Maintaining A Strong Focus on Produced Water

After several months hard work compiling a concise operator-oriented manual on "Produced Water and Associated Issues," PTTC's South Midcontinent Region recently completed a series of workshops in Oklahoma and Arkansas. The workshops were held in cooperation with the Oklahoma Geological Survey, Oklahoma's Marginal Well Commission and SPE chapters in Tulsa and Oklahoma City.

The manual, developed by Rodney Reynolds (Kansas) and Bob Kiker (Texas), addresses a key constraint on oil production identified in PTTC's DOE-supported PUMP (Preferred Upstream Management Practices) project. The manual captures insights from numerous PTTC workshops held in prior years, preferred practices for controlling well failures from interviews with operators, and information from other sources. At its core, the manual addresses three key questions:

- Do you know if you're producing more water than you have to?
- If so, do you know accepted techniques for reducing water production?
- If you must lift a lot of water, are you satisfied that you are doing everything you can to control your operating costs?

The entire manual is online on PTTC's website (www.pttc.org). Plans are already in motion to repeat the workshop in several other regions during 2003.

PTTC’s West Coast Region, also part of PTTC’s PUMP project, recently announced that $300,000 of supplemental funding had been obtained from the California Energy Commission (CEC). Work from this funding will focus on the sources of excessive water production in California. Solution templates showing producers how to implement effective water control methods appropriate for different geologic environments in California will be developed. The funds also provide for limited field demonstration. Additionally, Global Energy Partners has incentive funds for field work to reduce water/power consumption in another ongoing program (www.cutopex.com) sponsored by California Public Utilities Commission.
Many DOE programs are designed to encourage environmentally responsible domestic production from marginal fields operated primarily by independent producers. Participation in the form of cost share from industry, state budgets and academia provides substantial leverage for these programs. But the reality is that federal budgets are under strain and even programs with attractive benefits are under great scrutiny.

R&D programs by major producing companies have been significantly downsized. The service sector is shouldering more of the R&D responsibility but stock market investors force companies to focus on short-term results. Investment in the domestic energy sector is severely challenged. All factors combine to create an environment where technologies appropriate for mature U.S. reservoirs receive inadequate resources for development or adaptation. In this environment, there is a role for federal funding.

The federal government balances short-term and long-term objectives in providing reliable and affordable energy to consumers across the country. In the short term, DOE-supported R&D is making an impact in reducing risks for smaller independent operators and many would like that work to continue. These projects would not be possible today without participation from DOE. This is exemplified in the California project (see article page 1) which focuses on improving energy efficiency while dealing with vast amounts of produced water.

The role for government in long-term, high-risk R&D investments is to ensure new technologies directed at more unconventional resources continue to enter the pipeline to commercialization so they are available in the future. These projects have significant potential for leveraging developing technologies in other industries for application in the energy industry. Leveraging extends scarce resources and speeds commercialization. Adequate funding is essential to stimulate the continued flow of technology into the industry.

### Department of Energy Oil & Gas R&D Budget

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<th>FY03 (MM $) Actual</th>
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Bill and Linda Harrison at Western Michigan University in Kalamazoo provide valuable PTTC outreach to Michigan industry, but PTTC is only part of their vision. There is an active campaign to provide a new building for the Michigan Basin Core Research Laboratory (MBCRL). Current space is filled to the walls with core and sample boxes which require a proper storage climate. MBCRL is envisioned as a focal point for bringing together Michigan data from many sources making hard copy data available electronically and housing valuable cores.

### Meeting Alerts

- **Southwestern Petroleum Short Course**
  - April 16-17, 2003
  - Lubbock, Texas
  - [www.pe.ttu.edu/SWPSC/index.htm](http://www.pe.ttu.edu/SWPSC/index.htm)

- **11th Annual Williston Basin Horizontal Well Conference**
  - April 27-30, 2003
  - Saskatchewan, Canada

- **Offshore Technology Conference**
  - May 5-8, 2003
  - Houston, Texas

- **AAPG Annual Meeting**
  - May 11-14, 2003
  - Salt Lake City, Utah
  - (see ad on page 14)

- **DOE’s 4th Annual Small Business Conference**
  - May 12-15, 2003
  - Albuquerque, New Mexico
  - [www.smallbusiness-outreach.doe.gov/annual/index.html](http://www.smallbusiness-outreach.doe.gov/annual/index.html)

- **SPE 2003 Forum Series**
  - July 13-18: Drilling Rigs of the Future
  - July 13-18: Eliminating Wastes & Emissions
  - July 20-25: Decommissioning & Well Abandonment
  - Park City, Utah
  - [www.spe.org](http://www.spe.org) (meetings, 2003 calendar)
eTools for Safety in Oil and Gas Well Drilling and Servicing

Working with industry, the Occupational Safety and Health Administration (OSHA) has developed an online eTool for Well Drilling and Servicing. This eTool, accessible at www.osha.gov/SLTC/etools/oilandgas/index.html, is a stand alone, interactive, web-based training tool designed to augment company safety programs. Current sections, each with additional submenus, include: site preparation, drilling, well completion, servicing, plug and abandon, and general safety. The Association of Energy Service Companies, along with representatives from the American Petroleum Institute and International Association of Drilling Contractors, worked with OSHA in developing the eTool.

Ceramicrete-based Sealant for Permafrost Environment

In a project within DOE’s Natural Gas and Oil Technology Partnership (NGOTP), chemically bonded phosphate ceramic (CBC) borehole seals are being evaluated for oilfield applications. CBCs are cement-like, rapid-setting dense materials with great tensile (connected porosity of <2 percent) and compressive (>8000 psi) strengths. They are self-bonding and bond with sandstones, shales, and other types of formation rocks.

CBC sets within hours, even in saline water, is stable in pH 3-11 environments, and is both drillable and machinable. It so happens that CBC sealants also exhibit good properties at low temperatures as might be encountered in a permafrost environment.

Argonne National Lab (ANL) is performing laboratory tests to explore this niche permafrost application. In laboratory tests, characteristics of Ceramicrete-based sealant with Class C and F ashes was monitored at permafrost conditions. ANL has plans for further testing with hollow silica spheres, which would lower the thermal conductivity even more without altering pumping characteristics.

For further information about this niche application or ceramic sealant work in general, contact Arun Wagh, phone 630-252-4295, email waghi@anl.gov.

State Rules and Regulations on CD-ROM

The Interstate Oil and Gas Compact Commission (IOGCC) recently released a new CD-ROM, Summary of State Statutes and Regulations for Oil and Gas Production. Coverage is provided for 37 states, plus IOGCC’s international affiliates (Republic of Georgia and government of Newfoundland and Labrador, Canada). Among others, topics include: bond, casing and tubing, completion, documents required, drilling permit, spacing, underground injection, and unitization.

