PTTC TECHNOLOGY CONNECTIONS

News NETWORK

Petroleum Technology Transfer Council WWW.PTTC.ORG

PTTC Facilitating Change

Just when you think you have seen it all, more big changes occur. With everything in flux, its no surprise the public at large and many in industry are asking hard questions about energy. Do we need to access areas with known reserves that are presently off limits? Would tax changes encourage further development? Is there adequate investment available to fund needed operational improvement? Is there enough infrastructure remaining to support this development? Will the energy industry be able to attract an able workforce to take the industry forward? Can deploying known and proven technologies reduce costs and increase production enough to

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PTTC is a national not-for-profit information network formed in 1993 by oil and natural gas producers. Programs are funded primarily by the US Department of Energy's (DOE) Office of Fossil Energy through the National Petroleum Technology Office (NPTO) and Strategic Center for Natural Gas (SCNG) within the National Energy Technology Lab (NETL). Other funding comes from state governments, universities, state geological surveys, and industry contributions.

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Serving Field-Level Operations

PTTC's Appalachian Region has now held several "Well Tender" or "Pumper" workshops. These workshops focus on issues that those in the field operating wells and leases face every day. Increasing their efficiency increases well and lease profitability. The concept evolved from earlier efforts by Roger Willis, vice president of Universal Well Services, with the Independent Oil & Gas Association of New York in 2000. Matt Vavro, training consultant retained by PTTC, Willis and many other industry volunteers worked hand-in-hand to refine the concept. This allows PTTC to deliver the workshops in a neutral setting at multiple locations to realize maximum benefit for industry.

Since spring, PTTC has sponsored five workshops in various states, including Kentucky, West Virginia, Ohio and two in Pennsylvania, each of which drew from 80 to 125 attendees. The workshops started with a video "oil field tour" by Willis, showing how wells are drilled and completed. This was followed by a pointed economics discussion by Vavro, showing how oil and gas investments must compete with all other investment options and the results of small improvements the pumper can make to improve well profitability. Additional presentations dealt with basic well calculations and field safety issues.

Attendees then split into smaller groups, rotating through 10 vendor equipment stations where vendor staff discussed key elements of their equipment and field questions. Knowledge and technology flowed freely both ways. Vendors noted that getting feedback from the people actually using their equipment was invaluable. Experienced staff was able to refresh skills, while new staff became familiar with best practices and procedures currently used throughout industry.

Additional PTTC regional and satellite offices are exploring how similar workshops could be delivered in their producing areas.

Elements Of Success - Relevant information presented by knowledgeable, interesting speakers. Photos from the recent Bremen, Ohio workshop. Left photo-Roger Willis, Universal Well Services, and Matt Vavro, training consultant, demonstrating the "Force of Pressure." Right photo-Matt Vavro, outlining basic calculations for trouble shooting wells. The Westerman Companies offered the use of their facilities and Cooper Cameron Valve/Northrup Equipment/WKM Demco provided lunch.

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impact the U.S.'s reliance on energy from foreign countries? The emerging answers to these questions are determining the fate of many U.S. oil and natural gas producers.

PTTC concentrates its efforts in the technical realm, working diligently to be a neutral forum connecting federal, state and industry stakeholders. There is a strong focus on inter-regional tech transfer, or getting ideas that work in one area more broadly used across the country. How is PTTC able to provide this resource at 14 regional and satellite offices? It starts with people willing to give their time and expertise and share their experiences, both good and bad. Combine this with (1) federal resources granted by the Department of Energy through the National Energy Technology Laboratory, (2) matching dollar for dollar contributions from state governments, universities, state geological surveys and industry contributions, (3) a strong focus on fostering technology application, and (4) ongoing strategic planning based on independent producer input, and you have the organization's outline for progress.

PTTC leverages the knowledge and expertise of all participants. During the 150 workshops that PTTC conducts each year, participants include: (1) technology providers and service companies serving the domestic industry, (2) highly competent consultants both learning and sharing, and (3) experienced producers looking for solutions. The venue is highly interactive, which promotes open sharing. PTTC has noticed more openness among producers, but there is always room for more sharing. Look for topical working groups focusing on specific problems in more detail and "cooperating brainpower" as mainstays for the future.

Technologies That Impact The Bottom Line

PTTC Tech Session— IPAA—New Orleans, Louisiana

Increasing Gas Well Productivity, Casing Drilling, Exploiting Mature Oil Reservoirs and E&P Safety

Monday, October 27, 2003
www.pttc.org/tech_session.htm

On The Rocks at Teapot Dome

The outcrop rim around Teapot Dome, Naval Petroleum Reserve 3 (NPR-3), 30 miles north of Casper, WY, provides an excellent place to examine the Mesaverde Formation. On September 10, 2003, during the recent Wyoming Geological Association Field Conference, the Rocky Mountain Oilfield Testing Center (RMOTC) and PTTC Rocky Mountain Region sponsored a field trip to look at these Cretaceous rocks. Leaders Tor Nilsen and Mark Milliken and a hearty group of geologists and engineers braved blustery weather to view the sequence stratigraphy of the Parkman Sandstone. The photo shows the group at a parasequence boundary; the top of a massive shelf sandstone. In the background, Teapot Dome Field and some of the production facilities of NPR-3 can be seen. For more photos of the field trip, visit www.rmotc.com

Meeting Alerts

IOGCC Annual Meeting

October 19-21, 2003
Reno, Nevada

www.iogcc.state.ok.us/reno.htm

GCAGS Annual Meeting

October 22-24, 2003
Baton Rouge, Louisiana

www.brgs-la.org/gcags.htm

SEG Annual Meeting

October 24-31, 2003
Dallas, Texas

http://meeting.seg.org/registration/

2003 Implementation Meeting
EPA's Natural Gas STAR Program

October 27-29, 2003
Houston, Texas

www.epa.gov/gasstar/workshoppast.htm

IPAA Annual Meeting

October 27-29, 2003
New Orleans, Louisiana

www.ipaa.org/meetings/2003Annual/

Stripper Well Consortium
Tech Transfer Meetings

October 30 — Lubbock, Texas
November 18 — Dubois, Pennsylvania

www.energy.psu.edu/swc/meetings.shtml

IPEC International Petroleum Environmental Conf.—Issues and Solutions in E&P and Refining

November 11-14, 2003
Houston, Texas

http://ipec.utulsa.edu/

CO_2 Week In The Permian Basin

Carbon Management Workshop,
2 Field Trips,
9th Annual CO_2 Flooding Conference
Midland, Texas

www.spe-pb.org/default.asp?pg=co2

Coalbed Natural Resources & Produced Water Management

ALL Consulting LLC of Tulsa, Okla. has prepared a handbook titled Coalbed Methane Produced Water: Management and Beneficial Use Alternatives. The handbook will soon be available from DOE's National Petroleum Technology Office in Tulsa, which provides a comprehensive guide to coalbed methane and associated water issues in CBM basins across the U.S. The goal is to summarize existing knowledge on the geological and environmental constraints of producing coalbed natural gas and to explore alternative treatments and beneficial uses for the large quantities of produced water. The first of a three-part series summarizing the report was recently published in Gas Tips (www.netl.doe.gov/scng/explore/ref-shelf/gas-tips/GasTIPS_summer03.pdf). The editor found it a good read, quickly highlighting the similarities and differences among various U.S. basins.

Drilling of CO_2 Sequestration Test Well in West Virginia

Drilling has begun on a 10,000-foot well to evaluate underground rock layers in New Haven, W. Va., as part of a DOE carbon sequestration research project now underway at the American Electric Power (AEP) Mountaineer plant. Prior to drilling, a seismic survey was conducted. The drilling and seismic survey were preceded by an extensive effort to inform the plant employees, neighbors, local and state officials and other interested groups about the project. The 18-month AEP study will determine whether the geology near the Mountaineer Plant is suitable for injection and long-term storage of carbon dioxide.

