PTTC
TECHNOLOGY CONNECTIONS

NETWORK News

Petroleum Technology Transfer Council   WWW.PTTC.ORG

DOE Natural Gas & Oil R&D Funding at High Risk

Those of us working closely with DOE are well aware that the Administration's FY06 Budget proposes "orderly termination" of DOE's natural gas and oil R&D program. With this terminology, "at high risk" is certainly a true statement. Around the domestic oil patch it's surprising how many people don't know about this plan for stopping investment in technologies for proven reserves that are increasingly difficult to recover.

Recent historical funding levels for DOE natural gas and oil R&D have been in the $75 million per year range. At that level, DOE can support strategic longer-term R&D (Hydrates), field demonstrations of emerging technologies (Technology Development with Independents), technologies targeting mature stripper well operations (the Stripper Well Consortium) and technology transfer (PTTC) that stimulates application of underutilized or new technologies. DOE is also an advocate

Cont. on page 2

In This Issue

PTTC is a national not-for-profit information network formed in 1994 by oil and natural gas producers. Programs are funded by matching funds from the US Department of Energy (DOE) with funds from State Governments, Universities, State Geological Surveys and Industry. This program would not be possible without contributions from the DOE Office of Fossil Energy through the National Energy Technology Laboratory (NETL).

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Perspectives From The Chairman

Brian Sims, Independent from Madison, Mississippi, took over as PTTC's Chairman in mid-March. His leadership culminates years of involvement in PTTC's Eastern Gulf Region and on the National Board of Directors. Sims has 23 years of experience in oil and gas exploration, development and production, principally in the onshore Gulf Coast Region. Prior to 1991 Mr. Sims worked 10 years as a geologist in various capacities for Clayton W. Williams, Jr., Inc. in Jackson, Mississippi and Houston, Texas. He received his B.S. degree in geology from Millsaps College in Jackson. He is past president of the Mississippi Geological Society and is a member of several oil and gas associations.

Here's the environment the E&P industry faces as I begin my stint at PTTC's helm. Strained natural gas and oil supply, combined with unpredictable volatility in the pricing market has changed the way we do business today. Certainly activity has increased and there are further opportunities to be pursued, however the risk in decision making has also increased proportionally. Human and equipment resources utilized by industry are at the upper limits across all sectors. Product prices are high, but cost of equipment/services is also up so there is that ever-present pressure on profit margin. Independent producers will have to adapt in order to continue to supply the majority of the nations natural gas needs and play a significant role in brownfield reserve production from marginal wells.

To realize the opportunities in front of them, producers must work smart, which often involves integrating new technologies or approaches into the way they do business. Learning about these newer technologies in a time-efficient manner is critical. That's why I've made the commitment I have to PTTC and its "Connection" role. Part of that connection role is helping industry understand, participate in, and benefit from federal investments in natural gas and oil R&D. Those investments themselves are under pressure as the U.S. strives for fiscal discipline in government.. Its time to fulfill the promise made on a common oilfield bumper sticker of the past— "Lord, just give me another oil boom and I promise I won't screw it up." As an industry let's deliver — for ourselves and the country.

In the next year I'm focusing my attention on three areas where I think PTTC can improve upon already solid services.

Volunteer direction. PTTC's activities deliver value when its workshops, newsletters, case studies, and websites address those technology concerns domestic producers face. We have an existing network of volunteer advisors at the regional and national level and we get feedback from the thousands who come to our activities every year. We find though that "the more specific one gets" in expressing what they want to learn about, the more on target the topics, subtopics and speakers in our workshops become. One of my goals is to impress upon PTTC's audience the importance of "communicating to" their regional Producer Advisory Group. When producers run with knowledge they gain, we also need them to share their case studies and provide the data to demonstrate the impact our technology transfer activities are having.

Leverage. Everyone is busy, so it is critical that when producers do spend time learning about new technology they get the most for the time invested - practical bottom line insights must be delivered and that's what PTTC does best. For those in outlying areas where its not feasible to attend, I want PTTC to improve at making insights and information from workshops available online. Online training is not quite like being there, but it can be close. Doing so also helps PTTC better leverage its financial and human resources.

Cont. on page 2

Cont. from page 1, Perspectives From The Chairman

Permanence for PTTC. Federal dollars through DOE's natural gas and oil program, state/university cost-share matches, and industry contributions (primarily time and expenses) currently provide PTTC's resources. It's no secret that the federal resources are what starts the whole process. Stabilizing that federal investment for the long-term is critical for PTTC's permanence. There are other federal opportunities we are looking at to diversify or expand activities. With consistent funding, state contributions will remain strong. PTTC has performed multiple analyses demonstrating the impact to support this public funding. Permanence also involves increasing industry's "green dollar" contribution. PTTC delivers value to the service sector by cost-effectively connecting with producers, so we're working with them to increase their participation. The transfer of technology insights improves the skill set of individual professionals within producers and the consultant sector. We're looking at ways for individuals, and possibly the companies that employ them, to get more involved.

Service companies and especially the large service companies are becoming more and more focused on the large international markets. PTTC has played an extremely important role in helping the service companies understand the needs of the independents and focus some research and training towards their needs. Still, the major R&D dollars in the oil service sector come from the major service companies, which are international, and those dollars follow the highest return on investment, which is typically higher volume producing wells outside the U.S. Since 80% of our domestic production comes from independents that typically lack the ability to test new technology and the service providers have many opportunities to test outside the U.S., this leaves domestic producers in a technology vacuum. Those technologies coming from the international arena generally need adaptation for the low flow volume, lack of natural flow and smaller hole sizes in domestic wells.

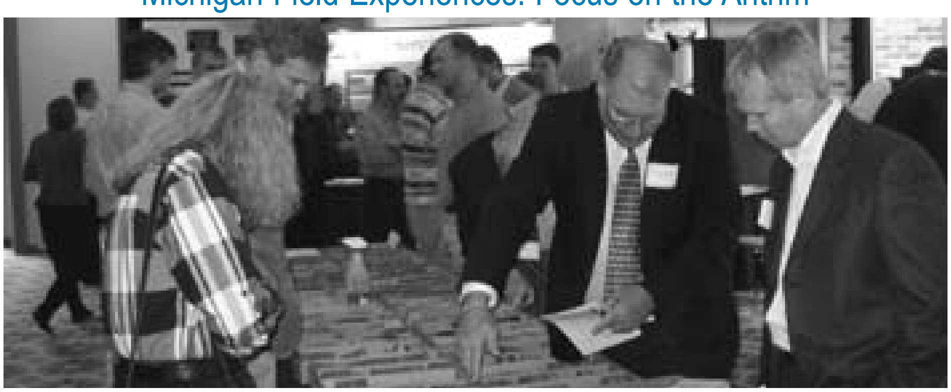
In closing this article, let me state that I welcome input from all concerning PTTC's strategic direction. Feel free to contact me (bsims1@jam.rr.com) or Don Duttlinger, PTTC's Executive Director (dond@pttc.org). PTTC exists to serve the domestic industry. Help us continually improve that service.

Cont. from page 1, DOE R&D Funding at High Risk

for our industry providing valuable information to counter unnecessary regulations, as well as what incentives are best to assure domestic supply. All these are now at risk.

The only way the budget will be restored is through Congress and the Appropriations process. Congress has reorganized this year and a new subcommittee now provides funding for DOE. Many committee members are not familiar with our industry or the DOE Fossil Energy Program. Congress must be better informed about the impact the termination of DOE's programs will have on you, your company and domestic production—both near and long term. Now is the time to express your opinion about the resources that circulate back through the industry, exhibiting a multiplier effect in the domestic economy. The Independent Petroleum Association of America provides a convenient service for expressing your views. (**http://grassroots.ipaa.org/lookup.asp?g=ipaa**) Elected representatives value your informed industry insights.

Michigan Field Experiences: Focus on the Antrim



Michigan Field Experiences, Focus on the Antrim: A full day (14 speakers), 12 exhibits and three cores on display. Bill Harrison, Michigan Basin Core Research Laboratory, points out a feature in a core. 185 people spent their day effectively attending this workshop co-sponsored by Michigan Satellite Midwest PTTC, Michigan Basin Geological Society, and Northern Michigan SPE.

Meeting Alerts

SPE/ICoTA Coiled Tubing Conference
April 12-13, 2005
Woodlands, TX
http://www.spe.org/spe/jsp/meeting/0,2460,1104_1535_2540652,00.html

SPE Production Operations Symposium
April 17-19, 2005
Oklahoma City, OK
http://www.spe.org/spe/jsp/meeting/0,2460,1104_1535_2739324,00.html

IPAA Oil and Gas Investment Symposium
April 18-20, 2005
New York, NY
http://www.ipaa.org/meetings/MeetingInfo.asp?ID=51

IADC/SPE Managed Pressure Drilling Conference
April 20-21, 2005
San Antonio, TX
http://www.spe.org/spe/jsp/meeting/0,2460,1104_1535_2672599,00.html

Southwestern Petroleum Short Course
April 20-21, 2005
Lubbock, TX
http://www.pe.ttu.edu/SWPSC/index.html

Williston Basin Horizontal Well & Petroleum Conference
April 24-26, 2005
Regina, Saskatchewan, Canada
http://www.ir.gov.sk.ca/Default.aspx?DN=4025,3383,3384,2936,Documents

SPE ATW: Modeling & Optimization of Smart Wells
April 25-26, 2005
Huntington Beach, CA
http://www.spe.org/spe/jsp/meeting/0,2460,1104_1535_3097949,00.html

Offshore Technology Conference
May 2-5, 2005
Houston, TX
http://www.otcnet.org/

DEA Challenges for Deep Gas; What Are Our Limits?
May 24-25, 2005
Galveston, TX
http://www.iadc.org/conferences/DEA_2005.htm

Natural Gas Leak Detection Systems Tested at RMOTC

In late September 2004, DOE's National Energy Technology Laboratory sponsored field tests of advanced technologies for remote sensing of natural gas leaks at the Rocky Mountain Oilfield Testing Center (RMOTC) in Wyoming. RMOTC simulated a pipeline system about 7.5 miles long with 15 leak sites with rates ranging from 1 scfh to 5,000 scfh. There were different leak release options, even some decoys, so technologies being tested were truly put to the test.

