the ENERGY lab

E&P Focus

Fall 2009 Oil & Natural Gas Program Newsletter

NETL

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U.S. DEPARTMENT OF ENERGY

Southern Alabama CO_2 EOR Project to Begin Production Soon

Citronelle Dome is a giant salt-cored anticline in the eastern Mississippi Interior Salt Basin of Southwest Alabama near Mobile. The Citronelle oil field, which is on the crest of the dome, has produced more than 168 MMbbl of 42-46° gravity oil from fluvial sandstones (Donovan Sands) in the Lower Cretaceous Rodessa Formation (Figure 1). The field has been water-flooded for a number of years.

Approximately 37 percent of the original oil in place in the Citronelle field has been recovered by primary and secondary methods. A project jointly funded by NETL, with partners Denbury Resources Inc. (the owner and operator of the Citronelle oil field), the Southern Company, the Geological Survey of Alabama, the University of Alabama, Alabama A&M University and the University of North Carolina at Charlotte, will attempt to increase that recovery percentage through the application of CO_2 enhanced oil recovery (EOR). It has been estimated that up to 64 million bbl of additional oil could be recovered using this technique. CO_2 EOR will also significantly extend the life of the field, securing jobs in the field and creating new employment opportunities in the area.

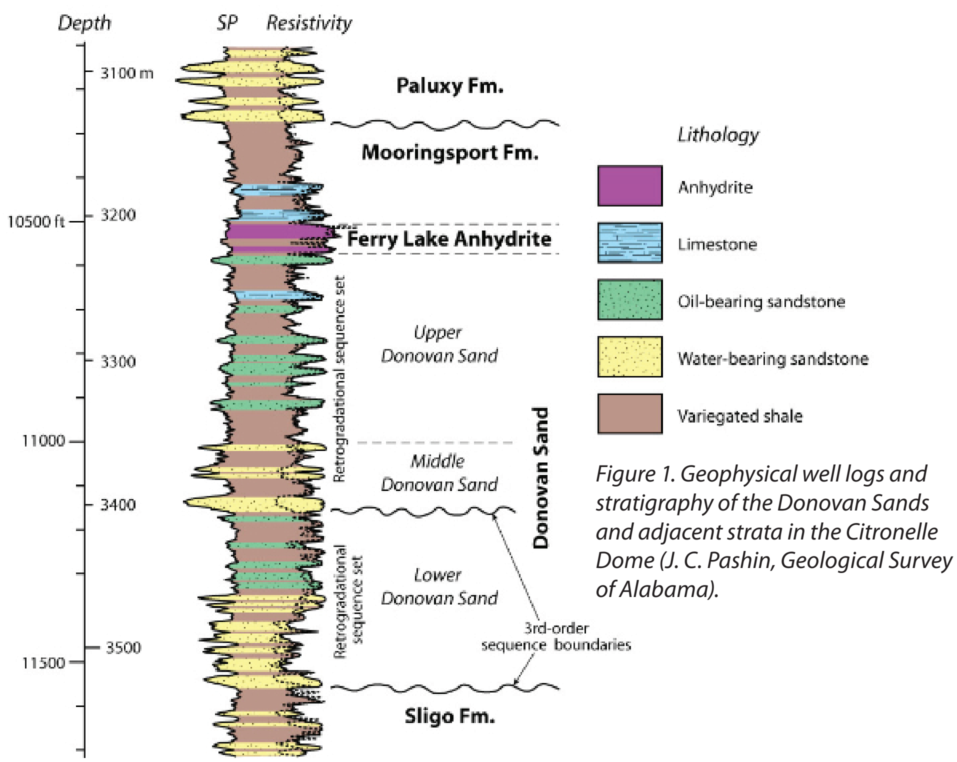

Figure 1. Geophysical well logs and stratigraphy of the Donovan Sands and adjacent strata in the Citronelle Dome (J. C. Pashin, Geological Survey of Alabama).