Mountaineer was chosen as the test site in part due to its location in the Ohio River Valley area, which is thought to be geologically ideal for carbon capture and sequestration. The Ohio River Valley also is home to many fossil fuel-fired power plants. The study is part of a $4.2 million carbon sequestration research project led by Battelle Laboratories and managed by DOE's National Energy Technology Laboratory (NETL). In addition to AEP, Battelle and NETL, other partners providing financial and in-kind support to the project include BP, the Ohio Coal Development Office, and Schlumberger Limited. Technical support for the project is being provided by experts from NETL and DOE's Pacific Northwest National Laboratory, as well as from West Virginia University, the Ohio Geological Survey, Ohio State University, and several other leading research service providers.

See DOE Techline for full information (http://www.fe.doe.gov/news/techlines/03/tl_sequestration_aepdrilling.html).

Methods for Making Oil and Gas Operations Safe, A Workshop

Industry's overall safety record has improved over the past decade, but U.S. land operations continue to have among the highest incident rates in the world (see Lost Time Incidence article in this section). Many best practices have been developed that can help reduce injuries. An upcoming Houston workshop on November 4&5, sponsored by SPE's Gulf Coast Section, is dedicated to the interchange of practical and tried safety ideas and techniques between operators, contractors and service companies. Special emphasis will be made to offer best practices to companies who do not have dedicated safety resources on staff so both operations and HSE professionals are encouraged to attend. The two-day event will be conducted in a highly interactive fashion, providing time for questions and spontaneous input. Session topics were specifically selected to stimulate thought and open discussion

Halliburton is hosting the workshop at their Oak Park Facility in Houston on Beltway 8 at Bellaire Blvd. Price if registering online (www.spegcs.org/en/calendarevents/view.asp?calendareventid=158) before October 30 is $100. Price at the door will be $150. Lunch is included both days courtesy of Halliburton.

For more information, contact Tom Knode, Halliburton at email tom.knode@halliburton.com.

Beneficial Use of San Juan Basin CBM Water

In one of five projects recently funded by DOE in its coal-fired power plant water management program, the Electric Power Research Institute (EPRI), in a 24-month project, will evaluate the feasibility of using water produced from the extraction of coalbed methane to meet up to 25% of the cooling water needed at the San Juan Generating Station in northwestern New Mexico. To initiate the project, researchers will evaluate the quality, quantity and location of the produced water. They will also evaluate the existing produced water collection, transportation and treatment systems for possible use in delivering cooling water to the generating station. EPRI is joined in this effort by team members: Water and Waste Water Consultants Inc., Public Service of New Mexico, Ceramem, and Pacific Northwest National Laboratory.

The other funded projects (West Virginia University Research Consortium, University of North Dakota Energy and Environmental Research Center, New York State Educational Department, and Tennessee Valley Authority) are not as directly related to the natural gas and oil producing industry.

See DOE Techline for full information (www.fossil.energy.gov/news/techlines/03/tl_powerplant_watermgmt1.html).

Lost Time Incidence Rate Falls in Contract Drilling Industry

According to IADC's 2002 Summary of Occupational Incidents, the drilling industry's worldwide Lost Time Incident (LTI) Rate dropped to an all time low of 0.65, which is 12% better than the previous low of 0.74 in 1999. Fatalities dropped to 15, five less than in 2001 but still higher than the nine that occurred in 1999. Conclusions are based on data from 100 contractors representing about 70% of the worldwide drilling rig-fleet, representing a total of 281 million man-hours worked.

For the U.S., both land and offshore LTI rates improved versus 2001 data, improving 22% and 25% respectively. 2002 LTI rates for land workers are higher than for offshore workers, being 1.73 for land workers versus 0.5 for offshore workers.

Overall, rig employees with time in service between 1-5 years accounted for the most LTI and Recordable injuries. Those with less than one year of service accounted for 40% of LTI and Recordable injuries. Fingers were most vulnerable, followed by feet/ankles and back injuries. Pipes/collars/tubulars is the equipment category responsible for the most incidents, followed by material and slings.

Excerpted from article in Drilling Contractor, July/August 2003, pp. 18-19.

NRC Committee Forming
To Review DOE Methane
Hydrate Research

See Page 7, Summer 2003 Issue
DOE's Fire In The Ice Newsletter

(www.netl.doe.gov/scng/hydrate/newsletter/HMNewsSummer03.pdf)

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.

Oil and Gas Historical Society Created

The American Oil and Gas Historical Society (Society) has been established to preserve the heritage of the U.S. exploration and production industry. Bruce Wells has been named the Executive Director of the Society. According to Wells, the Society seeks to provide a communications network among the nation's 50 oil- and natural gas-related museums. He indicated the Society would work with other oil and gas groups, corporations, state and regional associations, petroleum clubs, Desk and Derrick Clubs, the Smithsonian Institution, universities and libraries to promote community museum programs. The Society is based in Washington, DC. *Give them a call (202-857-4785) and visit their website (www.aoghs.org).*

Identifying "Practices That Are Working"

Benchmarking, especially in the drilling and completions arena with larger operators, is growing. The concept behind benchmarking is simple—open sharing of data by several organizations so that the individual organizations and group as a whole can improve performance. At the smallest scale, a company can do internal benchmarking, comparing performance of different divisions or geographic regions. Maximum value though comes from external benchmarking where one has the opportunity to compare with and learn from others, avoiding the not-invented-here syndrome. Corporate managers see value in knowing how they stack up versus competition, identifying weaknesses and providing direction to improvement efforts. Companies entering new geographic areas can get an idea what to expect by looking at other's performance there.

True benchmarking efforts typically involve a third party group since the effort to assemble data from several companies and analyze it in detail is significant. Results of such efforts are kept confidential to participating companies. Although not as comprehensive, there is a mechanism that can work for the benefit of all if companies involved in a given area will just share their "practices that are working." This can be done without having to share often sensitive detailed data or spend considerable time compiling and analyzing data. This requires trust that the shared "practices that are working" are true. That being the case, groups such as PTTC can play an active role in compiling and widely communicating these practices.

Trust your competitors to honestly share?Are you willing to do the same? Know other operators interested in the same problem or opportunity? Contact PTTC's Regional Directors and explore how, through a topical working group, PTTC might assist in compiling "practices that are working."

Do You Really Want to Improve Your Drilling Performance?

Other industries seem to continually improve their productivity. Are independents, which drill most of the wells in the U.S., seeing continually improving performance in their drilling operations? An article titled "Seven Drilling Myths—Managing Successful Drilling Operations" published in *Journal of Petroleum Technology* provides a simple but thought-provoking discussion of seven drilling myths, listed below, and offers insights on improving performance.

The seven drilling myths:

1. All wells are different.
2. Drilling optimization is difficult to achieve.
3. Each new project represents a new learning curve.
4. Global, regional and area expertise is not transferable, and new or different types of operations require specific high levels of expertise.
5. There is no common process for drilling.
6. Drilling engineers are excited about software or IT tools.
7. Drilling engineers do not expect strong leadership.

The authors note that the lower organizations are on the drilling success curves, the more the above myths permeate their culture. Two keys to turn things around are proposed. First, jump-start the learning curve with the triangle of success—start with expertise, apply sound principles, apply best practices, and use IT tools that work. Second, exercise strong, active leadership through disciplined project management.

Excerpted from "Seven Drilling Myths—Managing Successful Drilling Operations," Journal of Petroleum Technology, Sep 2003, p. 44-48.

Spraberry Well Site of 1st Horizontal Gas Gun™ Stimulation

A 5,200-ft Spraberry well in Borden County, Texas, was the site for J Integral Engineering's first GasGun™ solid propellant stimulation treatment in a horizontal well. Originally drilled in 1987, the well had produced 90,000 bbl before production fell to 10 bopd. The operator had drilled a 500-ft, 4 7/8-in horizontal open-hole lateral to increase productivity, but the lateral never produced any significant quantity of oil even after acidizing. Having used GasGun treatments in several conventional vertical wells, the operator wanted to try one in this horizontal lateral. With concerns about hole stability plus a needed mechanism for getting the GasGun in a horizontal section, a special arrangement for placing the GasGun inside 3 ½-in perforated Hydril pipe was developed.

J Integral Engineering assembled a 240-ft GasGun inside the Hydril perforated pipe while suspended in the well at the surface. The 500 ft of Hydril pipe was connected to 2 3/8-in tubing, and then the entire package was tubing conveyed 5,200 ft vertically with the Hydril pipe and GasGun going into the lateral. The perforated Hydril pipe provided the means to push the 240-ft rubber GasGun "snake" into the horizontal as well as providing the desired hole stability. The tubing-conveyed firing system required for this application consisted of a downhole fireset with battery pack and pressure switch. The fireset was sealed inside a pup joint placed at the bottom of the tubing string at the crossover connection between the Hydril pipe and the tubing. With this approach, filling the tubing with water activates the pressure switch, which detonates the GasGun.

