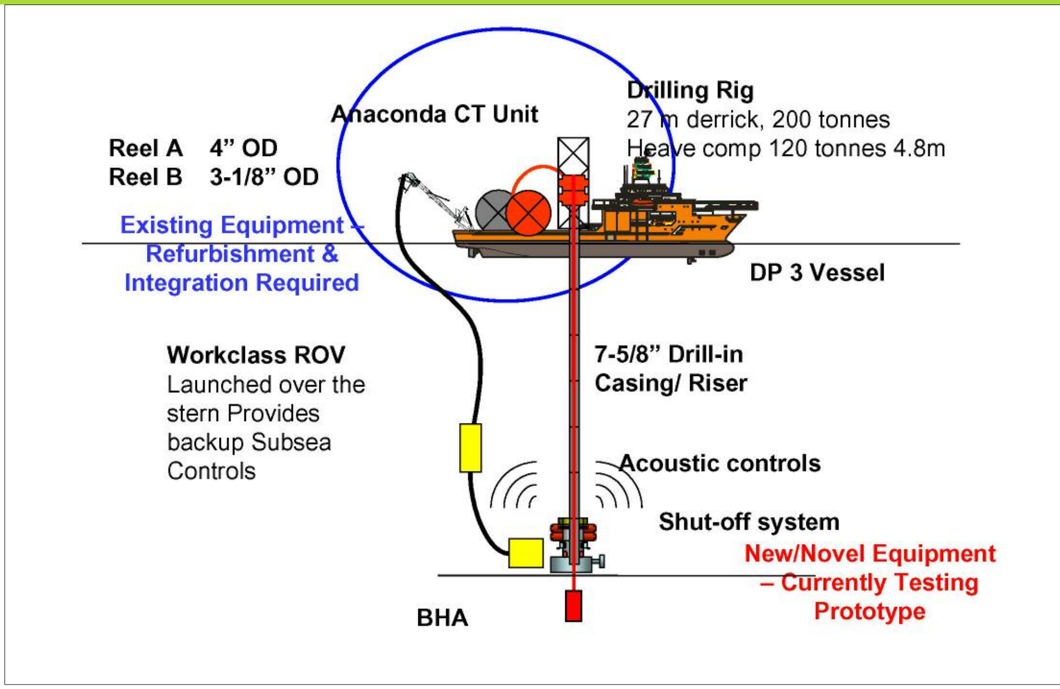


Coiled tubing rig that drilled 1,500-foot wells in as little as 20 hours in Kansas.

(BHI), Houston, outlined progress on his company's efforts to tackle the problem of insufficient steering accuracy and control in microhole CT drilling. BHI is developing a wireless steering-while-drilling tool along with a 2⅜-inch bidirectional power and communications module—based on mud pulse telemetry instead of e-line—that is suitable for ultrasmall-diameter boreholes. Plans call for assembling and lab-testing prototypes by second quarter 2006, beginning field testing in early third quarter 2006, and then completing performance reviews and project documentation by late third quarter 2006.

• Kent Perry of Gas Technology Institute (GTI), Des Plaines, IL, gave status reports on two GTI projects under the MHT Initiative. One involves a means to compensate for the limitations of CT drilling with regard to torque and WOB while still remaining cost-effective. GTI is developing a counter-rotating tandem-motor drilling system suitable for CT drilling of 3½-inch boreholes that features a high rate of penetration, low WOB, and low reactive torque. GTI has completed preliminary design of a 2¼-inch left-hand pilot bit and a 3½-inch right-hand reamer. Fabrication is set to begin this winter, with testing at the GTI Catoosa facility slated for next spring. The other GTI project involves a field demonstration of a next-generation microhole CT drilling rig. The MOXIE experimental rig was fabricated by Dallas, TX-based Coiled Tubing Solutions specifically for CT microhole drilling to 5,000 feet. GTI will assess field results and lead a technology transfer program. Working for Dallas-based operator Rosewood Resources Inc., the CT rig drilled 10,000 feet of 4¾-inch hole in Western Kansas, for a total of 8 microbore wells. The rig drilled 1,500-foot Niobrara wells in as little as 20 hours, at a 30% cost savings vs. conventional drilling, Perry said. In all, the CT rig drilled over 110 wells in Colorado and Kansas. Long described the project as representing the "'Wal-Mart' of low-cost wells and low environmental impacts."