Purchasers can join an automatic subscription list to receive the summary update each year. The CD-ROM costs $30 and may be ordered online (www.iogcc.state.ok.us). Hardcopy in a three ring binder with state dividers costs $105 and may be ordered by calling IOGCC at 405-525-3556.

Deepwater Well Control Guidelines on CD-ROM

Deepwater well Control Guidelines by the International Association of Drilling Contractors are now available on CD-ROM. Developed for those drilling in deepwater, the guidelines focus on well planning, well control procedures, equipment and emergency response and training. Included with the guidelines are a 2000 supplement that covers unplanned disconnects in deepwater drilling, riser margin overview, external loading of BOP equipment and volumetric rating of subsea accumulator bottles. When purchased online (www.iadc.org), cost is $125.

Produced Water Life Cycle Cost

In a recent SPE paper and article, Shell International shared data from their analysis of produced water management. Operators know produced water is a major issue, but just how major. Overall average cost considering the total life cycle for Shell is $0.58 per barrel.

Components of that overall cost include: Pumping (28%), De-Oiling (21%), Lifting (17%), Separation (15%), Filtering (14%), Injecting (5%).

The above may seem high, but think about produced water’s "true" cost. Shell notes that an integrated approach is needed for individual fields, if not even wells (i.e., one size doesn’t fit all). Top priority is given to minimizing produced water volumes close to the source. Effective water management starts even with the drilling phase. Thorough understanding of reservoir geology, fluids and water entry points is required.

For that water which must be produced, one must look for ways to realize value. Waterflooding is a common example of realizing value through injection. Beyond injection, industry is working towards refining technologies for cleaning up water for other beneficial surface use.


Pollution-Free Power Plant of The Future

DOE Secretary Abraham recently announced plans for building a prototype of the fossil fuel power plant of the future, dubbed FutureGen. This one billion dollar venture will combine electricity and hydrogen production virtually eliminating harmful emissions, including greenhouse gases. DOE is asking the power industry to organize a consortium and provide at least 20% of the costs. Plans are for the plant to be built over the next five years, then operated for at least five years beyond that. The plant would be sized to generate about 275 megawatts of electricity, roughly equivalent to a mid-sized coal-fired power plant.

Carbon sequestration will be a primary feature that will set the prototype plant apart from other power plants. Carbon dioxide would be captured and sequestered in deep underground geologic formations, which in some cases might be in hydrocarbon reservoirs for additional recovery. The initial goal is to capture at least 90% of the plant’s carbon dioxide and even better capture may be feasible with technology advances.

Beyond operating virtually emission free, DOE anticipates that technology advances will significantly increase plant efficiency, as much as double conventional coal-burning power plants.

In a related effort, DOE and the Department of State outlined plans for creating the international "Carbon Sequestration Leadership Forum." The Forum will bring together ministerial-level representatives to discuss the growing body of research and emerging technologies for permanently isolating carbon dioxide and other greenhouse gases. An inaugural meeting is planned in Virginia during June.

For more information, see DOE’s techline www.netl.doe.gov/publications/press/2003/tl_futuregen1.html.

Regulatory Requirements for Drilling Waste Injection

PTAC CBM Conference
Proceedings Now Available

Proceedings from the 4th Annual Canadian Coalbed Methane Forum held last October in Calgary by the Petroleum Technology Alliance Canada (PTAC) are now available. The CD-ROM costs $200 Canadian. Proceedings for the 3rd conference are also available, costing $50 Canadian. To order, contact Brenda Belland, phone 403-218-7712, email bbelland@ptac.org.

PTAC is a Canadian not-for-profit association that facilitates collaborative research and technology development. It acts as a matchmaker between those that have problems or opportunities and those that have potential R&D solutions. PTAC brings stakeholders together to identify areas where R&D will make a difference, and to launch specific projects to address these problems or opportunities. PTAC promotes industry participation in the resulting R&D and assists with securing funding from a variety of sources. PTAC also facilitates the transfer of commercial technologies from other industrial sectors for application in the upstream oil and gas industry.

PTAC hosts three types of events—workshops, technology information sessions and forums/conferences. Workshops, which can be co-sponsored by other associations and government regulators, are utilized to clearly define industry challenges and opportunities. Technology Information Sessions are typically conducted by PTAC R&D supplier members with an industry or government regulator co-sponsor indicating the proposal or technology is "worthy of consideration." Forums/Conferences are conducted to communicate ongoing or completed research results. Visit PTAC's website (www.ptac.org) to learn more.

Drilling Well Classification System

The American Association of Petroleum Geologists and the American Petroleum Institute have agreed on a system, developed by Lahee in 1944, for classifying drilling wells. Such a system aids in clarifying the degree of technical, financial, and economic risk of a proposed well. Classifications, and concise explanations if needed, include:

- New Field Wildcat—far from producing fields and on a structure that has not previously produced. If structure doesn't control production, location would be at least 2 miles from productive area.
- New-Pool (Pay) Wildcat—new pools on structure already producing, or if structure doesn't control production, less than 2 miles from productive area.
- Deeper Pool (Pay) Test
- Shallower Pool (Pay) Test
- Outpost or Extension Test—usually two or more locations from nearest productive area.
- Development Well
- Stratigraphic Test—drilled without the intention of being completed as a producer.
- Service Well—observation, injection, water supply, etc.

Excerpted from article in Go Gulf Magazine, Jan/Feb 2003, p. 24-25.

Expandable Technologies, Spreading Quickly

Industry usage of Expandable Tubular Technology (ETT) is growing rapidly. Some have noted its potential impact might rank up there with 3-D seismic and horizontal drilling. After reading several recent articles on expandables, PTTC concurs with the assessment that expandables represent game-changing technology. So whether with a large or small operator, one might as well get on the learning curve.

In simple terms, the expandables process involves expanding steel by cold-working it downhole to the required diameter. Expandable technologies refer to both slotted and solid expandable tubulars, associated tools and accessories, and specialized systems used to expand the special pipe.

Expandables have a language unto themselves. One key term is EST (Expandable Slotted Tubulars). ESTs are pipes with staggered overlapping slots cut axially along the entire length. Expansion up to 200% of original diameter can be achieved. Main applications for ESTs are:

- Expandable Sand Screens (ESS™)
- Alternative Borehole Liners (ABL™)
- Expandable Completion Liners (ECL™)

Solid Tube Expansion (STE) requires much more force than ESTs (remember, that is Expandable Slotted Tubulars). On expansion, the tubular changes in thickness and length, altering the strength and burst capacity of the expanded pipe. There are numerous oilfield applications. STE technology can be used to:

1. create hangers and seals,
2. shut off unwanted perforations for water and gas,
3. strengthen existing corroded or worn casing and
4. retrofit corrosion resistance.