Tested technologies included: passive infrared multi-spectral scanning, laser-based differential absorption LIDAR (Light Detection and Ranging), hyperspectral imaging, and tunable diode laser absorption spectroscopy. Sensor systems were mounted in an unmodified automobile, a helicopter, or a fixed-wing aircraft. Equipment providers included En'Urga Inc., ITT Industries, Inc. LaSen, Inc., Lawrence Livermore National Laboratories, and Physical Sciences, Inc.

Test results confirm that many of the leak sites were found. General observations from the test results are:

- Leak rates of 500 scfh or higher were detected at least 50% of the time.
- Leak rates of 100 scfh were only detected 15% of the time.
- Leak rates of 15 and 10 scfh were only detected about 5% of the time.
- The 1 scfh leak rate was never detected.
- There were a large number of "false positive" leak sites identified.

With a week of testing, some equipment providers were able to make improvements during the week, while other providers defined modifications for future work. There were also lessons learned about procedures for conducting future leak detection field tests.

The full report (7.3 mb) is available online at ***www.netl.doe.gov/scngo/Natural%20Gas/publications/t&d/final%20Report_RMOTC.pdf***.

DOE Releases LNG Safety Study

DOE recently released a Liquefied Natural Gas (LNG) safety and security study conducted by Sandia National Laboratories. While accepted standards exist for the systematic safety analysis of spills or releases from LNG storage terminals on land, no equivalent set of standards exists for safety or consequences of LNG spills over water. The report reviews several existing studies of LNG spills with respect to their assumptions, inputs, models and experimental data.

The following conclusions, which are only a partial list, were developed by Sandia:

- Risks from accidental LNG spills, such as from collisions and groundings, are small and manageable with current safety policies and practices.
- Consequences from an intentional breach can be more severe than those from accidental breaches, but these intentional breach risks can be significantly reduced with appropriate security, planning, prevention and mitigation.
- The most significant impacts exist within approximately 500 m of a spill, due to thermal hazards, with lower public health and safety impacts beyond approximately 1,600 m.
- Although large, unignited LNG vapor releases are unlikely, they could spread over distances greater than 1,600 m (to 2,500 m for a nominal intentional spill).

Sandia noted that modeling the dynamics and dispersion of a spill over water is hampered by (1) very limited historical and empirical information since current LNG ship design and safety procedures have reduced accidents greatly and (2) the experimental data that are available are more than 100 times smaller than spill sizes currently being postulated for some intentional events.

The full Sandia report is available online at ***www.fe.doe.gov/programs/oilgas/storage/lng/sandia_lng_1204.pdf.***

Canadian Provinces Added to Two DOE Regional Sequestration Partnerships

DOE recently announced that Alberta and British Columbia have joined Saskatchewan and Manitoba as Canadian partners in the Regional Carbon Sequestration Partnerships program. The Department of Energy selected seven original partnerships in August 2003. With the addition of organizations from Alberta and British Columbia, the partnerships now include 216 organizations spanning 40 states, three Indian nations, and four Canadian provinces.

Plains CO_2 Reduction Partnership. In January 2005 Alberta joined Manitoba and Saskatchewan as Canadian provinces participating along with nine states (from Iowa to Montana/Wyoming) in the Plains CO_2 Reduction Partnership. Alberta shares many of the geologic and physiographic characteristics of the existing partnership region. The Alberta Energy and Utility Board and Alberta Environment will contribute information on Alberta CO_2 sources, transportation infrastructure, and the vast geologic formations to the partnership's geographic information system and decision-support tools. Ducks Unlimited Canada will expand their work on characterizing the potential for Prairie Pot Hole Region Wetlands in Alberta to sequester carbon and offset other greenhouse gas emissions through future restoration projects.

West Coast Regional Sequestration Partnership. British Columbia joined six states in the West Coast Regional Carbon Sequestration Partnership in December 2004. British Columbia has a significant amount of hydrocarbon-bearing sedimentary basins that could be used to store CO_2 while simultaneously enhancing recovery. Within these sedimentary basins are saline reservoirs that have huge potential storage capacity but need better characterization. In addition, several mineral deposits exist that could be used to permanently store carbon dioxide by converting it to a solid material. The British Columbia Ministry of Energy and Mines, which has previous experience characterizing their geographic area for sequestration opportunities, has created a database of potential sequestration sites, CO_2 sources, and transportation infrastructure.

View DOE techline at ***www.netl.doe.gov/publications/press/2005/tl_sequestration_canada.html****. For information on all regional sequestration partnerships, visit* ***www.fossil.energy.gov/programs/sequestration/partnerships/index.html.***

EPA's Natural Gas STAR Program

Producer's Tech Transfer Workshop
Co-sponsored by Devon Energy Corporation

April 20, 2005
Oklahoma City, OK

http://yosemite.epa.gov/oar/gasreg.nsf/content/Producers2.htm

PTTC recognizes that products and services featured in "Tech Transfer Track" may not be unique and welcomes information about other upstream technologies. PTTC does not endorse or recommend any of the products or services mentioned in this publication, even though reasonable steps are taken to ensure the reliability of information sources. Input can be directed to HQ@pttc.org.

Horizontal Barnett Shale Wells, To Cement or Not

Horizontal drilling is now commonly used in the Barnett Shale. Pinnacle Technologies looked at Devon Energy's first 23 horizontal wells in the "Core" area. All horizontal pilot wells were cased for borehole stability and, by number were about equally cemented and un-cemented. The laterals were 1,000-4,000 ft in length. Current waterfracs are large, and with longer horizontals, multiple stage fracs are required.

Pinnacle noted that, "while cemented horizontal wells allow for more control of fracture initiation locations, problems are often encountered in achieving fracture initiation. Excessive near wellbore pressure losses with accompanying low injection rates and high treating pressures are often observed in cemented wells. Procedures to alleviate the problem including re-perforating, jet cutting holes, acidizing, and pumping gel and sand slugs are not 100% successful. These steps add time and cost compared with a problem-free treatment."

The logical question then becomes, to cement or not. Pinnacle evaluated production data, on a MMCFD/1000 ft of horizontal lateral length basis, for "cemented" versus "uncemented" wells. There is a compelling graph (Fig. 4) in their newsletter that reveals that uncemented completions have a statistical production advantage over cemented completions in the pilot area.

The article is an interesting read. Those playing the Barnett are urged to read the entire article. *Excerpted from Pinnacle Technologies, Inc. Winter 2005 newsletter, which can be viewed online at* ***www.pinntech.com/subs/newsletters_list.html.***

Missed the CO_2 Conference in Midland?

The annual CO_2 Conference in Midland has become the premier CO_2 flooding event in the industry. Those of you with an interest in CO_2 flooding who were unable to attend last December's event are encouraged to read an extended summary published in the *American Oil and Gas Reporter's* February 2005 issue. Developed by Steve Melzer, director of the Conference, the article briefly summarizes several case studies from fields in several states and the interplay of CO_2 flooding with the growing carbon sequestration movement.

USGS Yukon Flats (Alaska) O&G Potential

Yukon Flats is a region of low, forested hills and flatlands with numerous streams and lakes, situated generally to the east of the Trans-Alaska Pipeline System in east-central Alaska. U.S. Geological Survey (USGS) scientists recently finished their first detailed assessment of the undiscovered oil and gas potential of the Yukon Flats Tertiary Composite Total Petroleum System.

The assessment indicates the probable existence of technically recoverable oil and gas resources, with mean estimates of about 5.5 trillion cubic feet of undiscovered natural gas, 173 million barrels of undiscovered oil, and 127 million barrels of natural-gas liquids in conventional accumulations. These volumes are those that are technically recoverable using current technology and that have the potential to be added to reserves in a 30-year forecast span. The assessment was based on a comprehensive review of available information, including new data from USGS field and laboratory studies.

No petroleum production has been obtained from Yukon Flats, with the one exploratory well finding small quantities of natural gas.

The Yukon Flats National O&G Assessment Fact Sheet 20045-3121 is available at ***http://pubs.usgs.gov/fs/2004/3121.***

Generating Pipeline-Ready Natural Gas From Abandoned Coal Mines

A unique technology developed by Engelhard Corporation is enabling a Southern Illinois gas producer to treat and sell gas from abandoned coal mines and contaminated natural gas that would otherwise remain unrecovered in shut-in wells. By implementing Engelhard Molecular Gate adsorbent-based technology, Grayson Hills Energy, LLC is removing water, nitrogen (N_2) and carbon dioxide (CO_2) from gas produced from its coal mines and natural gas wells.

A system is offered as a prefabricated, modular plant based on patented Molecular Gate adsorbent materials and separation process. It is generating significant interest among gas producers due to its economical processing cost, easy start-up and operation, and environmental friendliness.