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Commentary

As we are all aware, the global community must make every effort to realize a sustainable energy future. Getting there will require discipline and sufficient resources, including a reasonable transition timeline. In the interim, our current fuel mix will continue to underpin the global economy. The Energy Information Administration's Annual Energy Outlook 2009 estimates that liquid fuel, primarily oil, will provide 37 percent of the world's energy this year. The report estimates that, in 2030, liquids will comprise 34 percent of the world's fuel mix. We cannot escape the fact that oil is an important transition fuel to the future global fuel mix. That is why the National Energy Technology Laboratory's Strategic Center for Natural Gas and Oil (SCNGO) is funding numerous research and development projects to increase domestic oil production and address environmental concerns related to oil (and natural gas) exploration and development.

Our oil research and development program addresses a wide gamut of needs, from cost-effective technologies for America's small operators to cutting edge technologies that will allow us to drill for and produce oil in waters over 10,000 feet deep. Between these two "book ends" we are actively working to enhance a variety of technologies, such as carbon dioxide (CO_2) enhanced oil recovery and more effective methods to recover oil from unconventional sources such as heavy oil deposits or oil bearing shales. In this issue of *E&P Focus*, you will find a number of articles detailing some of the exciting NETL R&D efforts focused on increasing domestic oil production.

All the research and development we undertake is bounded by our commitment to make oil (and natural gas) exploration and development a more environmentally friendly process in addition to supporting overarching climate change and energy security goals .

In line with the comments above, I am pleased to announce the publication of a new NETL primer, *Carbon Dioxide Enhanced Oil Recovery: Untapped Domestic Energy Supply and Long Term Carbon Storage Solution*. In it you will find basic explanations of a technology that would allow the U.S. to pursue the recovery of 85 billion barrels of domestic oil. You will also find a discussion of the potential for CO_2 enhanced oil recovery to serve as a mechanism for long-term storage of anthropogenic CO_2. You can obtain a copy of the new primer on the NETL Web site.

John R. Duda
Director, NETL Strategic Center for Natural Gas and Oil

The $6 million Citronelle CO_2 EOR project began in 2007. The project is divided into three phases, each of 20 months duration. The research in Phase I, completed August 31, 2008, focused on selection of a test site, detailed study of its geology, determination of oil-CO_2 minimum miscibility pressure, simulation of CO_2 EOR performance, and the establishment of environmental background conditions at the site. The focus in Phase II (currently underway and extending to April 30, 2010) is on the first CO_2 injection (7500 tons) and the associated measurements and monitoring. The focus in Phase III (May 1, 2010 to December 31, 2011) will be on the injection of a second 7500 ton slug of CO_2 and a comprehensive evaluation of the results from both injection tests.

Preparation for the first injection of CO_2 is complete. The geology, petrology, and stratigraphy of the Rodessa Formation in the vicinity of the test site have been determined and documented at an unprecedented level of detail; realistic and informative reservoir simulations have been performed; the environmental and ecological background conditions surrounding the site have been measured; the minimum miscibility pressure and absence of precipitation from oil in the presence of CO_2 have been established; and a favorable economic analysis was conducted that identifies the optimum CO_2 slug size for water-alternating-gas oil recovery under specified CO_2 cost and oil price constraints. All indications are that the pilot test will provide an unequivocal demonstration of carbon-dioxide-enhanced oil recovery and essential data and simulations on which to base a commercial CO_2 flood in the Citronelle Field.

All geophysical logs from wells in a 4-square-mile area surrounding the test site were digitized and used to construct a network of nineteen stratigraphic cross sections correlating Sands 12 through 20A in the Upper Donovan Sand (Figure 2). The cross sections demonstrate the extreme facies heterogeneity of the Upper Donovan, well expressed within the five-spot well pattern chosen for the pilot test. Detailed study of the petrology and sedimentology of Citronelle well cores has shown that depositional environments in the Rodessa Formation differ significantly from the model developed in early published work that guided past development and production from the Citronelle Field.