Once on the well, it only took a few hours to position the 240-ft tool at the end of the lateral. Loading the tubing with water successfully detonated the tool. Following detonation, the well began to gas hard at the surface, then died down before the well was shut-in overnight. Since the Hydril pipe and tubing could not be pulled, the tubing was perforated at the bottom of the string. Tubing pressures were higher than ever measured before, but flow was restricted due to suspected bridges. Plans were in place to stimulate the well with acid to clear obstructions.

View the full article online (www.thegasgun.com/Update%2010.PDF).

Online Course, Finding O&G Information on the Internet

Competitive Analysis Technologies (CAT) now offers an online, interactive, self-paced training course about Finding Oil and Gas Information on the Internet. The course resulted from five years of industry training seminars. CAT has taken the lessons learned from these seminars and developed nine modules, including topics such as: Finding Oil & Gas Experts at Universities, Research Institutes and Associations and Improve Your Search Techniques—Find Just the Answers. The online format allows busy professionals to sharpen their "information searching" skills and interaction with the instructor further refines those skills. Those successfully completing the course will receive CAT's CD outlining 4,700 upstream Internet resources.

Cost is $239. AAPG members can receive a membership discount and CEU credits. Visit CAT's website for further course information (www.catsites.com/seminar.html#oilgas).

StimTube™ Treatment Brings Marginal GOM Gas Well Back To Life

Unocal Corp., using Expro International Group PLC's StimTube™ technology, treated a basically non-producing Gulf of Mexico gas well, turning it into a well producing more than 4 MMscfd.

StimTube is an oxidizer-based tool for reservoir stimulation which, when detonated, can generate large volumes of high-pressure gas, as much as 20,000 psi at the reservoir face. These high-pressure gas pulses are effective in perforation breakdown, fracture initiation and elimination of near wellbore damage. StimTube can be run through tubing or on slickline to stimulate existing perforations and eliminate the need for additional stimulation techniques.

Unocal's well, located in the Brazos A105 block, had been initially completed with 300 ft of open perforations in the low permeability Big Hum "D" formation. Production rates and pressures had steadily decreased over time until it was unable to produce against a system pressure of 500 psi. A decision was made to isolate the bottom 138 feet of perforations due to water and sand production and leave 162 feet of perforations open to flow. While this successfully eliminated water and sand production, stable flow could not be initiated. Wellhead pressure would build readily to 1500 psi when shut-in, but when brought online would drop to below line pressure in a matter of minutes.

Based on analysis of original log data and Expro simulations, three 15-feet assemblies of StimTube were used to treat a 75-ft interval. Upon first firing, an immediate pressure increase of 90 psi was observed at the surface. After the second firing, an additional increase of 20 psi was recorded. This same effect was observed following the third firing. The well was brought online with a stabilized flow rate of 4 MMscfd. Payout occurred within less than 10 days. Unocal foresees other applications for the technology.

See July 23rd Expro press release (www.exprogroup.com/), subsequently reported in Oil and Gas Journal (Sep 15, 2003, p. 75)

GTI's Laser Research Program Moving Forward

GTI has been evaluating high-powered lasers for well drilling and completion since 1997. Fundamental research completed in 1999 established that state-of-the-art lasers had enough power to cut rock 10 to 100 times faster than rotary drills. A second phase of research in 2000 and 2001 explored more detailed issues such as laser cutting-energy assessment, rock removal capabilities of pulsed vs. continuous-wave lasers, and the effects of lasing rock in the presence of water. Funding for this second phase was provided by GTI, the U.S. Department of Energy (DOE), PDVSA and Halliburton Energy Services.

DOE recently released funding for the next stage that will establish the technical feasibility of using laser tools to drill natural gas wells and conduct engineering studies leading to prototype tool development. DOE has earmarked about $2.1 million of funding, supplemented by about $1 million in GTI cofunding. GTI has established an exclusive working relationship with IPG Photonics, Inc. applying its high-power, fiber-optic laser technology to well construction and completion tasks. In a parallel effort, GTI recently began a proof of concept project with a major E&P industry partner for a downhole, fiber-optic laser system for perforation of casing.

For more information, contact explorationproduction@gastechnology.org.

IOGCC's 2003 Marginal Oil and Gas Report

The Interstate Oil and Gas Compact Commission's (IOGCC) recently released annual survey established that a significant portion of the increase in U.S. onshore natural gas production in 2002 came from stripper wells. Production from marginal gas wells, which IOGCC defines as wells producing less than 60 Mcfd, represented 10% of the gas produced onshore in the lower 48 states and accounted for 43% of the overall rise in natural gas production. A large percentage of the many coalbed methane wells now being developed would fall in this stripper gas well category. With respect to the number of stripper natural gas wells, the leading states in descending order are Pennsylvania, West Virginia, Ohio and Texas.

Production from the nation's more than 400,000 stripper (< 10 Bopd) oil wells was up slightly to 324 million barrels in 2002, averaging 2.2 Bopd/well. Production from these wells represented 30% of the oil produced onshore in the lower 48 states. With respect to the number of stripper oil wells, the leading states in descending order are Texas, Oklahoma, Kansas and Ohio.

Contact IOGCC (phone 405-525-3556 or www.iogcc.state.ok.us/) to order the report.

Petroleum Abstracts Links Service With AAPG

Petroleum Abstracts (PA) subscribers now can access the PA Discovery database through a website search interface provided by AAPG/Datapages. PA covers the worldwide scientific and technical literature and patents related to oil and gas exploration and production. PA Discovery is a database of about 800,000 Petroleum Abstracts Bulletin entries from 1961 to present. Subscribers pay an annual fee to access PA Discovery. They can choose to search only PA Discovery through AAPG/Datapages or add access to full-text material published by AAPG and other geological societies.

For further information, email aapgdata@aapg.org or call 918-560-9423.

Adding Reserves With Underbalanced Drilling

Underbalanced drilling (UBD) can be a critical component in adding incremental reserves, especially in combination with other technologies. Key benefits from UBD are improved reservoir access, reduced skin damage and better ability to evaluate the reservoir while drilling. This article presents four case histories (two international, two domestic) showing the benefits of UBD. Highlights of the two domestic cases follow.

The **Hatter's Pond Field in Alabama** is an 18,000-ft gas condensate reservoir producing from the Norphlet dolomite and Smackover Sandstone. Discovered in 1974, it has been a prolific field, producing more than 210 Bcf and 50 million barrels condensate. By the late 1990s pressure had declined from original of 9,200 psi to 2,700 psi. In 1999 the 18 producing wells averaged 100-400 Bcpd and 3-6 MMcfd. With lower reservoir pressure recent wells drilled with conventional mud systems had experienced losses to the formation. The Norphlet 10-11#4 was drilled underbalanced using natural gas misted with diesel. After completion it produced 16 MMcfd and 800 Bcpd and had produced 11 Bcf of gas by February 2002. Comparing decline curves with other conventionally-drilled wells, this well's performance exceeds other wells by several times, and that with lower pressure than wells drilled earlier.

In the **Wayne Field in Williston Basin**, producing from the Mission Canyon fractured carbonate, GeoResources drilled the first horizontal well overbalanced. Although the lateral achieved the planned 1800-ft length, data indicated length was at a maximum with overbalanced drilling techniques. The next four horizontal wells were drilled near-balanced or underbalanced. The most immediate benefit was improved access. UBD techniques were primarily responsible for doubling well lengths compared to the first well. In the four following wells, an incremental 8,000 ft of lateral length is attributed to using lateral techniques. The four underbalanced wells cost more to drill, but paid out nearly twice as fast and are expected to deliver twice the reserves and net present value.

Excerpted from "Does Underbalanced Drilling Really Add Reserves?" Drilling Contractor, July/August 2003, pp. 26-29.