The Engelhard technology enables Grayson Hills Energy to treat up to 2.5 MMscfd. The system is located at the wellhead and is powered by an on-site gas-driven generator that uses tail gas from the Molecular Gate adsorbent-based process as fuel. The facility includes an integrated dehydration unit to remove water and simultaneously removes about 7% carbon dioxide and 12% nitrogen while delivering product with less than 4% nitrogen; as required by the interstate pipeline. The process operates by adsorbing contaminants at high feed pressure while delivering the product sales gas with minimal loss of pressure. This ability to deliver methane at near feed pressure minimizes compression requirements. The technology is offered as a modular packaged plant through an engineering and fabrication partner.

For more information, visit Engelhard's website ***www.engelhard.com/Lang1/xDocID54651F74B5FA4F78B7454D4E19D0CDF8/xDocTable_Market/Tab_Overview/MarketID54651F74B5FA4F78B7454D4E19D0CDF8.***

7th Annual Unconventional Gas Conference

(Canadian Society for Unconventional Gas & Petroleum Technology Alliance Canada)

Nov. 8-10, 2005
Calgary, Canada

Soliciting presentations, contact Kerri Markle at kmarkle@csug.ca

ASP Process For Mature Oklahoma Fields

Cano Petroleum (Cano) is a recently formed independent that specializes in increasing production from mature fields using enhanced recovery methods, and field proven alkaline-surfactant-polymer (ASP) flooding is one of the key tools in their arsenal.

Recent Oklahoma acquisitions where Cano is exploring ASP flooding include the Davenport Unit (Prue Sandstone) in Lincoln County and the Nowata Field (Bartlesville Sandstone). In the Davenport Unit Cano drilled and cased two new wells. Data and logs from these new wells are helping design an ASP process for this field. Design of the chemical program is anticipated by year-end 2005 with the program expected to commence soon thereafter. Chemical design is also underway in the Nowata Field, where it is believed that an additional 20-30% of the OOIP could be recovered through ASP flooding. As with the Davenport Unit, design should be completed during 2005. Surtek Inc. (www.surtek.inc) is working with Cano in designing the ASP processes.

Surtek's website summarizes performance in ASP projects. In the Daqing Field in China, a pilot recovered 25% of the OOIP. In a 760-acre Canadian project 14.9% of the OOIP was recovered. Chemical costs for different projects, cited in Surtek's website, range from $0.79 to $3.74 per bbl of incremental ASP oil. With current oil price trends, that type of performance leads to opportunities.

Three critical steps in ASP process design are:

- Fluid design
- Fluid-rock compatibility
- Linear and radial core flooding

Surtek notes that it typically takes from six to nine months to complete the different stages of testing for ASP evaluation. Field execution includes proper mixing and injection of chemical solutions, quality control, and monitoring produced fluids and chemicals.

Content excerpted from "ASP Technology Improves Oil Recovery," American Oil and Gas Reporter, February 2005. Readers are also encouraged to view (1) an interview with Cano staff in February issue of SPE's Journal of Petroleum Technology ***www.spe.org/spe/jpt/jsp/jptmonthlysection/0,2440,1104_0_3431816_3432514,00.html*** *and (2) Surtek's website.*

OTC 2005 Distinguished Achievement Awards

The Offshore Technology Conference's (OTC) Distinguished Achievement Awards for 2005 are:

For Individuals goes to Kim Vandiver for his numerous technical breakthroughs in the dynamics of vortex-induced vibrations that have enhanced the design of structures to withstand high ocean currents.

For Companies, Organizations, and Institutions recognizes Kerr-McGee Oil and Gas Corp. and Technip for their successful global relationship that has pioneered and delivered three generations of spar floating production systems in nine years.

*See OTC press release (**www.otcet.org/2005/index.html** for further information.*

Web-Based E&P Data Viewing

Zebra Geosciences WebDataView™ is a web-based well log, seismic, image and document viewing tool. It provides high quality, rapid visualization for a broad range of E&P data within a web browser and without the need for a download. Petris Technology and Zebra Geosciences have now collaborated to provide WebDataView™ as a viewing tool within PetrisWINDS™ Enterprise system.

See Petris Technology press release ***www.petris.com/pdfs/pr_Petris_ZebraGeo_11Oct2004.pdf*** *and visit Zebra Geoscience's website www.webdataview.com/ for more information.*

Intelligent ESP Pumping Systems Pay Off

Dick Ghiselin, *Hart's E&P*, developed an interesting article summarizing the current generation of intelligent pumping systems for electrical submersible pumps (ESPs). Most systems have the capability to piggyback telemetry and control signals on the power cable itself. With a single cable serving double duty as power and telemetry/control line, environmental feed-throughs at the wellhead and pump are not affected. Sensors can be installed that measure most anything. Technology providers have developed data management, display and analytical routines to realize the value from the data collected. Wells with commonalities can be grouped when it makes sense, and reports can be generated to compare results against design criteria for a single well or group of wells.

Benefits include: protecting pumps that occasionally pump off through automatic shutoffs (and automatic restarts), providing automatic alarms and exception reports to focus field resources, detecting changing reservoir conditions, and sensing wear and predicting failure so service can be scheduled rather than reactive.

Decreasing time between failure is an obvious driving force, but probably equally as valuable is avoiding an ESP pumping sub-optimally for years.

Excerpted from "Pumps Pay Off," Hart's E&P, March 2005 viewable online at ***www.eandpnet.com/ep/0305coverstory.htm***.

New Higher Performance Sucker Rod Connection

Permian Rod Operations, Odessa, Texas, has developed a new high performance sucker rod connection, PRO/KC™. It consists of two pins, one coupling, and one coupling center torque button. This connection can be applied to all new or inspected used rod strings, API or non-API sizes.

Couplings are machined to achieve an end-face width as large as possible for maximum pin shoulder contact area. Pins are machined so that all pin ends have exactly the same dimension from the shoulder to the pin end and the shoulder and pin nose are exactly true relative to each other. Pin ends also receive wet fluorescent magnetic particle inspection and are shot-peened to improve micro-finish and enhance fatigue resistance.

The torque buttons are locked into place so the connections always break on the same side during work over. Pre-load is confirmed by measuring actual pin stretch with a dial indicator; this provides a connection with equal contact pressure on both pin shoulders, equal pre-load stretch of both pin necks and equal contact pressure of both pin noses against the center torque button, creating a pre-load stretch at the coupling center.

In tension and torque tests, the connection outperformed standard API connections by 250% in tension and torque tests. In fatigue testing, the connection lasted an average of 6 times more cycles than API connections under the same cyclic load conditions. In a 3,900 ft progressive cavity-pumped well in eastern New Mexico with conventional rod connections, 15 failures with multiple rod string failures had been experienced in a 38-month period when conventional connections were used. With the new connection, there were five failure events observed in a 13 ½-month period, but the failures were not related to the rod connection.

For further information, visit Permian Rod Corporation's website ***www.permianrod.com/***.

First Ever Rotary-Steered, Casing-Drilled Well

ConocoPhillips, Tesco Corp and Schlumberger Ltd. successfully drilled the first ever rotary-steered, casing drilled well in the Lobo Field in South Texas. ConocoPhillips has been drilling vertically with casing there since July 2001, having now casing drilled some 100 wells. Of these, only 10% have been in the directional mode and those without rotary steering. Beyond reducing flat time by eliminating trips, casing drilling (in the Lobo environment) reduces trouble time—there is less lost circulation and pipe sticking. ConocoPhillips has reduced trouble costs from $92,000/well to about $26,000/well over the last two years.

Part of the incentive for "proving" the concept is taking casing drilling offshore. Proving the concept in an onshore well whose trajectory made moves typical of offshore wells offered advantages. In this well a 5,500-ft interval was drilled using 7-in casing and Schlumbergers 4 ¾-in PowerDrive rotary steerable system. The directional profile included a build to 30º of inclination and a drop back to 6º while making an azimuth change of 145º simultaneously. Using a rotary-steerable assembly during casing drilling means adding a mud motor and measurement-while-drilling (MWD) tool. The MWD tool was placed below the mud motor.

Excerpted from "ConocoPhillips Achieves Industry First With Rotary-Steered Casing Drilling," Oil and Gas Journal, Jan. 10, 2005, and "Ready For The Offshore Reckoning," Offshore Engineer, December 2004.

Devon Donates $2.3 Million to Oklahoma State University

Devon Energy recently donated $2.3 million to Oklahoma State University to build an advanced 3-D visualization laboratory and to fund scholarships and fellowships. The 3,300-square-foot Devon Energy Geology Laboratory will facilitate interaction between student recipients and Devon geoscientists working on real-world field projects. Completion of the lab is expected by fall 2005.

The laboratory will include an advanced graphic station, screens, projectors and Ethernet links enabling the use of cutting-edge technology with high-speed Internet access. In addition, two-way communication between the laboratory and Devon research teams will enhance interaction. In addition, the Devon Energy Scholars Program will fund graduate geology fellowships and undergraduate scholarships for geology and engineering students.

View full press release online ***www2.okstate.edu/pio/devon_energy.html.***

Texas RRC Approves ASR's Hydro-Impact Technology as Enhanced Recovery Technique

Following a review of field performance in Oxy's Elk Hills, the Texas Railroad Commission recently approved an application to treat Applied Seismic Research's (ASR) Hydro-Impact Technology (HIT) as an enhanced recovery technique, granting it tax abatement advantages.