Expandable technologies are working towards a single-diameter wellbore, which would eliminate typical telescoping casing design. Shell, an early and continuing player, estimates that STE technology has the potential for reducing rig footprint by up to 75%, drilling muds by 20%, drill cuttings by 50% and cement by 50%. There are many targets from offshore to deep Rockies gas where expandables could be employed.


Petris Enhances Internet Data Room Product

Petris Technology unveiled its Version 3.0 of PetrisWINDS Internet Data Room at the North American Prospect Expo in Houston in January. Increased flexibility in this latest version enables users to quickly build their own Internet Data Room. Version 3.0 incorporates insights from Petris's three years experience with sellers, buyers and transaction advisers.

Product flexibility makes it useful for collaborative purposes beyond property transactions, including drilling and workover packages, internal asset team management, and sharing data with outside partners.

The new version uses the ARC/IMS map server from Environmental Systems Research Institute to provide map search capabilities. It can link to other Petris products and tools, including access to more than 50 E&P applications from Petris's ASP (Application Service Provider) service, PetrisWINDS NOW.

The system is available over the Internet on a monthly rental basis. Visit www.petris.com for an online demo of PetrisWINDS Internet Data Room.
Oxy helped design a system that helps prevent storm-generated power failures, using Schweitzer's SEL-701 relay and a special panel design, especially in the Permian Basin, where the company was experiencing load during upsets. Understanding that load is being as vulnerable as oilfield power systems, Oxy Permian’s driving force was to understand vulnerabilities of their field power systems and to reduce the failures so often experienced during electrical storms. Results from initial installations have prompted Oxy to conduct a system-wide optimization that is nearly 60-70% complete.

In looking at storm damage, Oxy was perplexed by residential power systems, especially subject to lightning, but that the lightning amplified problems during electrical storms. Results from initial installations have prompted Oxy to conduct a system-wide optimization that is nearly 60-70% complete.

Relays Reduce Field Power Distribution and Equipment Failures

Oxy Permian, one of the largest oil producers in Texas operating more than 6,000 wells in the Permian Basin alone, began installing relays developed by Schweitzer Engineering Laboratories in field environments in 1998. Oxy Permian’s driving force was to understand vulnerabilities of their field power systems and to reduce the failures so often experienced during electrical storms. Results from initial installations have prompted Oxy to conduct a system-wide optimization that is nearly 60-70% complete.

In looking at storm damage, Oxy was initially perplexed by residential power systems not being as vulnerable as oilfield power systems. Using relays, Oxy learned that what caused problems during electrical storms was not lightning, but that the lightning amplified existing problems. The source of the problem was that 99% of the load was induction motors that behave differently from residential load during upsets. Understanding that, they could then take appropriate action.

Electrical submersible pumps (ESPs) are one especially susceptible application. Every ESP shutdown can compromise equipment, potentially reducing pump life. Using Schweitzer’s SEL-701 relay and a special panel design, Oxy helped design a system that helps prevent motors from dropping off during brownouts or bumps. Eventually, the relay will tell the motor to turn off. Oxy is also planning to install the relay on beam-pumped wells, which would eliminate the load cell that sits on the rod. Eliminating the load cell will eliminate the bulk of the failures because of the fact that load cells on the rod strings frequently separate from the pump-off controller, causing hundreds of failures each year.


New Info Resource for Multilaterals

Estimates vary widely regarding how prevalent multilaterals are, ranging from 10% to 75% of the wells drilled each year depending on the source. A joint-industry project formed in 1997, Technical Advancement of Multilaterals (TAML), is known for its multilateral classification system. TAML believes that multilateral technologies, despite their increasing use, are still not being used to their full potential. So TAML will focus on education for the next several years.

With this new focus, TAML will educate the industry as a whole, from an industry perspective, as opposed to the vendor community perspective. TAML will develop and provide operators and vendors with standardized tender documents for bids. A standardized questionnaire will also allow operators to converse with vendors in language both sides understand. A selection guide will be another product. The purpose of TAML providing the information is analogous to an operator (a peer) making recommendations versus accepting those of a vendor with admitted bias.

Technology transfer plans include presentations, reservoir application data and short courses. There will be a strong web presence with a public section of TAML’s website (http://taml.altinex.no) containing case histories, technology and application updates, links, a bibliography, and more.


Wellbore Schematics Made EZ
e-VIPR, a web-based software package developed by WellEZ Information Management LLC, enables users to easily generate wellbore schematics. Users log onto the website and select the type of schematic to be constructed from an option page. This launches a
drawing tablet with appropriate associated tools and images. Schematics are constructed by selecting an object, which is then dragged onto the drawing tablet where it can be resized and positioned. Once complete, users can print or save as a pdf file. Data is stored on a central server, allowing multiple users to access the schematic. For further information, visit WellEZ’s website at www.wellez.com.

Ziff Energy Operating Cost/Benchmarking Studies

In February Ziff Energy began collecting data for its 4th Gulf Shelf Operating Cost Study. The study was last performed three years ago, assessing 1999 data. Participation is led by four of the largest Gulf operators, who collectively account for more than a third of Shelf production. The study focuses on operations in fields located in less than 1,000 feet of water and will analyze operating cost data for 2002. It will feature extensive trend analysis, both on a company and field level. Participants will receive confidential, blinded, asset-level cost comparisons versus comparable assets, as well as detailed analyses of cost drivers. Delivery is scheduled for June 2003. For more information, contact Ziff Energy Group, phone 713-627-8282.

Ziff recently completed a benchmarking study evaluating drilling costs and practices for gas wells in South Texas. The study analyzed about 400 wells drilled by 12 operators looking at drilling and completion cost data for 2001. Participants received a detailed diagnostic report on each well, comparing it with peer wells and identifying potential savings in each cost category. Key metrics included $/ft, ft/day and $/Mcfe/day. For shallow (less than 10,000 ft) normal-pressure wells, average drilling cost was $95/ft, but the “best in class” well cost $53/ft or 44% less than average. Leading drilling practices were identified via questionnaire to participants with Ziff then correlating specific practices to performance. Operators who did not participate in this study may do so on a “late” basis by contacting Richard Tucker; email rtucker@ziffenergy.com.