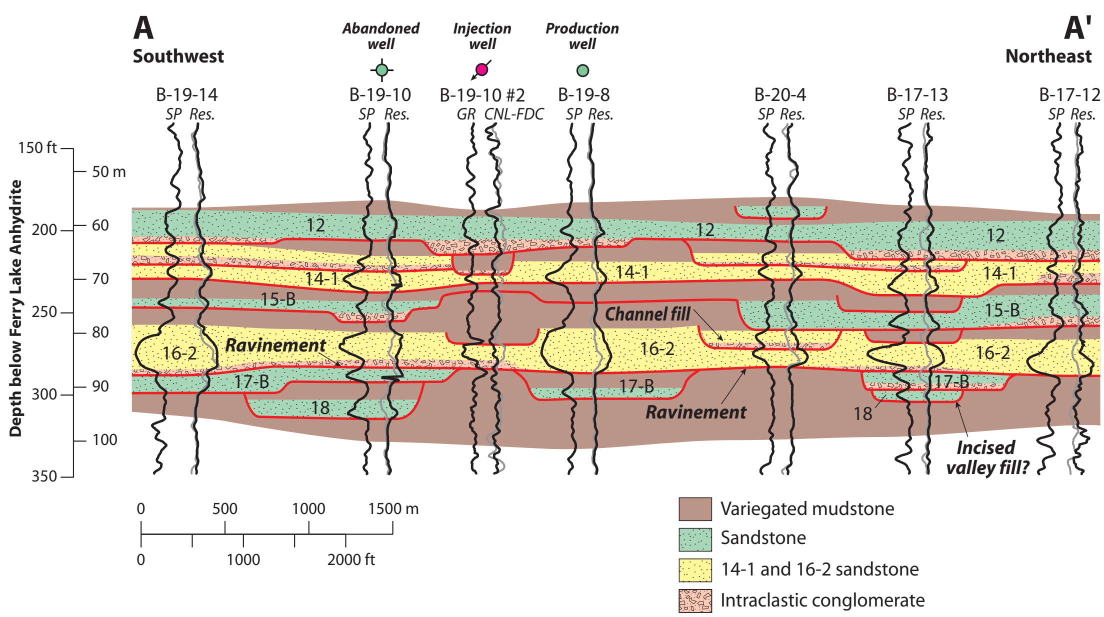


Figure 2. Stratigraphic cross section showing facies relationships in the upper Donovan Sand in the northeastern part of Citronelle Field, including CO_2 injection Well B-19-10 #2, to the left of center (J. C. Pashin, Geological Survey of Alabama).

A rolling ball viscometer was built for the present project and used to determine that the minimum miscibility pressure for Citronelle oil is between 2300 and 2600 psig. This determination shows that miscible conditions will be maintained at the depth of the target sands.

Measurements of soil gas composition versus depth, CO_2 flux from soil, soil temperature, and soil moisture have been made periodically to establish an environmental baseline, prior to CO_2 injection, at three locations surrounding the injector, three producers, and a plugged and abandoned well within the test pattern. The growth of trees and plants and their species distribution are being monitored in test plots near the injector, producers, and tank batteries. Since September 2007, monthly measurements of CO_2 in ambient air have been recorded at 100 points on a grid across Citronelle, to establish the CO_2 background level and its seasonal fluctuations.

Baseline measurements of ambient subsurface noise (passive seismic sources) were made using an array of wireless accelerometers placed along two lines, each spanning over 50,000 feet, to the southwest and to the south of the injection well. Shear-wave velocities were obtained to depths of 16,000 ft. Geostability analyses using a 1-D effective stress model and 3-D finite element model show only small deformation from overburden pressure on the oil-producing layer during CO_2 EOR.

Based upon reservoir simulations (Figure 3), it is expected that 7500 tons of CO_2 will be sufficient to demonstrate CO_2 EOR in the 14-1 and 16-2 Sands of the Upper Donovan and that an unequivocal effect of CO_2 on oil production will be observed within the time frame of the project. Injection of 7500 tons of CO_2 will be completed in 215 days. Significant incremental oil is first expected 275 days after the start of CO_2 injection, and a peak in oil production is expected between 400 and 500 days from the start of injection. Cumulative incremental oil at 500 days is projected to be 11,500 Stock Tank Barrels.