UBD Market Overview Report Available

The 2003 Underbalanced Drilling (UBD) Report, a 25-page market overview by Spears and Associates, Inc. (Spears) of the demand and drivers for UBD and the responses by service and equipment companies, is now available for purchase. The report shows UBD activity trends since 1990 with a forecast through 2003. It also breaks out the activity into 3 regions—U.S., Canada and International. The U.S. market is further detailed by the type of UBD activity. Finally, the UBD-related revenues are estimated for six of the major equipment and services providers in this market.

UBD has been an elusive market for most analysts because it has many definitions in the industry and because it is difficult to isolate from other oilfield markets. Spears used the broadest definition of UBD, then segmented the market into 4 tiers for a complete understanding of the market dynamics.

The report contents are as follows: Technology Overview, UBD Methods, Tiers of Complexity, Market Dynamics, Market Size and Growth (U.S., Canada and International), Limited UBD Markets, Impacts on Other Markets, UBD Services & Equipment, Trends and Acquisitions. The cost of the report is $950. Following purchase, it can be emailed immediately via Adobe pdf format or shipped as a bound, printed copy.

For more information, visit Spears & Associates, Inc. website (www.spearsresearch.com/Reports/UBD/Underbalanced_Drilling.htm).

Center for Interactive Smart Oilfield Technologies Forming

The University of Southern California (USC) and ChevronTexaco Corp. recently announced plans to establish a new center, CiSoft, to develop advanced technologies to improve oil and gas exploration and production efficiency. ChevronTexaco will provide R&D funding to establish the center, which will draw upon faculty expertise and resources within the USC School of Engineering's Information Sciences Institute, the Integrated Media System Center and the Petroleum Engineering Program.

CiSoft will focus on developing integrated technologies targeted to the operations of instrumented, intelligent oil and gas fields. ChevronTexaco employees will directly participate in the center's R&D program and the company will provide real-world drilling and production data from oil and gas fields from around the world. ChevronTexaco also plans to provide additional research investments as expanded programs develop within CiSoft. CiSoft will also support a strong educational component drawing top graduates from across the world. USC will create a new master of science degree program which uniquely integrates information technology and petroleum engineering.

CiSoft will form an integral component of ChevronTexaco's *i-field* program, which is focused on the integration of field automation, reservoir simulation technologies, new and emerging well technologies, and real-time reservoir management. Advances in *i-field* technologies and enhanced workflows will help reduce field development costs, speed up the analysis of information and enhance operational reliability.

CiSoft's co-executive directors will be Mike Hauser, *i-field* program manager at ChevronTexaco Exploration and Production Technology Company, and Iraj Ershaghi, USC professor of chemical engineering and director of the Petroleum Engineering Program.

CiSoft is the most recent center formed as part of ChevronTexaco's strategy to develop unique, new research and educational partnership structures. Last year, ChevronTexaco joined with the University of Tulsa to form the Center of Research Excellence in production fluid flow, which is conducting research in the areas of flow assurance, specifically the study of emulsions and multiphase flow, dispersions and heavy-oil chemistry.

See ChevronTexaco press release (www.chevrontexaco.com/news/press/2003/2003-08-29.asp)

Well Stroker Wins ASME Distinguished Innovation Award at OTC

At the 2003 Offshore Technology Conference, Welltec's new product, the Well Stroker, won the prestigious Woelfel Best Mechanical Engineering Innovation Award from ASME (American Society of Mechanical Engineers). The Well Stroker tool enables operators to carry out all aspects of what slick line could achieve in the vertical well - except now it can be achieved in the horizontal using the Well Tractor and the Well Stroker. When the Well Stroker is activated in the horizontal section, it anchors itself against the ID of the casing and can exert a pushing or pulling force of up to 10 tonnes in either direction.

Contact Brian Schwanitz (phone 281-398-9355, email brian@welltec-us.com) for more information, or visit their website (www.welltractor.com).

Affordable Optimization Options for Low Productivity Wells

by Karl Lang

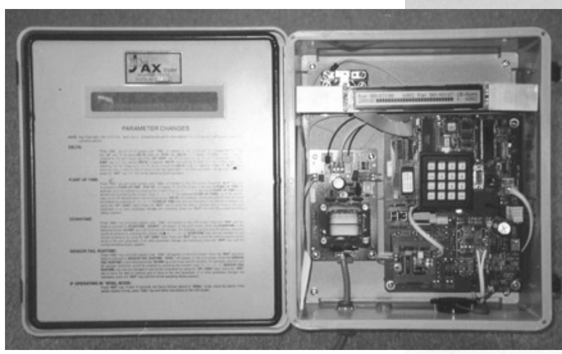
Systems for optimizing production from artificially lifted wells span the spectrum of sophistication, from multiple-sensor, real-time, internet-accessible, remote monitoring and control systems to a simple timer on a rod pump motor. Some would argue that the latter does not really constitute true production optimization technology, and many smaller producers might reply: "***Maybe not, but it is affordable***." The fact is, many small producers cannot afford the capital investment required to take advantage of the benefits that well monitoring and control can provide, an investment that can total thousands of dollars per well once the costs of computer hardware and software, data transmission system installation, power supply enhancements and training are included. While the per well costs drop somewhat as larger numbers of wells are added to a system, the overall economics still can be problematic for stripper wells producing only a few barrels of oil per day.

On the other hand, the benefits of even the simplest applications of well monitoring and and control systems are well established. For example, *pump off controllers* (POCs), also called *rod pump controllers* (RPCs), are a proven technology that has been operating in fields worldwide for over three decades. Most POCs are remote terminal units (RTUs) that monitor conditions, usually by continuously measuring the load on the pumping unit, and initiate a pump shut down based on a pre-set condition set by the operator. By detecting the "pumped off" condition of the well and shutting down the pump, the controller allows time for fluid to enter the wellbore before starting the pump once more.

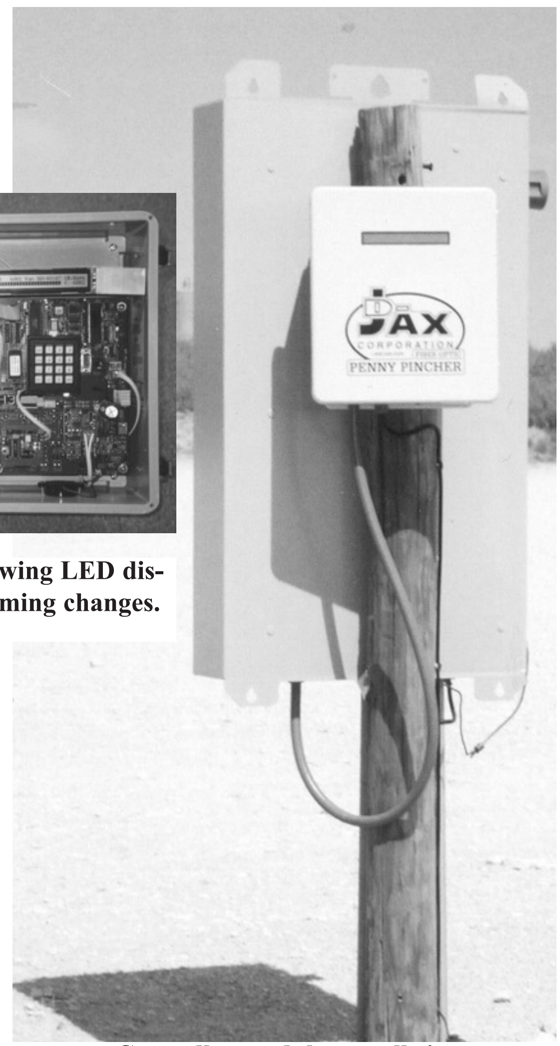
Over-pumping a well or allowing it to be pumped after the fluid level has been lowered below the downhole pump, results in "fluid pound," a condition where the traveling portion of the pump strikes fluid in the pump barrel. This action exerts excess stress on the pump, the rods, the tubing and the pumping unit, contributing to an increased risk of failure. Of course, the cost of the electricity running the pump on an over-pumped well is a wasted investment.

So, by reducing the amount of time a pump is run ineffectively, POCs reduce power consumption. Also, by reducing the number of instances when a well continues to be pumped without a fluid level, POCs reduce the number of well remediations due to pump failures, parted rods or tubing leaks. This in turn reduces down time, maintenance costs and well workover costs. Reported cost savings range from 10% to 20% for electrical power and 25% to 40% for rod, pump and tubing repairs. Production increases from 1% to 7% have also been reported as downtime is reduced and pump efficiency improved.