Data Mining For Prospect Location

Data mining and statistical techniques available to those looking for additional potential in existing fields/basins where there typically are massive amounts of data include visual data mining tools, cluster analysis, neural networks, decision trees and multiple regression. Data mining is a two-step process. First there is visual data mining to identify patterns of visual interest, followed by applying algorithms such as decision trees.

When facing massive amounts of data, in some areas from thousands of wells, the human brain is limited in what it can absorb unless other tools are used. That is where visualization enters in as a tool for discerning patterns. The use of different geometric shapes, size of data points and coloration are constructive tricks that help add dimensionality to data. Data miners can increase dimensionality, up to as many as six levels, until patterns are discernible.

In the work documented in the referenced articles, the authors mined data from more than 6,300 gas wells drilled in British Columbia, Canada during the last 30 years, examining some 15 independent variables against cumulative gas production (a high value being favorable). Free software, POV-Ray, which can be downloaded from www.povray.org, was used for plotting/visualizing the multi-dimensional day. POV-Ray can handle either scale or categorical data. Decision tree techniques along with certain cost/economic assumptions were further used to quantify results.

Considering economics, their analysis focused on predicting locations with cumulative production equal or greater than 3.392 Bcf. For 23 well targets, the chance of “finding” that volume or greater was between 94% and 100%. They also found a second group of 460 potential wells with a 63.1% to 66.6% chance of finding that volume or greater. What is the significance? The industry-wide median value for reaching that volume or greater is 14.9%. Data mining techniques provide explorationists with scarce time “high probability” locations where they can focus their effort.


Finalists for MMS’s 2002 SAFE Awards

Fifteen finalists have been selected in the Minerals Management Service’s (MMS’s) 2002 Safety Award For Excellence (SAFE) program. MMS presents annual awards in four categories to those who achieved the best safety and pollution prevention performance records.

High OCS activity—Dominion Exploration & Production, Inc., ExxonMobil Corporation, and Newfield Exploration Company.


Drilling Contractor—ENSCO Offshore Company, Rowan Drilling, and Transocean Offshore.


Winners will be announced in an April 29th recognition ceremony in Houston (www.mms.gov/awards/index.htm).

Produced Water Data Available Through KGS

The Kansas Geological Survey (KGS) makes an oilfield brine database available at www.kgs.ukans.edu/Magellan/Brine/index.html. The database has 3,785 samples with chemical analyses, of which 1,473 have water resistivity measurements. The database will soon be augmented to include estimated water resistivities for samples that have chemistry, but no water resistivity measurements. KGS has analyzed location of sample data (www.kgs.ukans.edu/PTTC/News/2003/q03-1-4.html) and is particularly soliciting data from areas with scant coverage. To explore submitting data, contact Dana Adkins-Heljeson, dana@kgs.ku.edu.

Illinois O&G Development Maps

O&G development maps for Illinois developed by the Illinois State Geological Survey are now available, costing $10.50 per map. Each map is approximately a 3x3 township grid and printed in three colors at a scale of 2”=1 mile. The maps also include major roads, towns, pipelines, and railroad tracks. Maps can be ordered by mail (Information Office, Illinois State Geological Survey, 615 E. Peabody, Champaign, IL 61820), phone 217-244-2414, or email isgs@isgs.uiuc.edu. Visa and MasterCard are accepted.
De-Watering Technologies Showcased
by Karl Lang

De-watering gas wells was the topic of a workshop held March 3-4 in Denver. Nearly 250 attendees listened to 33 presentations focused on various approaches to the problem of economically optimizing production from gas wells by minimizing the effects of liquid loading. The "Gas Well De-Watering Workshop" was organized and implemented by the Artificial Lift R&D Council (ALRDC), together with the American Society of Mechanical Engineers (ASME), the Southwestern Petroleum Short Course (SWPSC) and Texas Tech University - Dept. of Petroleum Engineering (TTU). While space limitations do not permit us to discuss all of the papers individually, we have selected three topics on which to comment from the wealth of excellent material presented. The complete list of papers is available at www.wellanalysis.com. Copies of the actual presentations, currently available online for attendees only, may be made available to the general public at a later date at a cost.

Plunger Lift with the Pacemaker Plunger

Plunger lift, a technology widely used to remove liquids from gas wells, was the subject of six papers. Two of these dealt with the Pacemaker plunger, a new approach to this traditional method of artificial lift. Traditional plunger lift requires shut-in time for the plunger to fall back to the bottom of the tubing and then for the buildup of pressure to drive the plunger back to the surface. This shut-in time results both in lost production and in the forcing of liquids back into the formation. The Pacemaker plunger operates as two interdependent pieces (a piston and a ball), each of which fall separately and are designed to do so against a significant rate of upward gas flow (Figure 1). Once on bottom, the ball seals off in a cavity in the piston.

Once the gas flow has driven both back to the surface a rod in the lubricator separates the ball from the piston, enabling the next cycle to begin. The result is that only 5-10 seconds of shut-in time per cycle is required and liquids are not forced back into the formation.

A presentation by ChevronTexaco's Robert Lestz described the results of Pacemaker installations in a variety of Texas locations. In West Texas, a group of ten wells showed a total increment of 1200 Mcfd after conversion to the Pacemaker plunger (Figure 2). Eight of these wells were converted from standard plungers and two had been converted from flowing. East and South Texas examples showed even more dramatic results, with some wells showing more than 200% improvement in gas flow rate after installation of the Pacemaker plunger. In cases where soap was being used to improve liquid lifting there were also substantial savings in monthly chemical costs.

ChevronTexaco has employed the Pacemaker in a wide variety of well configurations, including: tubing packer completions, open ended tubing, monobore completions (no annulus), and as a replacement for capillary strings and standard plunger lift. These applications have been in sandy environments, in conjunction with single well compression, and even on both sides of a dual completion.

The primary benefit recognized by Lestz is the fact that there is practically no shut-in time. This minimizes production fluctuations and means less interference for wells sharing the same facilities or...
compression. The longer flow period means more production and production is not squeezed back into the formation. Stabilized production makes reservoir analysis possible.

There are some limitations with this technology. It works best with low line pressure and at gas rates below ~150-200 Mcf/d at FTP~ 80+ psia. Very high liquid rates impede the ability of the ball to fall and some problems can be presented if the tubing is set too high, if there are shallow restrictions such as nipples in the tubing string, or if sand production is excessive. Finally, and this is true for any new technology, people must understand that the critical parameters are different than those for a conventional plunger lift installation and be trained to properly set the controller, troubleshoot and optimize. For vendor information go to www.mgmwell service.com

Gas Auger

Marathon presented the results of their "gas auger" in the Indian Basin field of Eddy County, New Mexico. The gas auger was developed to combat operational difficulties associated with producing free gas with submersible pumping equipment. The primary productive interval at Indian Basin is the U. Pennsylvanian Canyon & Cisco at a depth of 7500’. The reservoir consists of 400-600’ of carbonate. There is 6500 ppm H2S in the produced fluids.