Water injection into the five-spot chosen for the first test, to establish the baseline for oil production, began in March 2008. Oil production from each

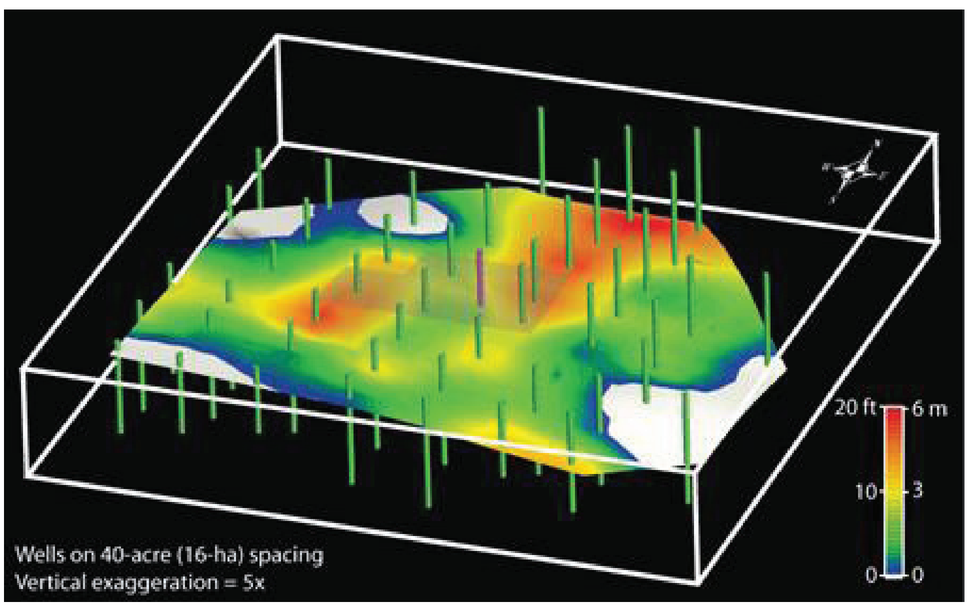


Figure 3. Three-dimensional model showing the net pay of the 16-2 target sand in the vicinity of the test well pattern. The test pattern is identified by slightly darker shading, with the injection well near the center of the figure shown in purple (D. J. Hills, Geological Survey of Alabama).

of the four producers ranges from 4 to 9 bbl/day. A CO_2-compatible triplex plunger pump was installed to deliver liquid CO_2 at high pressure from the storage tank to the injector (Figures 4 and 5). Flow meters, piping, and valves have been installed to measure produced fluid flow rates from the individual producers. The CO_2 injection rate is expected to be between 35 and 58 tons per day (600,000 to 1 million standard cubic feet per day). At these rates, injection of 7500 tons will take approximately 4 to 7 months, in the absence of upset conditions or down time.

Work during the coming quarter will focus on successful start-up of the first CO_2 injection, measurement of produced fluids, stratigraphy to support interpretation of the field data, additional reservoir simulation, seismic imaging, environmental monitoring, and laboratory determination of oil-CO_2-N_2 mixture properties.

For additional information related to this project contact Peter Walsh at the University of Alabama at Birmingham (pwalsh@uab.edu or 205-934-1826) or Chandra Nautiyal at NETL (Chandra.nautiyal@netl.doe.gov or 281-494-2488).

Figure 4. Jack C. Pashin (Geological Survey of Alabama) at the CO_2 injector, infill well B-19-10 #2. (Photo courtesy of Jack C. Pashin)

Figure 5. Triplex plunger pump with liquid CO_2 storage tank in the background, at B-19-8 Tank Battery, Citronelle Field. (Photo courtesy of Jack C. Pashin)

Study Reveals Potential for Oil Development in Utah and Surrounding States

by Thomas C. Chidsey, Jr., Utah Geological Survey

In 2005, NETL collaborated with the Utah Geological Survey (UGS) to conduct a study of remaining and undiscovered producible oil in Utah and the surrounding vicinity. The result is a new UGS bulletin, *Major Oil Plays in Utah and Vicinity,* that will help increase recoverable oil reserves from reservoirs in existing fields and from new discoveries by providing play portfolios for the three major oil-producing provinces (Central Utah thrust belt, Uinta Basin, and Paradox Basin) in Utah and adjacent areas in Wyoming, Colorado, and Arizona.