Recognizing a market for low-cost alternatives that can translate some of these benefits for low-productivity wells, several companies are offering controllers that offer a degree of technology at an affordable price. Two of these are described here.



Interior of J-Dax controller showing LED display and keypad for entering timing changes.



Controller module at well site

Penny Pinching Pump-Offs

Several options exist for producers caught between a need to improve rod-pumped well production efficiency and an inability to finance the large capital investment required for the more sophisticated monitoring and control systems. One of these is the "Penny Pincher" pump-off control from D-JAX Corporation of Midland, TX. This POC operates on a very simple principle: the speed of the pump plunger will increase slightly if the barrel is empty rather than full, and small differences in measured pump-strokes-per-minute can indicate when the well is pumped off downhole. According to Allen Lindsey, General Manager of D-JAX, "The sensor wand mounted on the gearbox pedestal reacts to a magnetic strip on the counterweight and sends a signal to a microprocessor that determines the speed of the rods and compares it to the speed measured at the beginning of a cycle, when the pump is full. When the difference indicates a pumped off condition, the controller shuts down the pump." This is the only sensor and the only measurement utilized by the POC. "Its simplicity makes it reliable, easy to install, easy to calibrate and easy for pumpers to operate," adds Lindsey. A very simple and easily understandable key pad allows each controller to be adjusted or re-calibrated.

The advantage this product offers over a simple timer is of course the fact that an actual measurement of the well's condition is used to control the pump. When a well is run on a timer, adjusting the cycle time (usually in increments of 15 minutes) is a matter of trial and error. With low-productivity wells the operator typically adjusts the run time and then monitors well production. By iteratively decreasing or increasing the run time, the operator can eventually determine the maximum production corresponding to the minimum run time. If, however, the well is producing in a waterflood with varying injection rates, the well's pumped-off fluid level may not remain static over time and an optimal cycle run time may never be realized, even with this time-consuming trial and error method.

According to Lindsey, the D-JAX pump off controller reacts to the *difference* in pump speed rather than an absolute measurement of well condition, and this is an advantage if well conditions change. Says Lindsey, "Paraffin, gas content, and other variables do not affect the controller's ability to identify a pumped-off condition."

For example, a pumping unit running at ten strokes per minute with the pump barrel filled completely on each stroke, would have a single stroke speed of 6000 milliseconds per stroke (msps). As the downhole fluid level drops off and the pump barrel no longer fills completely, the stroke speed increases, dropping the msps value until it reaches a minimum when the well is pumped off, say for example 5982 msps, a "*delta*" of 18 ms. While this increase in speed is imperceptible to the eye, the sensor installed between the gearbox and crank arm can detect and quantify the difference, and thereby determine when the well has pumped off.

The second parameter used by the Penny Pincher is the period between pumping cycles that is required for the fluid level to return to its maximum: the downtime. This parameter is generally set through trial and error, with the help of a dynamometer to determine exactly when the pump is once again filling completely. Of course it is important to accurately determine both the *downtime* and the delta parameters to optimize the well's pumping performance.

The controller also features an option whereby the operator can program the unit to run for only a portion of the pumping time during a certain number of pumping cycles. For example, setting the controller for five cycles at 95% will force the pump to run for 95% of the established pumping time for five cycles, after which, on the sixth cycle, the unit would run until the delta indicated the well was pumped off. This feature is designed to ensure that fluid pound strokes are eliminated, for example, when fiberglass rods are at risk.

The Penny Pincher has been around for 12 years, but D-Jax recently introduced new internal electrical surge protection for the controller. The standard system of thermistors, resistors and varistors proved effective in mitigating damage from nearby lightening strikes but could not prevent catastrophic failures in cases of direct strikes. While rare, these events were costly for the operator.

A solution was found in isolating the POC logic board from the power supply board using fiber optic couplings. The simple fiber optic circuit D-Jax uses between the power supply and the logic board consists of an emitter (transmitter), which converts normal electrical signals to light and sends them through the optical fiber, and a receiver that converts the light signal back to an electrical signal. The isolation begins with the 110 volt power supply which feeds the logic board 12 VAC, reducing the potential for flashover and collateral damage. Another potential source of surges is the sensor circuit coming from the gearbox pedestal. The sensor circuit is conventional copper wire to the power supply and fiber optic from the power supply to the logic board. Any surges brought in by the sensor circuit will stop at the power supply. While this configuration cannot completely eliminate all damage from lightning strikes or other powerful electrical surges, it does minimize the economic impact of damage when such events occur. By isolating the logic board from the power supply board, catastrophic damage will occur only to the power supply, which is about one-fourth as costly to replace as the logic board. The system has proven effective thus far. D-Jax has installed approximately 550 fiber optic-based controls, many in areas where lightning has been a problem, and has yet to see a failure attributable to lightning or other electrical events.

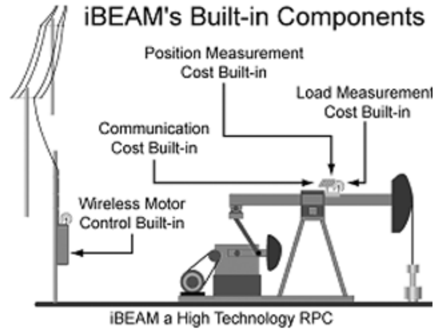
The Penny Pincher gets its name from its price: $1,495 plus a $250 installation fee. Lindsey reports that over 9,000 of these POCs have been installed domestically and worldwide. Overseas applications include Columbia, Argentina, Kazakhstan, Africa, and recently, Poland. While most of the wells employing these POCs are stripper wells, Lindsey adds that some wells producing as much as 200-300 BOPD have them installed. Operators using the bigger bore pumps find the Penny Pincher helpful in preventing fiberglass rod parts.

Following up this low-cost POC option, D-JAX has also recently introduced a wireless dynamometer system priced at $5,995, about half the cost of conventional systems. This product includes a load sensing and data transmission unit that clamps to the polished rod and a data receiver that sits on a truck dashboard and connects to a laptop computer. The system operates up to a distance of 300 feet. D-JAX is currently working with a software developer to provide analytical software.

iBeam Controller Provides High Tech at Low Cost

Another option for operators looking to achieve a level of optimization in their rod-pumped wells is a new wireless rod pump controller recently rolled-out by e-Production Solutions Inc. (eP): the iBEAM RPC. According to Karl Sakocius with eP, Houston, the iBEAM adds a low-cost option to eP's established product line of rod pump controllers.

The iBEAM responds to operators' reluctance to install controllers on low-productivity wells with a unique, self-contained design that uses proven technology without requiring the traditional cabling and trenching associated with most RPCs. "The wireless design eliminates the installation costs of laying cables from the load cell and position sensor on the pumping unit to the controller, resulting in a unit that costs less than $2,000," says Sakocius. "That is about half the cost of prior industry technology."



iBEAM components

The controller uses a strain gauge to measure load and an accelerometer to measure the position of the polished rod, accepted approaches that are used in a variety of RPCs offered by eP and others. Historically, this has proved to be the most accepted method to control rod-pumped wells. A radio signal sends commands to the well's motor starter relay, and communicates operational data for remote monitoring. The radio can also be used to provide data to an operator's handheld device. The controller optimizes the restart timing by readjusting idle time, based on the most recent pump cycle history. Proper timing of the pump cycles keeps the fluid level low, allowing maximum inflow in a low-pressure reservoir, but avoiding the fluid pound mentioned above.

iBEAM's beam-mounted, self-contained, solar-powered sensor and communication unit

The controller uses the load and speed information to generate a dynamometer card that can be used to identify pumped-off status. This data, as well as run time, can also be stored for later analysis. The self-contained unit, clamped to the walking beam of the rod pump, is powered via solar power.

According to Sakocious, a recent beta test of the iBEAM RPC on a low-productivity well in Texas illustrates its benefits for marginal wells. "The well was pumping 6 BOPD at 50% cut from 2,300 ft., on a timer set to pump 12 hours each day. After installing the iBEAM controller, pumping time was reduced to 3 hours per day, with no reduction in oil. With the monthly reduction in pumping hours totaling nearly 270 hours, the monthly savings in power cost alone was $125."