ASR's HIT tool uses seismic wave stimulation technology to shake loose trapped oil. It produces shockwaves with a power ranging from 2 to 10 million watts and a pressure at the wave front in excess of 3,000 psi. The shockwaves are claimed to cover distances of more than a mile. ASR's rental agreement for the U.S. market calls for an up-front payment of $30,000, and $6,500 per month thereafter.

Oxy Elk Hills has been using seismic waves for stimulation since October 2003. Oil production was declining and was at 1,800 bopd before the seismic pilot. After the seismic activity, oil production increased to more than 2,200 bopd. Oxy Permian estimates that in 24 months an additional 124,000 barrels of oil will be produced, based on a 5% increase in oil cut/oil production. ASR's modeling shows recovery could be considerably higher.

For more information, see ASR's full press release ***http://sev.prnewswire.com/oil-energy/20041215/DAW02415122004-1.html*** *or contact Bill Wooden (ph 972-381-4236).*

Carbon Dioxide Storage: Opportunities for the E&P Industry

by Karl Lang with Hart Energy Publishing, LP

Between the two extremes of the climate change debate—denial that warming is taking place on one end of the spectrum and hyperbolized consequences and demands for drastic economic sacrifice at the other end—a middle ground is forming that relies on technological innovation. The idea is that a near-term solution could be to capture and permanently store (sequester) carbon dioxide (CO_2) emissions from our largest and most concentrated streams (power plants, refineries, etc) in geologic formations. This approach would allow us to continue to use our most abundant and inexpensive forms of energy (oil, gas and coal) while reducing carbon dioxide's contribution to global warming. The US Department of Energy sees this approach as one possible transition to an eventual zero-emission, hydrogen-fueled future, and is deeply involved in helping to develop the technologies needed to enable subsurface geologic sequestration on a wide scale.

The oil and gas E&P industry can play a leading role in this effort. Well acquainted with the injection of high-pressure gases, the industry can provide a link between the capture of CO_2 for environmental benefit and the injection of that CO_2 for incremental oil or gas recovery. The best near-term opportunity for safely and *economically* sequestering CO_2 may lie at the original source of much of that nasty carbon, our own oilfields and coalfields.

Once cost effective techniques are developed to capture CO_2, there are significant volumes of economically recoverable oil that can be produced in conjunction with its storage. Nearly all of this resource lies in older fields, many of which are now being operated by independent producers. This article outlines the efforts underway and the estimated size of the potential "prize" that might be producible under different scenarios of technological growth and economic stimulation.

DOE Research Goal is Emission-Free Power Production

The Department of Energy's (DOE) CO_2 sequestration program, managed by the National Energy Technology Laboratory, is comprised of two primary elements: *a core R&D program and a regional sequestration partnership* program, both of which provide support for the development of FutureGen, a $1 billion industry/government partnership to design, build and operate a coal gasification-based, nearly emission-free, coal-fired electricity and hydrogen production plant. The goal of the sequestration element of the program is to enable captured CO_2 to be separated and permanently sequestered in depleted oil and gas reservoirs, unmineable coal seams, deep saline aquifers, or other formations. DOE also manages a variety of other research designed to reduce emissions (e.g., power generation equipment improvements) or to develop other means of disposal than geologic sequestration (e.g., oceanic storage).

Efforts in the core R&D program, underway since 1998, focus on technologies for carbon capture, sequestration, and storage as well as monitoring, mitigation and verification. The regional partnership initiative, announced in November 2002, is comprised of seven partnerships of state agencies, universities, and private companies that form a nationwide network to help determine the best approaches for capturing and permanently storing gases that can contribute to global climate change. The partnerships include 216 organizations spanning 40 states, three Indian nations, and four Canadian provinces. Geographical differences in the use of fossil fuels and the options for sequestration dictate that a regional approach is necessary. The primary purposes of the regional partnerships are to develop the framework needed to validate and potentially deploy carbon seques-

Table 1: DOE Regional Sequestration Partnerships

Region	States	Lead Organization	E&P Industry Partners	Total Partners	Total Funding
Midwest	IN, KY, MI, MD, OH, PA, WV	Battelle Mem. Inst.	BP DTE Energy	31	$3.51 MM
Southeast	AL, AR, FL, GA, LA, MS, NC, SC, TN, TX, VA	Southern States Energy Board	Advanced Resources Intl.	13	$2 MM
Southwest	AZ, CO, KS, NE, NM, OK, TX, UT, WY	New Mexico Tech	Advanced Resources Intl. Burlington Resources ChevronTexaco ERTC ChevronTexaco Permian BU ConocoPhillips KinderMorgan CO2 Marathon Oil Co. Oxy Permian Ltd. Yates Petroleum Corp.	25	$2.15 MM
West Coast	AK, AZ, CA, NV, OR, WA	California Energy Commission	Advanced Resources Intl. BP ChevronTexaco ConocoPhillips KinderMorgan Occidental Petroleum Shell Oil Company Terralog Technologies Western States Pet. Assoc. Oxy Permian Ltd. Yates Petroleum Corp.	47	$2.15 MM
Big Sky	ID, MT, SD, WY	Montana State University		14	$2 MM
Plains	IA, MO, MN, ND, NE, MT, SD, WI, WY	University North Dakota	Amerada Hess Eagle Operating, Inc. Fischer Oil and Gas North Dakota Pet. Council	29	$2.75 MM
Midwest Geologic Sequestration Consortium	IL, IN, KY	Univ. Illinois and IL Geol. Survey	IOGCC KY Oil and Gas Assoc. IN Oil and Gas Assoc. IL Oil and Gas Assoc.	21	$3.25 MM

tration technologies. These partnerships will characterize each region's CO_2 sources and sinks, evaluate alternative sequestration approaches, study regulatory and infrastructure requirements, and develop public involvement and education mechanisms. The timeframe for this effort is two years and DOE funding is roughly $2 MM per partnership, with co-funding by the partners at about one-third of the total. The largest representation of the oil and gas E&P industry in the membership of the regional partnerships is found in the West Coast and Southwest regions. Eleven producing companies and five industry associations are represented overall (*see Table page 7*).

One product of the partnership program is an online GIS database (**www.natcarb.org**) that contains data on CO_2 sources (refineries, power plants, chemical plants, etc.) nationwide. The map layers also depict oil and gas fields, Federal lands, aquifer areas, and a wealth of information (you will need a little patience and a high-speed internet connection). Individual CO_2 emissions sources can be clicked on to reveal plant information. The database is best populated in the Illinois Basin as far as oil and gas fields, but the online system is being added to on a regular basis.

According to Robert Finley of the University of Illinois, the Midwest Geologic Sequestration Consortium (**www.sequestration.org**) has submitted a proposal to DOE for Phase II of the partnership program that includes potential field tests with 10 operators in the Illinois Basin. The list of companies included: Bretagne GP, Continental Resources, Gallagher Drilling, Covington Oil & Gas, Shakespeare Oil, Murvin Oil, Oelze Production, Team Energy, and Howard Energy. A utility, Ameren Corp., also proposed two coalbed methane injection tests. If this Phase II project is approved, only four field tests will be selected. However, the level of interest from independent producers was strong. DOE is currently evaluating all of the Phase II proposals received from the partnerships.

Carbon Dioxide Sequestration and Oil and Gas Recovery

CO_2 can, of course, be injected into depleted oil reservoirs as part of an enhanced oil recovery (EOR) process. This has been successfully carried out for decades in a number of Permian Basin carbonate reservoirs, primarily using purchased CO_2 produced and piped from naturally occurring reservoirs in Colorado and New Mexico. The driver here is recovery of a portion of the 30 to 40 percent of the reservoirs' oil remaining in place after secondary waterflood operations, not CO_2 sequestration. Supercritical CO_2 can become miscible with the oil, acting as a solvent to reduce residual saturation. Naturally, EOR operations have been focused on *minimizing* the amount of CO_2 that remains sequestered per barrel of oil recovered (about 2000 scf or less per barrel), as this CO_2 is a purchased injectant.

Alternatively, CO_2 could be injected into a reservoir that is still producing primary oil but which is nearing the end of its producing life. A credit for CO_2 storage would shift the economics of enhanced oil recovery and alter field practices to *optimizing* CO_2 storage. Use of depleting oil reservoirs amenable to CO_2 EOR as a sequestration option, could provide a value-added benefit in terms of incremental revenue from enhanced oil production which could partially offset the cost of CO_2 capture, which currently is not insignificant.

Captured carbon dioxide could also be injected and sequestered in depleted gas reservoirs. The fact that gas was trapped in such reservoirs over geologic time supports the notion that they are safe repositories for carbon dioxide over the long term. In many cases the infrastructure for injection (surface piping compressors, wells) still exists.

The CO_2 storage capacity of domestic oil and gas formations has been estimated at roughly 150 billion metric tons of CO_2, or roughly 30 years worth of current U.S. emissions (ARI, 2003). Depleting oil reservoirs can't meet all potential CO_2 sequestration needs, but they could provide an early opportunity for sequestration at relatively low cost. Some of DOE's core R&D is investigating trapping mechanisms for CO_2 and developing reservoir management strategies that simultaneously maximize CO_2 sequestration and oil recovery.