Historically, wells in this field exhibit a dramatic increase in water production and an associated sharp decrease in gas production when they start to water out. Many wells flow 3-4 MMcf/d before the water encroachment and continue to flow 1-2 MMcf/d with only 100-200 Bwpd afterwards. Subsurface electrical pumps are used to produce the wells.

Gas interference is a problem with ESPs for a number of reasons: poor cooling qualities, diminished efficiency and down time. Because gas is produced up the casing-tubing annulus Marathon is forced to run shrouded units and land the pump intakes below the bottom perforations. When gas is the cooling medium between the shroud and motor the motors see higher temperatures and this shortens the life of the motors and seal components. In the case of some wells the problem was so severe that it was nearly impossible to keep the pumps running much less achieve optimum drawdown. Free gas greatly diminishes pump efficiency. This decreased efficiency means extra HP and more pump stages are required to "pump" the gas. Down time associated with underloads also results from gas interference, leading to lost production. Also, as the gas passes through the pumps the stages, seal, and motor can go into upthrust. This can destroy pump stages over time and can lead to sudden failure in the seal section.

Marathon tried a number of conventional approaches to dealing with this problem, including shrouds, rotary gas separators, gas anchors, tapered ESP’s, and others, before developing the gas auger. The gas auger consists of a section of concentric tubing coupled with a series of external blades that are run below the perforated interval. The blades facilitate the separation of gas from the liquid and the concentric tubing string enables the gas to bypass the ESP more efficiently (Figure 3).

Augers have been installed in 13 wells to date: Ten 7" models and three 9 5/8" models. Before and after tubing tests indicate a 75% separation efficiency. Marathon has successfully pulled and rerun 8 auger assemblies (and made some improvements to the installation/pulling procedure along the way). Total BOEPD increase for auger installations is 3393 BOEPD, excluding proactive installations in new drill wells. On two wells, incremental production has totaled 1900 BOEPD from a $16,000 investment. On those two wells alone Marathon recognized savings of $3200/month from decreased HP requirements. The savings from decreased failure frequency is yet to be determined but could be significant.

Figure 2—Pacemaker Field Test Normalized Production from All Wells
Chemical Treatments

Chemical treatments have been used to combat liquid loading in gas wells, along with scaling and/or salting problems, for many years. Chemical foaming is used to lighten the hydrostatic load, enabling the water to be lifted out by gas pressure. James Archer of Multi-Chem Group, LLC out of Sonora, TX presented a paper that outlined the critical parameters that should be analyzed before a decision is made to employ, or not to employ, chemical foaming additives.

Application of foaming chemicals has progressed from batch treatments to constant application via concentric capillary tubing. By allowing the chemical injection to take place at the bottom of a well, other problems such as scaling can also be treated. Evaluating the well is crucial to the solution. Selection of a foaming agent is dependent upon condensate ratio, required foam quality and bubble size, presence or lack of an emulsion, and water chemistry. Testing of live fluids is necessary, particularly if additional chemical components are to be included to help prevent corrosion, scale, and salt deposition.

Archer provided three case histories of successful chemical de-watering. The first, a Wilcox well in Webb County, Texas, was producing up tubing at 450 psig making 5 barrels of total fluid per day but not responding well to foaming agents. Sampling and analysis showed that the well was actually producing about 25 to 30% condensate. The well was subsequently batch treated with 5 gallons H₂O, and 7 gallons foaming agent, down tubing and casing. An injection pump was then used to pump 8 gallons per day of the selected foaming agent until the well unloaded. Well went from 90 mcf to 400 mcf/d. The pump rate was reduced to 2 gallons per day and a rate of 375 to 400 mcf/d was maintained.

A Cotton Valley well in Bienville, Louisiana was flowing up tubing under a packer at 50 mcf/d and had to be routinely shut in for pressure buildup and intermittently blown to a tank to unload, losing 2 to 3 days production per week. After analysis, the tubing was perforated just above packer and a foaming agent injected in a 40% solution with 2% KCL water at a rate of 15 gallons per day. Within two days after the foamer was started, the rate was up to 385 mcf/d. The injection rate was cut back to 8 gallons per day, while the gas rate continued to climb to 1200 mcf/d.

A Wilcox well in DeWitt Co., Texas produced 120 mcf/d, 6 barrels of condensate and 8 barrels of brine per day but became plugged with salt every 2 weeks and had to be treated with fresh water and shut-in for two days in order to return production. After analysis, a continuous injection of a 20% solution of foamer in fresh water down hole through a ¼” capillary string was established at a rate of 1.5 barrels per day. The well responded with a production increase to 720 mcf/d. Four months later, it continued to produce approximately 720 mcf/d while salting has been non-existent. The variance in production fluids, condensate ratios, and water make-up, causes various foaming agents to act with varying results. Where complete studies of water, foam testing, and evaluation of fluid dynamics have been conducted, favorable results can be achieved. Using foaming agents to enhance gas well production provides a very cost-effective lift method, often greater than a 6:1 return on investment in equipment and chemicals.

Figure 3—Gas Auger Installation

Author: Karl Lang, HART Publications. For further information, contact Lance Cole at lcole@ptc.org.
Technology Advances Result From DOE Class II Projects

Back in 1994, nine DOE-supported cost-shared field demo projects began in Class II Shallow Shelf Carbonate reservoirs. Later on in 2000, an additional six projects were funded within DOE’s Class Revisit program. By now the nine original projects have been finished, while work is still ongoing in the six Class Revisit projects. Projects are located in Alabama, Colorado, Kansas, the Michigan Basin, Oklahoma, Texas, Utah, and the Williston Basin. Last December project performers gathered in Midland, Texas to share what has been learned through the projects. DOE has summarized insights in its latest Class Act newsletter (Volume 9/1, Winter 2003), available online at www.nptd.doe.gov/CA/CAWin2003.pdf.

Highlights from a couple of projects follow.