Utah oil fields have produced over 1.36 billion barrels (bbl), but statewide production reached its lowest level in 40 years in 2002, when oil production was 13.7 million bbl (Figure 1). However, in late 2005 oil production increased, due to the discovery of Covenant field in the central Utah thrust belt ("Hingeline") play, and to increased development drilling in the central Uinta Basin, reversing the decline that began in the mid-1980s. Over more than 40 years of widely variable production rates, Utah's proven oil reserves have remained above 200 million bbl, an indication that significant oil remains to be produced. As of 2007, proven reserves are relatively high, at 355 million bbl. With oil prices trending higher, secondary and tertiary recovery techniques should boost future production rates and ultimate recovery from known fields.

While Utah still contains large areas that are virtually unexplored, there is also significant potential for increasing recovery from existing fields through an improved understanding of reservoir characteristics and with state-of-the-art drilling, well completion, and secondary/tertiary production technologies. It is likely that operators can employ three-dimensional seismic surveys or soil-gas surveys to better define new exploration targets. Development of potential prospects is within the economic and technical capabilities of both major and small independent companies.

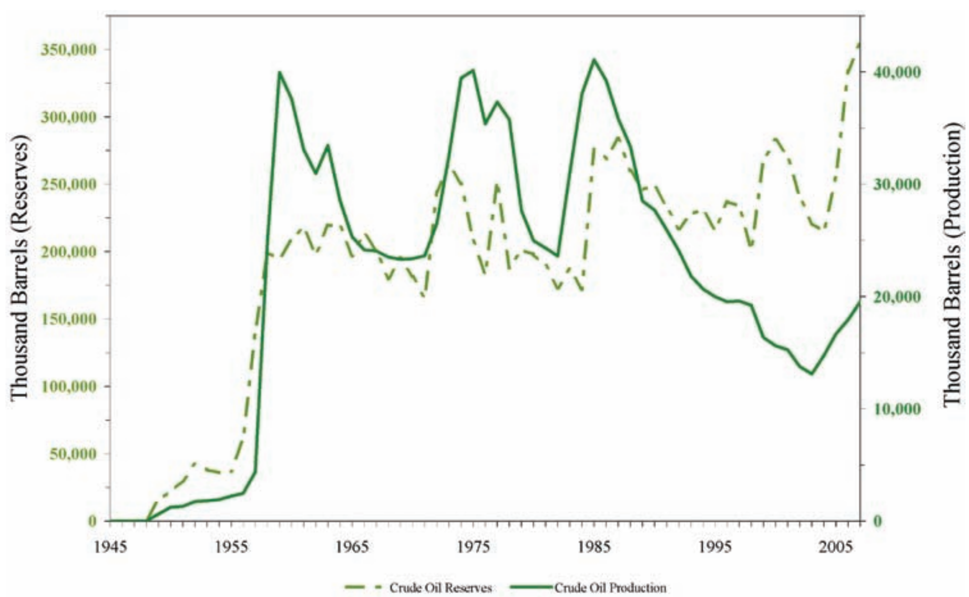


Figure 1. Oil production and reserves in Utah as of January 1, 2008 showing an increase due, in part, to the discovery of Covenant field in the new central Utah thrust belt play. Data source: UGS.

The U.S. Geological Survey defines a "play" as a set of known or postulated oil accumulations sharing similar geologic, geographic, and temporal properties such as hydrocarbon-generating source rocks, oil migration pathways, trapping mechanisms, and hydrocarbon types. This definition is the basis for the plays described in the study. The play portfolios include basic geologic information on each play such as tectonic setting, reservoir strata sequence, thickness, rock types (lithology), type of oil trap and source rocks, including timing, generation, and migration of oil. There is also a wealth of more specific information related to rock properties and oil and gas characteristics. Each play's exploration and production history is detailed, with a number of case-study oil field evaluations provided. Also included are summaries of the state-of-the-art current and potential best drilling, completion, and production practices, and the potential for new secondary/tertiary enhanced oil recovery. Finally, for each of the three plays there are descriptions of reservoir outcrop analogs, an assessment of exploration potential and trends, and maps of the plays and major oil sub-plays (Figure 2).