Another option also aligned with the oil and gas industry is sequestration in coal seams that are too deep or too thin to be mined economically but are candidates for methane extraction. Primary "coal bed methane" recovery methods, dewatering and depressurization, leave a fair amount of the methane in the reservoir. Enhanced methane recovery can be achieved by sweeping the coal seam with nitrogen or CO_2. The CO_2 preferentially adsorbs onto the surface of the coal, releasing the methane. Two to three molecules of CO_2 are adsorbed for each molecule of methane released. The maximum domestic capacity for CO_2 sequestration in coal seams has been estimated at 90 billion metric tons CO_2, 40 billion metric tons of which is in Alaska (ARI, 2003). Like depleting oil reservoirs, unmineable coal seams could be a good early alternative for CO_2 storage. One potential problem however, is coal swelling. It has been observed that when coal adsorbs CO_2 it swells in volume, restricting the flow of CO_2 into and the flow of methane out of the coal. Work is underway toward minimizing these negative effects.

In addition, the potential for CO_2 storage in formations saturated with brine is enormous compared to oil reservoirs and coal beds and potentially could contain hundreds of year's worth of CO_2 emissions. However, much less is known about injecting into saline formations than is known about injecting into oil reservoirs and coal seams. A portion of DOE's core R&D is focused on improving our understanding of these saline formations.

Field Experience With Oilfield CO_2 Sequestration

Two large CO_2 sequestration projects have been underway for a number of years: an EOR project at Weyburn Oil Field in Canada and injection into a deep saline formation in the Sleipner Gas Field in the North Sea. In addition, a relatively small-scale (one days' worth of CO_2 from an average coal-fired power plant) field test supported by the DOE program is also underway.

The Weyburn project began in 1999. It involves the transport of CO_2 through a 202-mile pipeline from a coal gasification plant north of Beulah, ND to the Weyburn oil field near Regina Saskatchewan. Before building the pipeline, the Dakota Gasification Company released most of the CO_2 into the atmosphere. The CO_2 (96 % pure) is compressed to 2200 psi before being delivered to the pipeline. At Weyburn, the gas is injected into the producing zone, a 100-ft thick Mississippian carbonate at a depth of about 4700 ft. The 70-square mile field area contains more than 1000 wells.

On a daily basis, about 100 MMcf (5000 metric tons) of CO_2 are transported and injected. As of March 2004, about 106 Bcf of CO_2 had been injected and over the project's lifetime a total of 466 Bcf (22 million metric tons) will be sequestered. The operator, EnCana Corporation, estimates that an additional 130 million barrels of oil will be recovered over the next 30 years as a result of the CO_2 injection.

The world's first CO_2 capture and storage project actually began in 1996 in the Sleipner gas field offshore Norway. The operator (Statoil) processes the produced gas to reduce its CO_2 content from 9% to 2.5% before sale. If the extracted CO_2 were released to the atmosphere, Statoil would be required to pay a tax of about US$45 per metric ton, so the company injects the CO_2 into a regional saline aquifer via a single, highly deviated injection well. Over the past nine years the Sleipner operation has injected over 7 million metric tons of CO_2 and the operational plan is to continue to inject for another 15 years. The saline aquifer has the potential to sequester 600 billion tons of CO_2.

A more recent injection project funded by DOE (part of the core R&D program mentioned earlier) is underway in the South Liberty oil field northeast of Houston. The brine-filled injection zone in this field is a sandstone zone within the Frio formation, at a depth of about 5000 ft, on the flank of a salt dome. The site was selected due to its proximity to a large concentration of power plants, refineries and chemical manufacturing plants that emit CO_2. The Gulf Coast region emits roughly 520 million metric tons of CO_2 each year. The Frio sands in this region have been estimated to be capable of storing between 200 and 358 billion metric tons. For this project, injection of about 3000 metric tons from a nearby refinery took place over a three-week period. A number of monitoring, diagnostic and modeling activities have taken place or are underway. The project aims to test these tools and techniques for characterizing a CO_2 injection operation, as well as to demonstrate that CO_2 can be safely injected and securely stored.

Regional Strategies for CO2-EOR

Anticipating a time when economics will support the simultaneous capture and storage of CO_2 and the enhancement of oil production, DOE has undertaken a fresh look at the potential for enhanced oil recovery from CO_2 injection in the nation's older reservoirs. Using the CO_2-PROPHET model developed by Texaco for DOE, Advanced Resources International (ARI) evaluated major reservoirs in six regions of the country: Oklahoma, onshore Gulf Coast, Illinois, onshore California, offshore Louisiana and Alaska. The model was used to determine the economic (>15% ROR BFIT) resource. For each region, the analysts evaluated alternative oil recovery strategies and scenarios. The first scenario assumed CO_2-EOR technology as applied in the past (Traditional Practices Scenario). The second scenario assumed that all of the lessons of past CO_2-EOR technology are applied using state-of-the-art technology and oil price averages $25/Bbl, but CO_2 supply costs remain high at a per MCF cost of about 5% of oil price (State-of-the-Art Scenario). The third scenario examines how the potential for CO_2-EOR could be increased through a strategy involving state tax reductions, federal tax credits, royalty relief and/or higher oil prices that would together be equivalent to a $10 per barrel lift in oil price (to $35) received by the producer (Risk Mitigation Scenario). In the fourth scenario low-cost CO_2 is assumed to be available at a per Mcf cost of about 2% of oil price (kept at $35/Bbl), from existing natural sources and industrial sources via CO_2 capture technologies (Ample Supplies of CO_2 Scenario).

The results for the four areas of interest to most independent producers (onshore lower-48 states) show that at reasonable long-term oil prices of $25-$35 per barrel, there are substantial potential recoverable reserves obtainable from CO_2-EOR if a reliable, reasonably priced source of CO_2 can be found (*Table 2*). Given that some believe that oil prices might move considerably higher than that range, and that up to 30% of the total resource was not evaluated, these totals could be conservative. On the other hand, the lack of existing CO_2 gathering and distribution infrastructure in these areas will make it costly to deliver CO_2 at prices in the 2 to 5% of oil price range, even if new technology lowers the cost of CO_2 capture and separation. Some sort of favorable tax treatment could help to alleviate this risk.

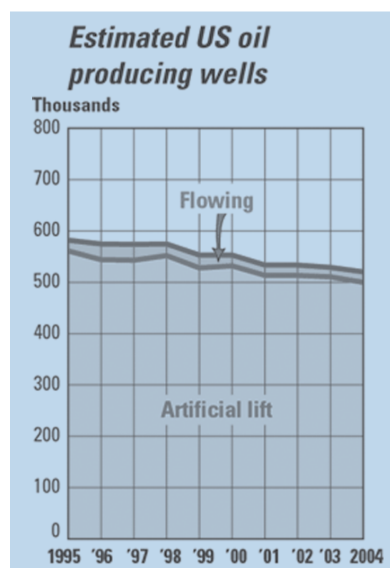
So, while the idea of widespread application of CO_2-EOR outside of the traditional Permian Basin area may seem farfetched, a radical change in the cost of capturing EOR-ready CO_2 or a radical shift in the value assigned to removing CO_2 from the atmosphere could change the picture. The resource remains there, waiting for the right set of circumstances.

Note: *This article was prepared with input from three primary sources: The NETL Carbon Sequestration website at* ***www.netl.doe.gov/****, an article by Kamel Bennaceur (and others) in the Autumn 2004 issue of Schlumberger's Oilfield Review available at* ***www.slb.com/****, and draft copies of ARI's reports: Basin Oriented Strategies for CO_2 Enhanced Oil Recovery. These reports are expected to be published in the near future and will be available on the DOE website at* ***www.doe.gov/****.*

Table 2: Economically Recoverable Resource from CO2-EOR

Region	Fraction of Region's EUR Evaluated	Economically Recoverable Resource by Scenario (MM Bbls)		
		State-of-the-Art	Risk Mitigation	Ample CO2 Supplies
Oklahoma	60.5%	2890	4560	4740
California	90%	1830	3500	3980
Illinois	68.7%	370	470	470
Gulf Coast	58.5%	1860	4330	3570*
Total		**6950**	**9860**	**12,760**

**Ample Supply Scenario includes $25 oil rather than $35 as the others*



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DOE Announces 10 Microhole Drilling Awards

In late January DOE announced 10 project awards, involving $7.7 million of DOE funds and $6.8 million of industry partner funds.

Geoprober Drilling Inc. (Texas). This project calls for drilling three wells with an innovative composite coiled tubing (CT) drilling system. Goal is to confirm the capability to drill microhole exploration wells in water depths ranging up to 10,000 feet. Cost savings, projected at 59% over that for conventional wells, would come by using a smaller drilling vessel and by eliminating the need to deploy and retrieve a large riser.

Gas Technology Institute (Illinois). This project will test a next-generation microhole CT rig, MOXIE. The MOXIE experimental rig, fabricated by Coiled Tubing Solutions, was designed specifically for CT and microhole drilling to 5,000 ft. depths. First deployed for initial testing in a Kansas gas field last year, the rig was able to drill 280-400 ft. p/h.

Confluent Filtration Systems LLC (Texas). Researchers will seek to develop a revolutionary elastic-phase, self-expanding tubular technology called CFEX. The goal is to develop self-expanding well casings to any diameter.

Tempress Technologies (Washington). The goal is to develop a small, mechanically-assisted, high-pressure waterjet drilling tool. A downhole intensifier would boost the pressure that can be delivered by CT, maximizing drilling rates. That in turn would overcome the limited reliability, power, and torque of small-diameter drill motors.