Recovery of Williston Basin Carbonates, Luff Exploration Company. In the initial Class project, Luff Exploration demonstrated how seismic attribute analysis could be used to characterize Red River/Ratcliff targets. It was discovered that drilling on the flanks of structural features where porosity was better developed resulted in improved wells as compared to conventional wells located on top of the structure. Horizontal re-entry completions proved to be an effective completion option. One demo site demonstrated waterflooding using horizontal injectors. In the later Class Revisit project, an Intelligent Computing System using neural networks and fuzzy logic for reservoir analysis and risk assessment was developed. The ICS tool was used in the Amor Field to select sites for horizontal wells in small structural features. Plugged or uneconomic vertical wells were re-entered and drilled horizontally. Drilling in similar projects using the ICS tool is planned during 2003 and 2004. The ICS tool kit and instructions may be downloaded at no charge from www.luffdoeproject.com. Project contact, Mark Sipple, Mark Sipple Engineering, phone 303-864-9734, email msipple@ix.net-com.com.

Optimizing Reservoir Performance in the Hunton Formation, Oklahoma, The University of Tulsa (TU). In the West Carney field, Hunton oil wells initially produce at a very high water cut but, as oil and high volumes of water are produced, the water cut decreases. This behavior has been termed retrograde oil cut. As the water/oil ratio decreases over time, the gas/oil ratio first increases then decreases with time. This unique behavior led to rapid development of many Hunton wells in Oklahoma. To better understand the why and how, and to determine what other reservoirs might be amenable to this production process, the project team performed detailed reservoir characterization, including analyzing 27 cores, log analysis, flow simulation and rate-time analysis of production data. Data indicate that the aquifer is limited, and water rate and pressure are declining as the field is produced. However, the bulk of hydrocarbon production is through the water zone and dependent on it, such that wells that produce less water produce less oil. Two workshops with an intriguing title, Dewatering of the Hunton Reservoir in West Carney Field - Mystery Solved?, are scheduled, April 16 in Tulsa and April 21 in Oklahoma City. For information about these workshops, contact Lori Watts, phone 918-631-2979, email lori-watts@utulsa.edu.

Carbon Fiber Drill Pipe Used in Short-Radius Horizontal Re-Entries

Early in 2003, Grand Resources Inc., Oklahoma, used 2 5/8-inch OD composite carbon fiber drill pipe with 3 1/8-inch heat-treated steel tool joints to drill short 70-ft radius build portions in two horizontal re-entries. These re-entries in 5 1/2-inch casing were in 1,300 ft vertical wells in the Bird Creek Field in Tulsa County, Oklahoma. The wells were originally completed in the 1920s. The pipe performed favorably in the first well, but the second well encountered problems with the tool joint connections that the manufacturer is addressing. After drilling a short portion of the horizontal legs, 30 ft and 60 feet in the two wells, the remainder of the laterals was drilled with standard steel drill pipe. The first well is now producing 12-15 bpd while completion is in progress in the second well. Grand Resources will be using the composite drill pipe in additional horizontal well bores in the coming months.

Advanced Composite Products and Technology, Inc., Huntington Beach, California, developed the composite carbon fiber pipe in a DOE-supported project. It is expected to be commercially available by summer. Field testing of a larger 5 1/2-inch OD pipe is planned this spring. Although more expensive than steel drill pipe, the composite pipe has a big advantage. It can remain bent for extended periods of time while rotating without suffering fatigue, making it particularly well suited for short-radius horizontal applications. Plus it is much lighter, weighing about half as much as steel pipe.

Produced Water Treating Method Impacts CBM Recovery in Powder River Basin

DOE released a study, Powder River Basin Coalbed Methane Development and Produced Water Management, late last year. The study, performed by Advanced Resources International, found that 29 Tcf could be economically produced with surface water disposal, the current prevalent practice. Requiring that water be re-injected into shallow fresh water zones would reduce recovery to 27 Tcf, while requiring treatment by reverse osmosis would further reduce recovery to 18 to 22 Tcf.

The study’s 39 TCF estimate of technically-recoverable reserves is among the highest of a range of resource estimates. For reference, proven gas reserves in the lower 48 states is estimated at just over 180 Tcf. The study also concluded that future development will require fewer wells than previously estimated.

For more information, visit DOE’s NETL website (www.netl.doe.gov/publications/press/2002/tl_cbm_powderriver.html) or contact John Duda, DOE NETL, phone 304-285-4217, email jduda@netl.doe.gov.

Four More Awards in DOE’s Independents Program

In January DOE announced the four most recent project awards in its Technology Development with Independents program. In this program, small independents (up to 50 employees) can receive awards up to $100,000. 50% cost share is required.

Vecta Exploration, Inc. (Texas) will complete a shear wave seismic study documenting the imaging quality, costs, and potential benefits of combining S-wave and P-wave seismic data. Conventional 3-D seismic survey methods today use only compressional (P) waves,
which generally works well for identifying structural features. However, successful drilling depends not only on structure, but on locating rock fractures, detecting porosity trends, and locating subtle areas of trapped oil. Combining S-wave with P-wave data provides a more complete geologic "picture."

St. James Oil Corporation (California) will use a new hydrochloric-phosphonic acid solution to restore oil production in shut-in wells in the Las Cienegas Field in Los Angeles. When shut down for more than a year, reactivated wells in this field typically produce 30 to 50 percent less than prior to shut down due to calcium carbonate scale buildup. The phosphonic acid reacts with minerals in the rock to form a temporary protective film, allowing deeper penetration and more effective reaction from the hydrochloric acid, inhibiting and reducing the formation of additional calcium carbonate scale.

Crystal River Oil and Gas LLC (California) will test a new polymer gel treatment process for water shut-off in oil wells in the Alameda Field in Kingman County, Kansas. The new polymer gel is comprised of two chemicals: a powdered polyacrylamide polymer, which is a strengthening agent, and chromic acetate. Together they form a high strength thickened gel that will be pumped under high pressure into the selected wells. Each well will be left idle for 3-4 days, after which the wells will be returned to production.

Team Energy LLC (Illinois) will test the feasibility of using specially designed instrumentation to control well pumping operations to limit salt water production. Two types of instrumentation, a fluid density meter and an inductive electrical conductivity meter, will be used simultaneously. Since the density and electrical conductivity properties differ between oil and water, the instrumentation should be able to detect which fluid is in the produced stream. The pump will be shut down when water is detected. Performance will be evaluated in two active pumping wells, one idle well, and one flowing well in the Illinois Basin in Posey County, Indiana.

Stripper Well Consortium Proposals Due April 18

Those seeking funding from the DOE-supported Stripper Well Consortium (SWC) during 2003 must submit abbreviated written proposals by April 18, plus present their proposal orally to the SWC in its spring meeting on May 5-6. Proposals are accepted only from Full Members (membership fee may be enclosed with proposal) and require 30% cost share. Period of performance for those winning awards is July 1, 2003 to June 30, 2004. To see the diversity of topics being explored within the SWC, review projects awarded last spring. Information is posted on the SWC website (www.energy.psu.edu/swc/projectoverview.shtml).