The Utah play portfolios in this study provide a comprehensive geologic, engineering, and geographic reference to help petroleum companies plan exploration, land-acquisition strategies, and field development. These portfolios can also help pipeline companies plan future facilities and pipelines. Other potential users of the portfolios include petroleum engineers, petroleum land specialists, landowners, bankers and investors, economists, utility companies, manufacturers, county planners, and numerous government resource management agencies.

The portfolio is available as a DVD from the NETL library and can be ordered via the NETL CD/DVD ordering system online at http://www.netl.doe.gov/publications/cdordering.html.

For additional information related to this project contact Thomas Chidsey, Jr. at UGS (tomchidsey@utah.gov or 801-537-3364) or Virginia Weyland at NETL (Virginia.Weyland@netl.doe.gov or 281-494-2517).

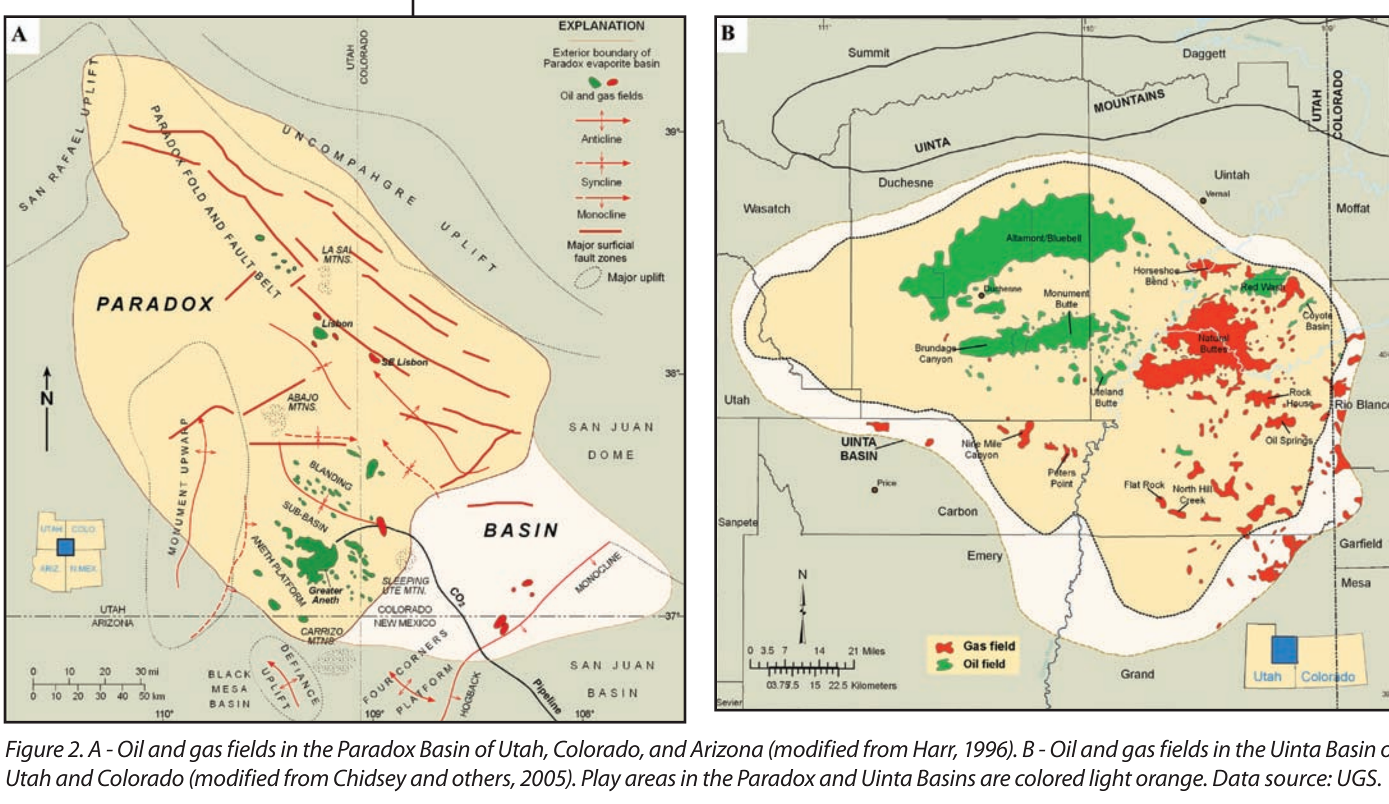
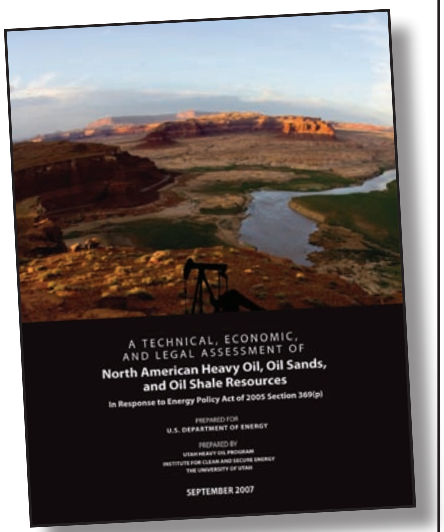