CTES LP (Texas). Researchers will focus on improving the performance and reliability of microhole CT drilling bottomhole assemblies while reducing cost and complexity associated with drilling inclined/horizontal laterals greater than 2,000 ft. This would be accomplished by inducing vibration along the CT drill string, which would eliminate the need for a downhole drilling tractor to mitigate friction.

Technology International Inc. (Texas). This project entails developing and testing a downhole drive mechanism and a novel drill bit for drilling with CT. 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.

Ultima Labs Inc. (Texas). 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 CT drilling of small-diameter (3½ inch) wells at depths shallower than 5,000 feet. Two prototypes are to be delivered.

Baker Hughes Oilfield Operations Inc. (Texas). Researchers will seek to provide a wireless system to help steer drilling in a microbore. Plans call for developing a downhole bidirectional communication and power module and a surface CT communication link.

Gas Technology Institute (Illinois). This project entails designing, developing, and evaluating a counter-rotating motor drilling system 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 CT drill string, this would increase CT drilling effectiveness.

Confluent Filtration Systems LLC (Texas). 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. Plans call for deploying the technology in a demonstration well.

View DOE Tech Line at ***www.netl.doe.gov/publications/press/2005/tl_microhole_selections.html.***

Kansas Exploring Enhanced CBM from Landfill Gas (LFG)

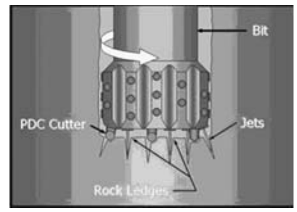
Currently about 4.5 MMCFD of LFG is collected from the Johnson County, Kansas landfill. About half of the gas is methane and the other half is largely CO_2. Now this gas is processed on the surface, resulting in about 3 MMCFD of pipeline quality gas. In a DOE-supported project, the Kansas Geological Survey and other partners are exploring the possibility of injecting untreated LFG into subsurface coalbeds. Since coal readily adsorbs CO_2, the coal would act as a natural processing agent, replacing the current surface processing equipment. Methane in the injected LFG would flow through the reservoir. Additional CBM gas would be produced from enhanced CBM.

Good idea, but will the concept work. In the project the local geology will be evaluated to determine structure, stratigraphy, depth and thickness of underlying coal seams. Coal samples will be obtained and their properties and reservoir conditions ascertained. Response of the samples to LFG gas will be determined. With this data, reservoir simulation will explore the economic potential. A listing of major U.S. landfills overlying coal-bearing strata will be developed.

View DOE project fact sheet at ***www.netl.doe.gov/publications/factsheets/project/Proj324.pdf.***

High-Pressure, Jet Assisted Drilling Tested at RMOTC

In partnership with DOE's National Energy Technology Laboratory, Maurer Technology, Inc. of Houston developed an innovative drilling system that uses high-pressure drilling mud to drive a special mud motor and bit with small diameter drilling jets. High-pressure drilling mud in conjunction with small diameter jets results in very high velocity fluid streams. These streams cut kerfs in the rock at the bottom of the hole allowing the mechanical cutters to easily break the rock ledges, thereby significantly increasing drilling rates.



This system was field tested in a new well drilled in the Rocky Mountain Oilfield Testing Center in Wyoming last year at depths of approximately 4,300 to 5,200 feet. During the test, drilling pressures exceeded 7,500 psi at mud circulation rates of 200 gpm. The drilled interval included a variety of lithologies, ranging from clean, high porosity sandstone to limestone, as well as shale and siltstone.

Significant increases in drilling rate were evident over specific intervals, from two to seven times the conventional historical drilling rate. In some areas drilling rates had to be limited to allow proper cleaning of the hole. Difficulties were encountered with the high-pressure mud motor and nozzles in the drill bits. The mud motor's stator, which had aged during the project, failed downhole. The test was completed by drilling conventionally with the rig's rotary table, high-pressure drilling swivel, Kelly hose and mud pump. The RMOTC drilling crew also had to overcome some mechanical problems to operate the surface equipment used by the new high-pressure system. Overall, surprisingly few problems were encountered showing that high-pressure, jet-assisted drilling can be conducted using conventional commercially available equipment. Rig modifications were minimal and not cost-prohibitive. The most costly item was the high-pressure mud pump.

This field demonstration concluded DOE's involvement in this project. This technology is now available for commercialization by other companies. For more information on commercialization, contact Maurer Technology Inc. (John Cohen, email jcohen@noblecorp.com).

*Content excerpted from RMOTC's fall 2004 newsletter (**www.rmotc.com/Today/fall-news.pdf.***

Stripper Well Consortium (SWC) Selects 2005 Projects

Low-Cost Portable Production Well Tester (Oak Resources, Inc. —Oklahoma). Current low cost portable testers ($10,000) are not accurate enough. First generation portable electronic test units were about $125,000 (after prototyping and proving). Second generation electronic testing units with capabilities across the full range of well conditions developed during an existing SWC project cost about $80,000. This project will develop and test 10 field/area-specific units. Since full capabilities are not required for field/area-specific units, anticipation is that cost can be driven down to $25,000 range. Product acceptance and market forces would then further lower the price range.

Interaction of N_2/CO_2 Mixtures with Crude Oil (Pennsylvania State University—Pennsylvania). A nitrogen huff and puff process has been ongoing in the Big Andy field in eastern Kentucky for over 6 years. The nitrogen obtained through membrane separation technology contains up to 5 percent oxygen. A prior SWC project investigated the phase behavior of N_2/O_2 gases in the presence of hydrocarbon. Field experience has indicated that periodic injection of CO_2 mixed with nitrogen improves well performance. This project will evaluate the behavior of N_2/CO_2 injection and its impact on the recovery process using crude oils from the Big Andy Field and the Chipmunk sandstone in New York.

Uncovering Bypassed Pay in Central Oklahoma (Schlumberger Consulting Services (Schlumberger)—Oklahoma). Schlumberger, the University of Oklahoma (OU) and Sand Resources will develop a methodology to uncover behind pipe potential in mature oil fields. Sand Resources operates 12 stripper wells in the NW Noble Field in Cleveland County. Senior OU petroleum engineering students with faculty guidance are evaluating undeveloped, behind-pipe reserves. Schlumberger, through the use of its Moving Domain Software, will aid in the evaluation and, at the same time, develop a methodology that would be made available to other operators. Schlumberger will identify areas with potential within a five-county region (Cleveland, McClain, Oklahoma, Garvin and Logan counties).

G.O.A.L Automated Casing Swab for Open Hole Completions (Brandywine Energy and Development Company, Inc.—Pennsylvania). Beam Pumps, tubing velocity strings, small diameter tubing and plungers and other conventional techniques are often employed with some finite success in open-hole completions. This project will refit two existing 6.25"or larger open-hole completions with a re-fit well system comprised of a slip lined 3.0" or 4.0" ID spooled non -metallic tubing, metal to non metal connectors, open hole packer assembly, casing stand /stop, and modified G.O.A.L. PetroPump with unique variable diameter seal cups to automatically lift fluids.

Desalination of Brackish Water and Disposal into Waterflood Injection Wells (Texas A&M University—Texas). A joint venture has been created for a two-year pilot project in Andrews, Texas, for inland brackish ground water (BGW) desalination with byproduct disposal into an operating waterflood. Andrews will use Texas A&M's mobile desalination unit. SWC funds will be related to the oil field brine disposal operation. ExxonMobil will inject the concentrate from the reverse osmosis process in their Means field waterflood, realizing cost savings in make-up water requirements.

New Technology for Unloading Gas Wells (Colorado School of Mines (CSM)—Colorado). This project will evaluate a variety of devices. Work will include: (1) studying baffle assemblies, (2) resolving the discrepancy between lab and field performance of vortex tools, (3) transient design simulation of gas well loading and unloading, and (4) test a gas-flow powered pump. One-day short courses on liquid lifting using CSM's flow loop for hands-on demonstration will be continued.

Wedge Pump for Casinghead Pressure Reduction (W&W Vacuum & Compressors, Inc.—Texas). The patented Weatherbee Wedge Pump is thought to have significant advantages over conventional equipment for casinghead pressure reduction. Existing technology cannot pull the volume of vacuum (throughput) necessary and it struggles handling typically high BTU casinghead gas without running into problems handling liquids. This project will build three prototype models and a test stand to simulate common wellhead conditions. Prototypes will be bench tested.

Effect of Completion & Production Practices on Recovery from Knox Formation (James Engineering, Inc.—Ohio). Various drilling, completion, and production methodologies have been applied to the Knox Formation (Rose Run Sandstone and the Beekmantown Dolomite). Completion and production technical issues include: cased-hole versus open-hole completions, matrix acidizing versus fracture stimulation, perforation concentration and interval selection, fluid removal methods, paraffin treatments, operating wellhead pressures, gas sales line pressures, as well as general operating procedures. This study will evaluate the critical factors associated with completion and production practices and the effect on the ultimate reserves predicted.

Real Time Remote Field Monitoring of Plunger Lift Wells (Tubel Technologies, Inc.—Texas). This project will develop a low cost surface system to monitor the plunger lift process in wells, transmit well production streaming audio signals to remote locations, monitor in real time the performance of the entire field and determine if and when the wells stop producing. This new system will acquire the information generated by plunger movement and monitor the fluids and gas being lifted. The information will be transmitted to a central control area where the operator can listen. An automated computer system will also be developed.