DOE Makes 10 Awards in its PRIME Program

On March 11, DOE announced 10 awards for research within its PRIME Program. PRIME (Public Resources Invested in Management and Extraction) differs from DOE’s other oil technology R&D programs in that it stresses high-risk research on concepts that may require five to 10 years to develop. A major goal is to develop new approaches that can lead to enhanced production of oil resources on public lands.

Total cost of the 10 projects is $11.8 million with DOE providing $8.7 million or 74% of the funds and the performers the remainder. The projects are located in Alabama, California, Mississippi, Oklahoma, Texas, Utah and Wyoming. Topics span a range of exploratory research efforts. Awards were made in three areas.

Area 1 - Oil and Gas Recovery Technology

Stanford University: Experimental Investigation and High Resolution Simulator of In-Situ Combustion Processes

Rice University: Surfactant-Based Enhanced Recovery Processes and Foam Mobility Control

University of Southern Mississippi: Smart, Multifunctional Polymers

University of Wyoming: Fundamentals of Reservoir Surface Energy as Related to Surface Properties, Wettability, Capillary Action and Oil Recovery from Fractured Reservoirs by Spontaneous Imbibition

Area 2 - Drilling, Completion and Stimulation

Terra Tek, Inc.: Smaller Footprint Drilling System for Deep and Hard Rock Environment; Feasibility of Ultra-High Speed Diamond Drilling

The University of Texas at Austin, Petroleum & Geosystems Engineering Department: A Comprehensive Statistically-Based Method to Interpret Real-Time Flowing Well Measurements

University of Tulsa: Development of Next Generation Multiphase Pipe Flow Prediction Tools

Area 3 - Advanced Diagnostic and Imaging Systems and Reservoir Characterization

University of Alabama: Basin Analysis and Petroleum System Characterization and Modeling, Interior Salt Basins, Central and Eastern Gulf of Mexico

The University of Texas at Austin, Bureau of Economic Geology: Elastic Wave Field Stratigraphy - A New Seismic Imaging Technology

Texas Engineering Experiment Station, Texas A&M University: Intercell Connectivity and Diagnostic Using Correlation of Production and Injection Rate Data in Hydrocarbon Production

DOE's tech line (www.fossil.energy.gov/techline/tl_prime_sel03.shtml) provides further details on the individual projects.

Alaskan Methane Hydrate Research Well to Demonstrate New Arctic Drilling Platform

Hot Ice 1, a dedicated methane hydrate research well, was spudded in the Alaskan North Slope in March. An industry team of Maurer Technology, Inc., Anadarko Petroleum Corporation and Noble Engineering and Development led the effort in the 3-year, $10+ million cost-shared cooperative agreement with DOE. Obviously, the primary focus is to gather data on methane hydrate occurrence and production, but the research well will also demonstrate a new Arctic Drilling Platform, patented by Anadarko and constructed in Houston. This new drilling platform allows for an extended drilling and testing season, from three or four months to eight or nine months.

The new platform consists of 16 aluminum pieces with legs that screw into the soil. Because of the screw design, they don't have to be as deep as pilings. It is light enough to be transported by helicopter or a large all-terrain vehicle and assembled on site. Gravel roads and pads, which can leave long-lasting scars, aren't needed. It sits 12 feet off the ground, high enough that animals don't have to go around it. It can be used for exploratory drilling and for production. It is big enough to hold a drilling rig and auxiliary equipment.

Regardless of the outcome of Hot Ice 1, there are other applications for the platform. For more information contact the project’s principal investigator, Tom Williams, email twilliams@noblecorp.com, with Maurer Technology.
Applied Digital Subsurface Mapping

April 18-19, 2002 (Mt. Carmel, IL)
by PTTC’s Midwest Region

BOTTOM LINE
The University of Illinois has concentrated on improved methods of digital mapping, including Trend Analysis and 3-D Modeling. Trend Analysis is based on a method for differentiating regional and local components in a map area. Three-dimensional modeling provides a tool for visualization of the spatial distribution of data collected by geologic, geophysical, petrophysical and engineering means. An example of trend analysis would be to describe an anticline as a local anomaly occurring along a regional dipping surface.

PROBLEM ADDRESSED
Petroleum exploration depends on identification of anomalies between regional and local components in a map area. Trend analysis provides a tool for efficient discrimination and 3-D modeling is the best means for visualization of the data.

2002 Rockies Coalbed Methane Symposium

June 19, 2002 (Denver, CO)
co-sponsored by PTTC’s Rocky Mountain Region, The Rocky Mountain Association of Geologists (RMAG) and Gas Technology Institute (GTI)

BOTTOM LINE
Coal-bearing basins in the United States are in competition for frontier coalbed methane (CBM) resources. Acreage position and knowledge of the best geological and engineering methods for evaluation and developing CBM resources are needed.

PROBLEM ADDRESSED
CBM plays in the San Juan, Powder River, Raton and Uinta basins are maturing, and lessons learned in these basins are not necessarily applicable for new plays and other basins. The goal of the 2002 CBM Symposium was to explore all the existing and emerging technologies and focus on how to apply them to new CBM plays, such as in British Columbia and eastern Kansas. The number of participating companies, sponsors and exhibitors indicate the high interest in CBM exploration and development.

Improving Oil Recovery Using Integrated Evaluation Techniques

April 23, 2002 (Wichita, KS)
by PTTC’s North Midcontinent Region

BOTTOM LINE
The Kansas Geological Survey has developed new technologies and strategies to improve oil recovery from Kansas oil fields. The focus has been to provide increased access to public data through online digital programs, development of log analysis software, improved reservoir characterization, modeling and computer simulations.

PROBLEM ADDRESSED
The Kansas Geological Survey (KGS) carries a responsibility to the independent operators in Kansas to provide data and advanced evaluation and interpretation techniques for hydrocarbon exploration and production. Individual operators do not have the facilities or manpower to accumulate and access all the public data collected by the state of Kansas. KGS researchers are able to improve means of access to data, and demonstrate new technologies and best practices through development of software, methodologies and case studies applicable to Kansas oil fields.

Produced Water

Dec. 4-5, 2002 (Farmington, NM)
by PTTC’s Southwest Region

BOTTOM LINE
To increase well/lease profitability, producers should implement a strategy to reduce excessive water production. Industry has developed proven practices for determining if there really is a problem, correctly diagnosing it and finding the appropriate solution. Solutions can range from the simple mechanical to chemical such as polymer gels. With proper application and operator/provider cooperation, success rates with polymer gels can exceed 90%. Industry increasingly is looking for ways to treat produced water for beneficial use, but much R&D remains to be done.