But the savings expected from a reduction in the number of repairs could be much more significant. Depending on the specific conditions, RPCs have reportedly cut the incidence of pump and rod failures more than 20%. The cost savings of a single avoided workover to repair parted rods more than likely would be sufficient to cover an iBEAM installation's entire cost.

The iBEAM RPC provides a relatively low-cost yet technically robust solution to the problem of monitoring and controlling low-productivity rod-pumped wells. It can also serve as a first step for operators who, after becoming convinced of the economic benefits such systems can provide, take further steps toward building an even more sophisticated system for instantly responding to RPC-reported changes in well performance. Ultimately, this can lead to more efficient application of a limited workforce, further cost savings, and improved profitability.

Author: *Karl Lang on behalf of PTTC. For further information, contact Lance Cole at lcole@pttc.org.*

DOE Awards, Advanced Technologies with Independents

Three awards were recently announced in DOE's Advanced Technology Development with Independents Program. Awards were made to Temblor Petroleum Company LLC and Utah Geological Survey for exploration-oriented projects, and Schlumberger Data and Consulting Services received the single award for work in existing fields.

Schlumberger will explore the "Application of Time-Lapse Seismic Monitoring for the Control and Optimization of CO_2-Enhanced Oil Recovery Operations." DOE funding of $2 million will supplement the $12.6 million that Schlumberger is providing. The first objective of this project is to demonstrate the use of cost-effective key and advanced technologies to better characterize oil reservoirs prior to CO_2 flooding. The second objective is to demonstrate the use of advanced seismic technologies to monitor the CO_2 flood front during injection such that "real-time" decisions can be made. The 4-year project will demonstrate the technical and cost effectiveness of the application of these technologies.

Temblor Petroleum Company LLC will evaluate "Use of Cutting Edge Horizontal and Underbalanced Drilling Technologies and Subsurface Seismic Techniques to Explore, Drill and Produce Reservoired Oil and Gas from the Fractured Monterey Formation Below 10,000' in the Santa Maria Basin of California." Temblor and DOE are sharing equally in the $3 million project cost. In California operators are reluctant to use horizontal and UBD due to perceptions about financial, operational and environmental risk, this in spite of very strong geologic and engineering indications that horizontal and UBD would greatly increase success in the fractured Monterey reservoirs. The project proposes to re-drill a well drilled three years ago to 11,400' by Temblor Petroleum on a large seismically-defined structure near the town of Los Alamos in the Santa Maria Basin of California. Cutting edge logging while drilling technology will be used to verify the fracture orientation and change drill direction if required.

The Utah Geological Survey will study "The Mississippian Leadville Limestone Exploration Play, Utah and Colorado - Exploration Techniques and Studies for Independents." The Survey and DOE will share equally in the $535,000 project. The overall objectives are to: (1) develop and demonstrate techniques and exploration methods never tried on the Leadville Limestone, (2) provide the facies, hydrodynamic pressure regime, and oil show quality maps that will be used to target areas for exploration, (3) increase deliverability from new and old Leadville fields through detailed reservoir characterization, (4) reduce exploration costs and risk especially in environmentally sensitive areas, and (5) add new oil discoveries and reserves.

Contact DOE's Virginia Weyland (phone 918-699-2041, email Virginia.Weyland@netl.doe.gov) for more information.

Colorado School of Mines and Penn State Selected For DOE's Career Intern Program

These universities are the first two educational institutions to participate in DOE's new Technical Career Intern Program. DOE Fossil Energy is initiating this program to recruit highly qualified students from leading universities for internships in fossil energy programs and for employment once they graduate.

The objective of the Technical Career Intern Program is to develop a number of highly-rated schools which could provide a "pipeline" of future DOE Fossil Energy employees. Mike Smith, Assistant Secretary for Fossil Energy, noted that two thirds of Fossil Energy staff are eligible to retire within the next four years, creating an urgent need to attract new graduates.

Under the Technical Career Intern Program, graduates would be hired with government commitments to: (1) provide extensive training, (2) pay up to $40,000 of student loans, and (3) pay for optional masters programs in earth sciences or engineering while the new employees continue working part time and receiving their full salary.

In choosing the first two schools, meetings were held with 18 learning institutions. The initial implementation period is anticipated to last up to 36 months with recruitment of student interns beginning in spring 2004. After the pilot program is well underway, it is anticipated that additional schools will be included.

See DOE Techline for full information (www.fossil.energy.gov/news/techlines/03/tl_careerintern_firstschools.html).

Natural Gas Storage Consortium Forming

DOE's National Energy Technology Laboratory recently selected Penn State University to establish and operate an underground gas storage technology consortium. Total cost for the 4 ½-year project is $3 million. The consortium will be industry-driven and emphasize the creation of a balanced research portfolio of practical solutions, short-term projects and basic research. The first phase of the agreement will last 18 months to create the consortium, solicit membership, establish an executive panel of industry experts, refine a technical approach, and select and award initial research projects.

Gas storage wells/fields often suffer a decline in productivity after several years of withdrawal and injection cycling. Current revitalization techniques usually provide only limited, temporary delivery restoration. Additionally, not all regions of current and potential high gas demand possess natural underground reservoirs or salt formations that can support local storage needs.

Research supported by the consortium will include, but not be limited to, technologies to limit and remediate the progressive damage caused by the repeated injection and withdrawal of gas in existing and future facilities, as well as innovative reservoir development and management techniques that can maximize performance. Moreover, research will focus on developing, in close proximity to demand centers, man-made storage systems such as underground mined caverns, gas hydrate storage, distributed liquefied natural gas, and other non-traditional means.

See DOE Techline for full information (www.fossil.energy.gov/news/techlines/03/tl_gasstorage_pennstate.html).

Seven GHG Partnerships Forming

The U.S. DOE recently named seven partnerships of state agencies, universities, and private companies that will form the core of a nationwide network to help determine the best approaches for capturing and permanently storing gases that can contribute to global climate change. Together, the partnerships include more than 140 organizations spanning 33 states, three Indian nations, and two Canadian provinces.

In only the last five years, sequestration research at DOE has risen from small-scale, largely conceptual studies to one of the highest priorities. The seven partnerships will develop the framework needed to validate and potentially deploy carbon sequestration technologies. They will study which of the numerous sequestration approaches that have emerged in the last few years are best suited for their specific regions of the country. They will also begin studying possible regulations and infrastructure requirements that a region would need should climate science dictate that sequestration be deployed on a wide scale in the future. The selected partnerships are:

West Coast Regional Carbon Sequestration Partnership led by the California Energy Commission, Sacramento, CA, and made up of representative organizations from Alaska, Arizona, California, Nevada, Oregon, and Washington.

Southwest Regional Partnership for Carbon Sequestration which will involve the efforts of 21 partners in eight states coordinated by the Western Governors'

Association and New Mexico Institute of Mining and Technology, Socorro, NM.

Northern Rockies and Great Plains Regional Carbon Sequestration Partnership which will be headed by Montana State University, Bozeman, MT, and cover Idaho, Montana, and South Dakota.

Plains CO_2 Reduction Partnership which will extend across Minnesota, North Dakota, South Dakota, Montana, Wyoming and two Canadian provinces. It will be led by the Energy & Environmental Research Center at the University of North Dakota, Grand Forks, ND.

Midwest Geologic Sequestration Consortium which will evaluate sequestration options in the Illinois Basin of Illinois, western Indiana, and western Kentucky. It will be led by the University of Illinois, Illinois State Geological Survey.

Southeast Regional Carbon Sequestration Partnership, headed by Southern States Energy Board, Norcross, GA, and involving Arkansas, Louisiana, Mississippi, Alabama, Tennessee, Georgia, Florida, North Carolina, and South Carolina.

Midwest Regional Carbon Sequestration Partnership covering Indiana, Kentucky, Ohio, Pennsylvania, and West Virginia and coordinated by the Battelle Memorial Institute, Columbus, OH.

DOE will provide approximately $11.1 million to support the partnerships over the next two years. Each group will receive up to $1.6 million, with participating organizations contributing another $7 million, or an average of nearly 40 percent of the initial funding.