• Colin Leach of Geoprober Drilling, Houston, updated his firm's project to use drill three wells with an innovative composite CT drilling system. It would confirm the capability to drill low-cost, shallow slim/microhole exploration wells in as much as 10,000 feet of water. Plans call for a shallow onshore well to test the Anaconda composite-coil equipment, followed by a subsea demonstration in shallow waters and a deepwater demonstration well. Leach said the system's prototype downhole assembly has been built and was scheduled to be tested at the end of August. He projected cost savings vs. a conventional deepwater drilling system at 59% and added, "The gap is getting wider."



Geoprober's composite-coil drilling system layout

MHT I update

Joining the MHT II awardees in Houston were project participants from the MHT I round, who gave updates on their year-old projects.

• Bart Patton of Schlumberger, Houston, reported that his company's built-for-purpose CT rig could be ready by late 2006.

• Bruce Moore of Western Well Tool, Houston, said his firm will continue developing its microhole downhole drilling tractor for the larger-size microboreholes of 3⅝-inch minimum diameter (changed from original specifications of 3½-inch diameter) in order to accelerate near-term testing and commercialization in Alaska.

• Macpherson said that BHI will continue to develop an MWD/LWD steering system for hole sizes between 2¾ inches and 3½ inches to include a capability to pass through a 2.7-inch diameter restriction. The larger borehole sizes will be supported by BHI's existing CoilTrack bottomhole assembly.

• Ken Oglesby of Impact Technologies LLC, Tulsa, OK, reported that Phase I had been completed of the project (undertaken with Bandera Petroleum LLC, also of Tulsa) to develop an advanced mud system for microhole CT drilling. Results include setting specifications for components such as pumps to convey drilling fluids downhole, a means to process returned well fluids, and a method to drill a hole in rock with an abrasive-laden fluid.

• Larry Stolarczyk of Stolar Research Corp., Raton, NM, updated his firm's progress on testing two advanced technologies for CT drilling: a digital signal processing-based radar system to conduct real-time MWD for CT guidance and navigation and a two-way inductive radio for transmitting CT drilling data. Both systems have been fabricated, and the project is nearing completion.

Although not one of the NETL MHT projects, BP's CT drilling experiences in Alaska and plans for using CT drilling for a program of sidetracks to revitalize mature gas fields in the Anadarko basin were the subject of a presentation by Joe Melvan of Orbis Engineering Inc.

More details on the projects can be found at www.netl.gov; copies of the meeting presentations are posted at http://www.microtech.thepttc.org/agenda/agenda_aug_17_2005_final.htm.

Calendar of Events/2005 - 2006

2005

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

Sep. 18-20
AAPG, *Eastern Meeting- Mountains of Opportunity,* Morgantown, WV. Contact: www.aapg.org.

Oct. 9-12
SPE, *Annual Technical Conference & Exhibition,* Dallas, TX. Contact: www.spe.org.

Oct. 24-26
IPAA, *Annual Meeting,* Houston, TX. Contact: www.ipaa.org/meetings.

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

Nov. 8-11
IPEC, *International Petroleum Environmental Conference,* Houston, TX. Contact: ipec.utulsa.edu.

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

2006

Feb. 2-3
NAPE, *North American Prospect Exposition,* Houston, TX. Contact: www.nape@landman.org.

Feb. 7-8
IADC, *Health, Safety, Environment & Training Conference & Exhibition,* Houston, TX. Contact: www.iadc.org.

Feb. 21-23
IADC/SPE, *Drilling Conference*, Miami, FL. Contact: www.iadc.org.

Mar. 8
IADC, *Spring Meeting*, Houston, TX. Contact: www.iadc.org.

Mar. 28-29
IADC/SPE, *Managed Pressure and Underbalanced Operations Conference & Exhibition*, Galveston, TX. Contact: www.iadc.org.

Apr. 4-5
SPE/IcoTA, *Coiled Tubing & Well Intervention Conference & Exhibition,* The Woodlands, TX. Contact: www.spe.org.

Apr. 9-12
AAPG, *Annual Convention*, Houston, TX. Contact: www.aapg.org.

Apr. 22-26
SPE, Improved Oil Recovery Symposium, Tulsa, OK. Contact: www.ior2006.org.

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