Demonstrating Hydroslotter Technology in New York Wells (Hydroslotter Corporation—Canada). Hydroslotting is a two-step abrasive hydrojet completion process. The first step cuts two 180°-phased slots through the casing, cement, and deep (up to 10 ft) into the formation. The second step cycles proprietary remedial chemical reagents via the newly created slots. Effectively, near-wellbore damage is transferred to the distant slot tips. Hydroslotting will be demonstrated in five different well environments in three New York geological zones: Onondaga, Medina, and Theresa. At least one demonstration will be close to a gas-water contact.

Disproportionate Permeability Reduction in Gelled Polymer Systems (University of Kansas (KU), Center for Energy Research—Kansas). A two-well field test involving KU and Vess Oil Corporation, a Kansas independent, will be conducted to determine if the water production rate following a polymer gel water shut-off treatment can be reduced by a process in which the gel that has formed in situ is dehydrated following placement by slow injection of oil. Oil flow channels formed by the dehydration process exhibit preferential permeability to oil over water.

Non-Polymer Water Shut-off Treatment (IMPACT Technologies, Inc.—Oklahoma). A non- polymer water shut off treatment was developed and field tested in Kansas by a major in the 1970s and refined through further testing in the 1990s by an independent. Twelve injection wells and one production well have been treated in 10 properties in central Kansas. This project will test the process in at least 23 more wells. Process advantages include being very low cost (about 50% of current gel polymers), non-toxic, and easy to handle/ mix and pump in the field.

Further Developing PAAL's Elastomeric Casing Plunger Cup Design (PAAL, LLC—Oklahoma). Older methods use cups with the major outside diameter larger than the casing inside diameter. Since cup diameter with PAAL's design cup diameter is smaller than the casing inside diameter, cups do not experience unnecessary wear during descent. Wells with tapered casing strings, as well as those previously excluded due to squeeze cement casing leak repairs, can be produced. Much remains to be determined though about elastomers. This project will modify an existing PAL casing plunger to provide test chambers to expose various elastomers to downhole conditions.

For more information visit ***www.energy.psu.edu/swc.***

Interview with Ali Daneshy, Ph. D., SPE Director, 2005-2008

Prior interviews have provided the perspectives of a larger technology provider and individual innovators. Closing the loop on interviews about technology commercialization and uptake, PTTC sought input from Ali Daneshy, Daneshy Consultants, Intl. In addition to his technical expertise in several areas, Daneshy is well known for his insights on "technology uptake." He has authored columns in *Hart's E&P*, plus led the recent SPE Advanced Technology Workshop on "Accelerating Technology Acceptance." His insights to questions posed by PTTC follow.

Q: *It is self-explanatory that both producers AND technology providers MUST BE INVOLVED for uptake of newer technologies in a timely fashion. Prior interviews have focused on the technology developer's perspective. From your experience working both sides of the equation, what do you think the producer needs to bring to the table for timely uptake to occur?*

A: Acceptance and successful use of new technology is not a trivial task. It requires technical, operational and leadership skills, as well as a progressive attitude. More specifically, these include;

1. *Strong technical backbone related to the new technology*. The more complex or revolutionary the technology, the stronger the required backbone and the difficulty to integrate the new with the old.
2. *Willingness and ability to take risk*. The willingness is mostly a personal trait. Ability is related to access to financial resources, as well as the culture and business drivers of the organization. Organizations need to adopt business measures that reduce the immediate risk of being an early technology adopter.
3. *A healthy mix of long and short term business objectives*. The value of many technologies comes from their long term use.
4. *Time*. Maturity of use and operational reliability of the new technology improves with time. So does the ability to know how and where to apply it. Just as reading golf instruction manuals does not make a person a golfer, reading about new technology does not make an expert. One needs to go through the learning process, which involves actual hands-on experience.
5. *Visibility and measurement*. There is no disagreement about the long term value of technology. If so, it needs to be included as one of the direct measures by which successful business practices are identified.
6. *Involvement*. All new technologies mature with use. During this phase an involved and interested user can play a pivotal role in the speed and direction of technology maturity.

Q: *The circumstances of a very small producer, mid-sized independent, large independent and major are quite different. How does what the producer brings to the table vary with the size of company?*

A: Larger companies are more process and policy-driven than smaller ones. While these improve cost and operational efficiency and predictability, they also may hinder innovation and risk-taking. Larger companies are more likely to have access to broader in-house technical skills, but this also slows down the decision-making process. The technical staff in smaller companies has a larger involvement in purchasing decisions than in larger companies. Larger companies have more elaborate purchasing processes that often discourage acceptance of new technology in favor of lower direct costs. Emphasis on cost is even more dominant in National Oil Companies for whom direct cost is often the only mechanism for awarding contracts.

The reorganization of large companies into smaller Business Units and Asset Teams was intended to create the best of both worlds; the efficiency of a large company together with the speed and focus of a small company. While in many regards this has been a successful business strategy, it is doubtful that it has helped accelerate acceptance of new technology. Within the oil and gas industry, the general opinion is that small and mid-size Operators are more receptive to new technology than the Majors. This point has a tremendous impact on the use of technology by the industry. The profitability of a new technology depends on its ability to go beyond the innovators and early adopters and become acceptable to early majority and pragmatists. This involves larger oil and gas and National Oil Companies.

Market studies clearly show the slow adoption of new technology by the oil and gas industry. Changing this market dynamic is going to be slow and will require awareness and participation of all industry segments. It will require a change in industry business philosophy, shifting focus from short term cost to long term value. Major oil and gas companies with their proven successful record of implementing change are natural candidates to lead this effort.

Dr. Ali Daneshy is the Director of Petroleum Engineering Program at the University of Houston and a partner in Dapish Oil and Gas Strategy Consultants, which provides consultation services related to analysis, business planning, marketing and launch of new technology. He has over 30 years of experience in the development and launch of new technology in the oil and gas industry. During his tenure at Halliburton he was the Vice President of Integrated Technology Products and responsible for the launch of several novel technology-based business units, including Enventure Global Technology.

Dr. Daneshy has published extensively on innovation, use of technology, and novel strategies for profitable technology launch. He also conducts short courses on these topics for the oil and gas industry.

PTTC Tech Info

Solutions from the Field:
Online Technologies to Solve Problems Faced by Independent Producers

Summaries of PTTC region- sponsored workshops. For summaries of more than 100 workshops (of more than 1,000 conducted) and for a listing of the workshops held, logon to: www.pttc.org or for more details, contact 1-888-THE-PTTC, e-mail: hq@pttc.org. For some of the workshops the regions have posted speaker presentations online.

Low Cost Methods for Improved Oil and Gas Recovery — Based on a workshop conducted by PTTC's Central Gulf Region, January 27, 2005 in Shreveport, LA.

Sequence Stratigraphy for Explorationists — Based on a workshop conducted by PTTC's Eastern Gulf Region, January 12, 2005 in Jackson, MS.

Converting Stranded Gas and Lowering Power/Operating Costs —Based on a workshop conducted by PTTC's Texas Region on December 15, 2004 in Midland, TX.

American Oil and Gas Reporter Tech Connection Column

March

PTTC's Online Information Resources Still Expanding

February

Conference Reflects Operators' Strong Interest In CO_2 Flooding

January

Unconventional Gas Demands Learning What Practices Work Best

1st Quarter 2005 Case Studies Petroleum Technology Digest

Microturbine application reduces sour gas flaring, provides partial power (March)

Internet access to well information (February)

Volumetric balancing locates recoverable hydrocarbons (January)

Petroleum Technology Digest is a joint project of Gulf Publishing (*World Oil*) and PTTC. See case studies online at www.pttc.org/case_studies/case_studies.htm. Contact lcole@pttc.org.

Some Regional Recognition

Dr. Iraj Ershaghi, West Cost, Receives
2005 SPE Western Region Award
For Tireless and Selfless Dedication

Bennett Bearden, CPG DPA, Eastern Gulf Region
Elected Alabama's AAPG Delegate
Representing Alabama Geological Society

Alerts Via E-Mail: Another PTTC Service

	PTTC Highlight	Industry Highlight	DOE Highlight
Mar. 24	Leadership Change Occurs Within PTTC Board	Halliburton's VariSeal™ Lightweight Cement System	The Quest for Methane Hydrates in GOM Continues
Feb. 28	Central Gulf Region - New LA Parish Well Reference Product	OTC's "Spotlight on New Technology" Winners	Gas Tips, Winter 2005
Feb. 8	Online Video Presentations From PTTC, Interested?	Baker Hughes INTEQ AutoTrak® Rotary Closed-Loop Drilling (RCLD) Systems	Microhole Awards Announced, New Solicitations for Oil & Gas R&D
Jan. 12	Highlights from December 2004 Network News	ATP Wins Offshore Energy Achievement Innovation/Technology" Award	Still Time For Stripper Well Consortium Proposals — Due February 8

CONTACT THE PTTC REGIONAL RESOURCE CENTER IN YOUR AREA:

Appalachian Region
Director: Doug Patchen
West Virginia University
304-293-2867, ext. 5443
Coordinator: Mark Hoffman, 304-293-2867 Ext. 5446
www.karl.nrcce.wvu.edu

Central Gulf Region
Director: Bob Baumann,
Louisiana State University
225-578-4400
Coordinator: Don Goddard, 225-578-4538
www.cgrpttc.lsu.edu

Eastern Gulf Region
Director: Ernest Mancini
University of Alabama
205-348-4319
Coordinator: Bennett Bearden, 205-348-1880
http://egrpttc.geo.ua.edu