See DOE Techline for full information (www.fossil.energy.gov/news/techlines/03/tl_sequestration_partnershipselections.html).

Rocky Mountain Natural Gas, Resource Potential and Prerequisites to Expanded Production

A recently released Department of Energy (DOE) report, intended to stimulate discussion on meeting the Nation's energy challenges, describes well the three prerequisites to advancing natural gas production in the Rocky Mountain region: (1) addressing land-use and environmental concerns, (2) access to markets, and (3) technology advances. All three factors are key to future growth, however this article focuses only on the technology realm. Readers are encouraged to peruse the full report (www.fe.doe.gov/programs/oilgas/publications/naturalgas/rockymtn_final.pdf).

Estimates for technically recoverable natural gas range from 226 to 383 Tcf. Estimates include conventional, tight gas and coalbed methane resources. Volume estimates have historically increased with improved geologic knowledge and technology advances and that trend is forecast to continue. Proved natural gas reserves in the Rocky Mountain states now represent 27% of U.S. reserves, providing 18% of supply.

One of the keys to tight gas development is identifying fracture-prone areas that will have higher deliverability. Advances are being made, but some wells with good fracture networks have encountered high water production early in their life. Thus, exploration technologies are needed to predict both "the presence" of fracture network and "likely saturations."

Continued advances in logging technologies to identify "pay zones" within a broad interval are needed, as well as are advances in hydraulic fracturing technology itself. Horizontal and underbalanced drilling technologies, which are used extensively in Canada and other areas, also could be more widely used.

In 2001, coalbed methane represented over half of Rocky Mountain gas production and 8 percent of U.S. natural gas supply. Industry has learned that drilling/operational practices need to be tailored to different CBM basins. This knowledge base is developing and refinements will continue. Environmental concerns will remain important in further CBM development.

Two Smart Drilling Projects Starting

In cost-shared projects, MASI LLC and Terralog Technologies will investigate "smart drilling" options in two projects managed by DOE's National Energy Technology Laboratory. Total project funding is $1.885 million, with industry providing about 42% of that as cost share.

MASI LLC, Houston, will conduct a two-phase project to determine how micro-bubbles called aphrons help seal permeable and fractured wellbore rock during drilling, minimizing reservoir damage. An aphron is a uniquely structured micro-bubble of air or gas created by combining surfactants and polymers in drilling fluid. Aphrons fill fractures and pores in rocks and other media, creating seals that stop or slow the entry of fluid.

Terralog Technologies, Arcadia, Calif., will research the basic physical mechanisms involved in combined percussion and rotary drilling. There is clear evidence that the combination of percussion and rotary drilling provides significant improvement in penetration rates in hard-rock environments. This has led to advances in "percussion" or "hammer" drills using both mud and air systems. However, the fundamental rock mechanics have not been fully defined and adequately modeled. In addition, there are no practical simulation tools available. As a result, cost and reliability concerns have limited broader application. By addressing these needs, the project will help industry recover vast untapped gas resources contained in deep, hard-rock environments more economically and efficiently.

See DOE Techline for full information (www.fossil.energy.gov/news/techlines/03/tl_smartdrilling_2projects.html).

CO_2: Past, Present and Future and the DOE Role

The use of CO_2 for EOR development has evolved from early laboratory research on miscible fluids in the 1950s, through the pilots and pursuit of CO_2 sources in the 1970s, to full-scale floods in the 1980s, to lower cost floods today. The focus of early DOE research was on phase behavior, mobility control and candidate fields. By the 1970s and 1980s the focus had shifted to field demonstration and model development. Finally in the late 1980s and early 1990s funding was provided for investigating optimal flood design, mobility control, and expanding beyond the Permian basin.

Today, there are 68 commercial CO_2 floods producing approximately 230,000 barrels/day, nearly 4% of the domestic oil production. The majority are still in the Permian basin. Research by the DOE indicates the potential oil recovery could be increased 8- to 10-fold if CO_2 could be made available at all potential target reservoirs for $0.50/mcf or less. Increasingly, new projects are utilizing CO_2-rich anthropogenic sources. The most notable are the Weyburn project in Saskatchewan with CO_2 pipelined from the Great Plains synfuel plant in North Dakota and the recently announced Anadarko Salt Creek project in Wyoming.

Research is focused on understanding the processes and identifying depleted oil, deep coal or saline formations in which CO_2 can be sequestered. The first targets will be the marginal oil fields where most is known, but the focus will shift from maximizing oil recovery to maximizing the CO_2 remaining in the reservoir at the end of the project. Geological formations in the U.S. have the capacity of sequestering over 100 years of total anthropogenic CO_2 generated. Other current research is focused on the capture and separation of CO_2, terrestrial and ocean sequestration, and advanced modeling.

Article courtesy of Dwight Rychel, Northrup Grumman, contractor supporting DOE's National Energy Technology Laboratory in Tulsa, Okla.

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

Summaries of regional workshops recently sponsored or co-sponsored by PTTC are added to its national web site regularly. For more complete summaries, and for a listing of the hundreds of workshops that PTTC has sponsored since 1995, logon to: www.pttc.org. For more details, contact 1-888-THE-PTTC, e-mail: hq@pttc.org.

Understanding Paraffin and Asphaltene Problems in Oil and Gas Wells

July 16, 2003 (Smackover, AR) sponsored by PTTC's South Midcontinent Region

BOTTOM LINE
Although often mentioned together, paraffin and asphaltene are distinctly different in their composition, their behavior and the conditions that lead to deposition. Controlling paraffin and asphaltene problems requires one to understand the conditions that lead to deposition and the different solutions and when each is appropriate. When "total" costs of not treating are considered, chemical solutions are often economically attractive.

PROBLEM ADDRESSED
Paraffin and asphaltene problems can significantly affect well/lease profitability, causing troublesome operational issues, damaging formations and decreasing production. Understanding the nature of paraffin and asphaltene, the conditions that lead to their becoming problems, and solutions for controlling them are important. Speaking from decades of experience, the speaker focused on chemical solutions.

Reading the Rocks from Wireline

March 21, 2003 (Lawrence, KS) co-sponsored by PTTC's North Midcontinent Region

BOTTOM LINE
The science of wireline logging began in 1927, and continues to progress in the scope of equipment, greater depths achieved, higher resolution and improved steering capabilities. The information necessary for modern operators to plan, use and interpret wireline logs has become a complex development requiring specialists to implement. This volume provides information to the independent operator to better understand and evaluate the modern technologies available.

PROBLEM ADDRESSED
The Kansas Geological Survey has developed a number of software programs, interactive websites, and tools to assist the independent operator in using a wide suite of wireline logging methods to better interpret the rocks and make management decisions based on this knowledge.

Trouble-Shooting Rod-Pumped Wells

August 19, 2003 (Tulsa, OK) by PTTC's South Midcontinent Region

BOTTOM LINE
Failure and operating cost reduction begins with an understanding of the basics—equipment, terminology, and sound design principles. Several software packages exist to aid in lift system design. Common failure mechanisms for different components (pumping units, rods, pumps) are known, as are accepted equipment and operating practice solutions. This workshop relayed both the theory and practice of rod-pumping operations, stressing the importance of the team environment in failure reduction efforts.

PROBLEM ADDRESSED
Artificial lift is a fact of life in mature domestic producing operations, and rod pumps are the most prevalent equipment used. Reducing component failures and pumping costs requires one to combine science with field savvy. This workshop relayed information at both levels, providing something for both the novice and expert practitioner.

MesaVerde Group Reservoirs - Field Trip and Workshop

May 21-23, 2003 (Albuquerque, NM) co-sponsored by PTTC's South Midcontinent Region and New Mexico Bureau of Geology and Mineral Resources

BOTTOM LINE
The Mesaverde Group contains significant remaining natural gas in the San Juan Basin. Sophisticated geological models are necessary to predict infill locations based on depositional facies. Less sophisticated models ignore stratigraphic complexities, reservoir facies frequency and scale-dependent attributes that are critical to understanding the reservoir distribution. The most productive facies are channels and beach ridges. Carefully screened outcrop analogs to subsurface reservoirs can be used to model the formations of the Mesaverde Group at the scale of infill wells, and to more accurately predict reservoir distribution. Outcrops demonstrate how new reserves can reside between wells within medium- to small-scale reservoir compartments. Scale-dependent attributes, distribution of depositional facies and the sophistication of the geological model largely control the success of locating successful infill wells. Infill potential of Mesaverda formations is a function of the orientation and aspect ratio of channels and beach ridges, the frequency of channels, and the flow barriers between layers. Optimal stimulation procedure for the Lewis Shale in this area is a single-stage, 150,000 lb. foamed linear gel, hydraulic fracture treatment.