PROBLEM ADDRESSED
On average in the U.S., for every barrel of oil produced, there are some 8-9 barrels of water produced. This high volume of produced water significantly increases power consumption and operating costs and can cause environmental problems. Operators are constantly searching for improved technologies to manage the produced water issue, including even treating it for beneficial use.
1st Quarter 2003 Case Studies
Petroleum Technology Digest

Polylined tubing reduces downhole failures

Bottom Line: Field results in the past few years have proven that using polyliners can increase uptime and save money—even over plastic coatings. Many operators are using polylined tubing to reduce well failures from rod-tubing wear and tubing corrosion in artificial lift and injection wells. BP America, ChevronTexaco, Conoco and Fasken Oil and Ranch have used polylined tubulars in over 41 wells with substantial savings in operating costs.

Using capillary strings to unload gas wells and increase production

Bottom Line: ChevronTexaco has successfully employed capillary strings in South and East Texas to resolve problems associated with liquid loading. ChevronTexaco now has more than 100 installations. Detailed analysis of the initial 17 installations in South Texas revealed a 74% success rate. Installation costs, which can approach $15,000, will pay out in less than three months with representative gas prices and production increases (100 mcfd).

Reverse circulation drilling avoids damage to low-pressure gas reservoirs

Bottom Line: PressSol Ltd. of Calgary has adapted reverse-circulation, center-discharge drilling (RCCD) for oil and gas drilling. Because RCCD drilling returns cuttings through the ID of the inner portion of double-wall drill pipe, it does not expose the formation to possible damage from drilling fluid and, thus, is particularly well suited for drilling low-pressure reservoirs. K2 Energy of Calgary has applied RCCD to successfully drill and test gas wells in the low-pressure (formation pressure estimated at 150 psi) Bow Island formation on the Blackfeet Indian Reservation in northern Montana. As of February 1, 2003, the system has been used to drill 11 Bow Island wells on the reservation and an additional five wells in the Thrust Belt. Drilling cost is competitive with mud or air drilling in that area; $15/ft for fluid string to 600 ft and $10/ft for a long string to 2,500 ft. The system can be adapted to any rig with the addition of a dual-wall drillstring.

Water Reduction Through Polymer Treatments

Recognized industry speakers in Jan. 22 Workshop in California. From Left to right—J. Portwood and Jim Mack, Tiorco Inc.; Ralph Cook, moderator, Enhanced Petroleum Tech, Inc; Iraj Ershaghi, PTTC West Coast; Rich Pancake, Univ. of Kansas Tertiary Oil Recovery Project; Bob Sydansk, Petroleum Recovery Research Center at New Mexico Tech.

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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.

April 2003

4/3 South Midcontinent: Joint Operating Agreements (Marginal Well Commission) - Enid, OK. Contact: 405-604-0460
4/10 South Midcontinent: Joint Operating Agreements (Marginal Well Commission) - Oklahoma City, OK. Contact: 405-604-0460
4/11 Texas: Structure and Stratigraphy of South Texas and Northeast Mexico, Applications to Exploration (South Texas Geological Society, Gulf Coast SEM) - San Antonio, TX. Contact: 512-471-0320
4/15 Texas: Well Cuttings - Houston, TX. Contact: 512-471-0320
4/16-17 Rocky Mountain: Rocky Mountain Energy Technology Conference (Independent Petroleum Association of Mountain States, Gas Technology Institute) - Denver, CO. Contact: 303-623-0987
4/17 South Midcontinent: Joint Operating Agreements (Marginal Well Commission) - Tulsa, OK. Contact: 405-604-0460
4/17 West Coast: Operating Cost Reduction, A Roundtable Discussion - Los Angeles, CA. Contact: 213-740-8076
4/18 Rocky Mountain: Crash Course in Log Analysis (Independent Petroleum Association of Mountain States, Gas Technology Institute-following Energy Technology Conference) - Denver, CO. Contact: 303-273-3107
4/22 Appalachian: Well Safety - Prestonburg, KY. Contact: 304-293-2867 ext 5415
4/23 Central Gulf/Texas: Hydraulic Fracturing - Shreveport, LA. Contact: 225-578-1804
4/24 South Midcontinent: Joint Operating Agreements (Marginal Well Commission) - Ada, OK. Contact: 405-604-0460
4/24 Appalachian: Well Safety - Buckhannon, WV. Contact: 304-293-2867 ext 5415

May 2003

5/5-9 Eastern Gulf: International Coalbed Methane Symposium (other sponsors) - Tuscaloosa, AL. Contact: Ed Martin, phone 205-348-1792 or Email emartin@ccs.ua.edu
5/7 Eastern Gulf: Paraffin/Asphaltene Control - Jackson, MS. Contact: 205-348-4319
5/8 South Midcontinent: Trade Fair (Marginal Well Commission) - Oklahoma City, OK. Contact: 405-604-0460
5/10 Rocky Mountain: Desktop Applications—Excel, Access, Database Fundamentals (AAPG annual meeting) - Salt Lake City, UT. www.aapg.org
5/11 Rocky Mountain: Complex Well Technology for Earth Scientists and Engineers (AAPG Annual meeting) - Salt Lake City, UT. www.aapg.org
5/11 Rocky Mountain: Desktop Applications-PowerPoint and Effective Graphics (AAPG annual meeting) - Salt Lake City, UT. www.aapg.org
5/11 Rocky Mountain: Subsurface Fluid Pressures and Their Relation to Oil and Gas Generation, Migration and Accumulation (AAPG annual meeting - Salt Lake City, UT. www.aapg.org
5/19-23 Southwest (workshop & field trip): Mesa Verde - Albuquerque, NM. Contact: 505-835-5685
5/22 West Coast: Independents Day @ SPE/AAPG Western Regional Meeting - Long Beach, CA. Contact: 213-740-8076

June 2003

6/10 Rocky Mountain: Coalbed Methane Symposium (Rocky Mountain Association of Geologists) - Denver, CO. Contact: 303-273-3107
6/11-14 Rocky Mountain (field course): Coal Stratigraphy (Rocky Mountain Association of Geologists) - Rock Springs, WY. Contact: 303-273-3107
6/19-20 South Midcontinent: Interpreting Reservoir Architecture Scale Frequency Phenomena (Oklahoma Geological Survey) - Oklahoma City, OK. Contact: 405-323-3031
6/22-27 Rocky Mountain: Futures in Energy (student internship program) - Golden, CO. Contact: 303-273-3107
6/22-27 West Coast: COMET 2003 (student internship program) - Los Angeles, CA. Contact: 213-740-8076
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