Midwest Region
Director: David Morse
Illinois State Geological Survey
217-244-5527
Coordinator: Steve Gustison, 217-244-9337
www.isgs.uiuc.edu/pttc

North Midcontinent Region
Director: Rodney Reynolds
Kansas University
Energy Research Center
785-864-7398
Coordinator: Dwayne McCune, 785-864-7398
www.nmcpttc.org

Rocky Mountain Region
Director: Sandra Mark
Colorado School of Mines
303-273-3107
www.pttcrockies.org

South Midcontinent Region
Director: Charles Mankin
Oklahoma Geological Survey
405-325-3031
Coordinator: Michelle Summers, 405-325-3031
www.ogs.ou.edu/PTTC/

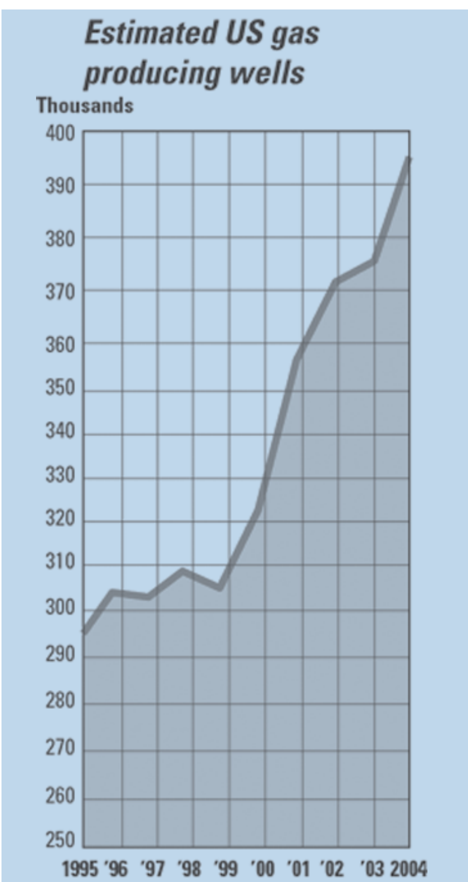
Southwest Region
Director: Robert Lee,
Petroleum Recovery Research
Center, 505-835-5408
Coordinator: Martha Cather, 505-835-5685
http://octane.nmt.edu/sw-pttc

Texas Region
Director: Scott Tinker,
Bureau of Economic Geology
University of Texas at Austin
512-471-0209
Coordinator: Sigrid Clift, 512-471-0320
www.energyconnect.com/pttc

West Coast Region
Director: Iraj Ershaghi
University of Southern California
213-740-0321
Coordinator: Idania Takimoto, 213-740-8076
www.westcoastpttc.org

Michigan Satellite
William Harrison III, W. Mich. Univ.
269-387-8633
http://wst023.west.wmich.edu/pttc.htm

Permian Basin
Bob Kiker, UTPB CEED
432-552-3432
www.energyconnect.com/pttc/pb/



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*PTTC's low-cost regional workshops connect independent oil and gas producers with information about various upstream solutions. For information on the following events, that are sponsored or co-sponsored by PTTC, call the direct contact listed below or 1-888-THE-PTTC. Information also is available at **www.pttc.org/events.htm**. Please note that some topics, dates, and locations listed are subject to change.*

April 2005

4/6 South Midcontinent: *Chart-Type Gas Meters and How To Calculate Gas Production* (Oklahoma Marginal Well Commission) - Wilburton, OK. Contact: 405-604-0460

4/6-7 North Midcontinent: *TORP Oil Recovery Conference* (Univ. of Kansas) - Wichita, KS. Contact: 785-864-7398

4/7 Eastern Gulf: *The New Phase I ESA: "All Appropriate Inquiry" and The Nebulous Nature of Total Petroleum Hydrocarbons* (Mississippi State Board of Registered Professional Geologists) - Jackson, MS. Contact: 205-348-1880

4/12 South Midcontinent: *Chart-Type Gas Meters and How To Calculate Gas Production* (Oklahoma Marginal Well Commission) - Tulsa, OK. Contact: 405-604-0460

4/13 South Midcontinent: *Chart-Type Gas Meters and How To Calculate Gas Production* (Oklahoma Marginal Well Commission) - Oklahoma City, OK. Contact: 405-604-0460

4/13 South Midcontinent: *Polymer Gel Technology* - Norman, OK. Contact: 405-325-3031

4/20 South Midcontinent: *Chart-Type Gas Meters and How To Calculate Gas Production* (Oklahoma Marginal Well Commission) - Ardmore, OK. Contact: 405-604-0460

4/20-21 Texas presentation: *Wellbore Management and Produced Water Management* (Bob Kiker @ Southwestern Petroleum Short Course) - Lubbock, TX. Contact: 432-552-3432

4/21 Appalachian: *Central Kentucky Trenton-Black River Outcrop Analogs; Final Project Review and Core Workshop* (Kentucky Geological Survey) - Lexington, KY. Contact: 304-293-2867 ext 5446

4/21-22 North Midcontinent: *CO2 Flooding Potential in Kansas, workshop & field trips* (KIOGA) - Russell, KS. Contact: 785-864-7398

4/22 Rocky Mountain: *Subsurface Fluid Pressures and Their Relation to Oil and Gas Generation, Migration and Accumulation* - Denver, CO. Contact: 303-273-3107

4/27 North Midcontinent: *Reading the Rocks from Wireline Logs* (Kansas Geological Survey) - Lawrence, KS. Contact: 785-864-7398

4/28 North Midcontinent: *Cased-Hole and Production Log Interpretation for Geologists* (Kansas Geological Survey) - Lawrence, KS. Contact: 785-864-7398

4/28 West Coast: *Gas Field Technology* - Sacramento, CA. Contact: 213-740-8076

May 2005

5/3-4 Texas: *Petroleum Geoscience; Basics of Petroleum Generation, Migration, Trapping and the Oil Business* (Ellison Miles Geotechnology Institute) - Farmers Branch, TX. Contact: 972-860-4630

5/10-11 South Midcontinent: *Morrow and Springer in the South Midcontinent* (Oklahoma Geological Survey) - Norman, OK. Contact: 405-325-3031

5/12 Central Gulf: *Low Cost Horizontal Well Technology* - Lafayette, LA. Contact: 225-578-4538

5/12 Southwest/Texas: *Horizontal Drilling* - Hobbs, NM. Contact: 505-835-5685

5/13 Rocky Mountain: *Geology of Horizontal Reservoirs; Past, Present and Future - A Core Workshop* (RMAG, USGS) - Denver, CO. Contact: 303-273-3107

5/16-20 Eastern Gulf Region: *International Coalbed Methane Symposium* (University of Alabama) - Tuscaloosa, AL. Contact: 205-348-1880

5/19 Rocky Mountain: *SMT Kingdom Suite Data Loading* - Golden, CO. Contact: 303-273-3107

5/20 Midwest: *Pumpers & Well Operations Training* (IOPA Tri-State) - Grayville, IL. Contact: 217-244-93375/23

5/23 Rocky Mountain: SMT Kingdom Suite 2d/3dPAK Interpretation Basics - Golden, CO. Contact: 303-273-3107

5/24 Rocky Mountain: *SMT Kingdom Suite 2d/3dPAK Interpretation II* - Golden, CO. Contact: 303-273-3107

5/24 Central Gulf: *Productivity and Water Management in Potential of Inactive/Marginal Wells* - Lafayette, LA. Contact: 225-578-4541

5/25 Rocky Mountain: *SMT Kingdom Suite VuPak* - Golden, CO. Contact: 303-273-3107

5/26 Rocky Mountain: *GeoGraphix Overview and Refresher* - Golden, CO. Contact: 303-273-3107

June 2005

6/7 Appalachian: *Outcrop Analog for Trenton-Black River Hydrothermal Dolomite Reservoirs* - Albany, NY. Contact: 304-293-2867 X 5446

6/7-8 Eastern Gulf workshop: *PETRA Intermediate Cross Section Techniques* (Mississippi Geological Society) – Raymond, MS. Contact: 205-348-1880

6/13-17 Rocky Mountain: Futures in Energy (Student Training/Internship) - Golden, CO. Contact: 303-273-3107

6/14 South Midcontinent: *Natural Gas Balancing, Current Issues and Known Problems As Affected by JOA* (Oklahoma Marginal Well Commission) - Oklahoma City, OK. Contact: 405-604-0460

6/15 South Midcontinent: *Natural Gas Balancing, Current Issues and Known Problems As Affected by JOA* (Oklahoma Marginal Well Commission) - Tulsa, OK. Contact: 405-604-0460

6/21 Southwest: *Hydraulic Fracturing* - Farmington, NM. Contact: 505-835-5685

6/26-7/1 Rocky Mountain: *Futures in Energy* (Student Training/Internship) - Pinedale, WY. Contact: 303-273-3107

6/26 7/1 West Coast: *COMET 2005* - Los Angeles, CA. Contact: 213-740-8076

6/30 Rocky Mountain: *Coalbed Methane Symposium* (Rocky Mountain Association of Geologists) - Denver, CO. Contact: 303-273-3107

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PTTC Network News Staff:

E. Lance Cole Technical Editor

Kristi Lovendahl Editor

PTTC Headquarters Staff:

Don Duttlinger Executive Director

E. Lance Cole Project Manager

Kathryn Chapman Director of Business Affairs

Phone: 281-921-1720
Fax: 281-921-1723
Call toll-free: 1-888-THE-PTTC
E-mail: hq@pttc.org

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