PROBLEM ADDRESSED
The Mesaverde Group is a significant natural gas producer in the San Juan Basin. The reservoirs are more complex than they are often portrayed. Complexities include geological aspects (complex stratigraphy, diverse depositional environments, and geographical variations) as well as regulatory aspects that contradict stratigraphic relationships.

American Oil and Gas Reporter Tech Connection Column

September
PTTC Delivers Technology Solutions In Various Ways

August
Workshop Helps Operators Understand Reservoir Fluids

July
Sharing Examples Of Successful Applications Improves Recovery

3rd Quarter 2003 Case Studies Petroleum Technology Digest

Horizontal Drilling Increases Production in a Reef Formation

Bottom Line: In 1992, SOMOCO Inc. - a Michigan-based company - initially developed the Novi 29 Niagaran reef by drilling a 35° directional discovery well into the southeast corner of the reef. Some eight years later, to increase production and access additional reserves, the well was re-entered, drilling a 417-ft horizontal lateral with a second 272-ft horizontal spur. For a re-entry cost of only $175,000, production more than tripled and estimated ultimate recoverable reserves increased by 233,000 barrels of oil and 606 MMcf. A second horizontal well was subsequently drilled into the north end of the reef. Combined, the incremental reserves attributed to horizontal development are estimated at 283,000 barrels of oil and 1,240 MMcf.

Two-Piece, Flow-Thru Plunger Offers Benefits for Unloading Gas Wells

Bottom Line: ChevronTexaco has successfully employed two-piece, flow-through plungers in South, East and West Texas. By virtually eliminating the shut-in time required for a traditional plunger, lost production is minimized, fewer liquids are forced back into the formation, and less surface fluctuations are encountered. In one well where a capillary string installation was replaced, production increased and $1,740 per month of chemical costs were eliminated. In a 10-well program in West Texas (replacing standard plunger lift in eight wells and two flowing wells), production increased 1,200 Mcfd.

Beam-Operated Gas Compressor Is Profitable in Various Field Applications

Bottom Line: Using the walking beam-operated Beam Gas Compressor (BGC), operators can increase production and reduce operating costs on rod-pumping wells by drawing gas and gas pressure from the casing, alleviating the problem of gas interference in the downhole pump. Operators are utilizing the BGC to force casing head gas into high-pressure sales lines. Operators find the BGC is the solution to compress casinghead gas in fields where electricity is not available for conventional compression methods. Some operators experience increases of up to 40 bopd with associated gas and compression expense savings of $20,000 or more.

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.

Alerts Via E-Mail: Another PTTC Service

	PTTC Highlight	Industry Highlight	DOE Highlight
Sept. 18	Just an MCF Per Day	IAGC Detonator Guidelines	Two New "Smart Drilling" Projects Awarded
Aug. 21	Southeastern Louisiana's Shallow Gas Potential	Expandables—Current Products, R&D, & The Future	DOE Names 7 Carbon Sequestration Partnerships
Aug. 7	Regional Activity Sustained at Record Levels	Lower Cost POC System for Marginal Wells	Lowering LNG Costs, Gasification & Salt Cavern Storage
July 17	Student Interns—Learning Industry, Helping Sponsoring Companies	Joint Industry Project Exploring Deep Gas Well Dewatering	Science-Based Model for Protecting Tundra

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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**. Please note that some topics, dates, and locations listed are subject to change.*

October 2003

10/2	Appalachian: *Improving the Bottom Line By Enhancing Your Data Management Skills* - Morgantown, WV. Contact: 304-293-2867 ext 5446
10/6	Appalachian: *Carbonate Well Log Interpretation and Reservoir Characterization of Carbonates in the Appalachian Basin* (Ohio Geological Society, Ohio Oil & Gas Association) - Columbus, OH. Contact: Peter MacKenzie 614-781-3271
10/9	Appalachian: *Converting Anomalously Pressured Gas Resources to Energy Reserves* - Washington, PA. Contact: 304-293-2867 ext 5446
10/9	Eastern Gulf: *AVO Technology* - Jackson, MS. Contact 205-348-4319
10/13	*PTTC session @ AAPG Midcontinent Section Annual Meeting* - Tulsa, OK. Contact: 918-241-5801
10/14	South Midcontinent: *Polymer Treatments for High Water Cut Wells* (Marginal Well Commission) - Tulsa, OK. Contact: 405-604-0460
10/13-15	Eastern Gulf: *2003 Oil & Gas Forum, E&P Technical Issues* (US Oil and Gas Association) - Point Clear, AL. Contact: 205-348-4319
10/15	South Midcontinent: *Polymer Treatments for High Water Cut Wells* (Marginal Well Commission) - Oklahoma City, OK. Contact: 405-604-0460
10/16	Texas Lunch and Learn: *Low-Cost Rod Pump Control* (eProduction Solutions) - Midland, TX.
10/22	South Midcontinent: *Cromwell Play* (Oklahoma Geological Survey) - Norman, OK. Contact: 405-325-3031
10/23	Texas Lunch and Learn: *Low-Cost Rod Pump Control* (eProduction Solutions) - Houston, TX.
10/23	North Midcontinent: *Crash Course in Log Analysis; An Excel Spreadsheet Workshop* (Kansas Geological Survey) - Lawrence, KS. Contact: 785-864-7398
10/23	Midwest core: *Trenton/Black River, Core Workshop and Case Studies Possibilities Within the Michigan Basin and Similarities Outside the Basin* - Mt. Pleasant, MI. Contact: 269-387-8633
10/24	North Midcontinent: *Practical Log Analysis Guide to Oil & Gas Fields of Kansas* (Kansas Geological Survey) - Lawrence, KS. Contact: 785-864-7398
10/24-25	Rocky Mountain: *Utah Coalbed Methane Conference & Field Trip* (Society of Petroleum Engineers) - Salt Lake City, UT. Contact: 303-273-3107
10/27	PTTC Tech Session @ IPAA: *Technologies, New & Old Impacting The Bottom Line* - New Orleans, LA.
10/29	Appalachian: *Coalbed Natural Gas* (West Virginia Development Office) - Roanoke, WV. Contact: 304-293-2867 ext 5446
10/30	West Coast: *Economics of Oil Field Automation* - Valencia, CA. Contact: 213-740-8076

November 2003

11/12	Central Gulf: *Reservoir Fluids 2003, PVT and Beyond* - Lafayette, LA. Contact: 225-578-4542
11/12	Rocky Mountain: *Successful Technologies and Practices for Dealing With Produced Water* - Denver, CO. Contact: 303-273-3107
11/12-13	South Midcontinent field trip: *Cromwell Play* (Oklahoma Geological Survey) - Ada, OK. Contact: 405-325-3031
11/13	Southwest: *Electronic Resources for NM Petroleum Data* - Roswell, NM. Contact: 505-835-5685
11/14	Rocky Mountain: *GeoGraphix Training, An Overview and Refresher* - Golden, CO. Contact: 303-273-3107
11/17	South Midcontinent: *Cromwell Play* (Oklahoma Geological Survey, Oklahoma City Geological Society) - Oklahoma City, OK. Contact: 405-325-3031
11/19	Rocky Mountain: *Inexpensive, Rapid Cross-Section Generation Utilizing Riley Electric Log's Raster Log Images and Divestco's CrossLog™ Suite* - Golden, CO. Contact: 303-273-3107
11/20	West Coast: *Technology and Economics of Horizontal and Multilateral Wells* - Valencia, CA. Contact: 213-740-8076

December 2003

12/10-12	Texas/Southwest: *9th Annual Permian Basin CO_2 Conference* - Midland, TX. www.spe-pb.org
12/12	West Coast: *Economic Optimization in Marginal Fields* - Los Angeles, CA. Contact: 213-740-8076

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