Figure 2. A - Oil and gas fields in the Paradox Basin of Utah, Colorado, and Arizona (modified from Harr, 1996). B - Oil and gas fields in the Uinta Basin of Utah and Colorado (modified from Chidsey and others, 2005). Play areas in the Paradox and Uinta Basins are colored light orange. Data source: UGS.

Institute for Clean and Secure Energy Provides Key Research for Unconventional Oil Development in the U.S.



"A Technical, Economic, and Legal Assessment of North American Heavy Oil, Oil Sands, and Oil Shale Resources" released September, 2007 by the Institute for Clean and Secure Energy, University of Utah.

In June of 2006, the University of Utah's Institute for Clean and Secure Energy launched a program to conduct research and seek solutions to the challenges that exist for managing and utilizing unconventional oil resources in the United States. The Program has succeeded in bringing into focus the resource potential of unconventional oil – including heavy oil, oil sands (also known as tar sands), and oil shale. It has also raised awareness of the obstacles that must be overcome in order to achieve widespread development of these resources.

EPAct 2005 Launched Effort

Section 369 of the Energy Policy Act of 2005 (EPAct 2005) created a preliminary framework for development of unconventional oil. Congress saw the need to examine domestic unconventional oil resources in order to reduce the nation's growing dependence on foreign oil and to encourage development of these resources in an economically and environmentally sustainable manner.

To better characterize the resource, Congress called on the Department of Energy to "update the 1987 technical and economic assessment of domestic heavy oil resources that was prepared by the Interstate Oil and Gas Compact Commission" and to develop "a publicly accessible online repository for information, data, and software pertaining to heavy oil resources in North America".

Updated Assessment Results

In September of 2007, the Institute for Clean and Secure Energy released its updated resource report: "A Technical, Economic, and Legal Assessment of North American Heavy Oil, Oil Sands, and Oil Shale Resources." The report includes not only updated resource estimates, but also a summary of current technologies used for extracting and processing unconventional oil. In addition, the report identifies regulatory, environmental, and socioeconomic concerns that are likely to influence decisions about how to develop these resources.

Unconventional Oil Types

Heavy oil, extra heavy oil, and the bitumen in oil sands all represent organic matter that was buried 2-4 kilometers below ground, in a zone known as the "oil window," converted to crude oil by the earth's internal heat, and subsequently biodegraded by bacteria. The bacteria consumed lighter oil molecules, leaving heavier, more viscous oil molecules in the rock. Because of their high viscosity, production of heavy oil, extra heavy oil, and bitumen requires either heating or dilution.

Oil shale, on the other hand, is a fine-grained sedimentary rock rich in kerogen, the precursor to oil. In general, oil shale has not been deeply buried, so it has not been subjected to temperatures sufficiently high to form oil. Oil shale production requires heating the rock in order to convert the kerogen into oil, and then extracting the oil.

Unconventional Oil Resource

According to the Institute's updated resource report, the largest heavy oil/extra heavy oil deposits in North America are found in western Canada

(101.7 billion barrels Original Oil In Place or OOIP), California (75.8 billion barrels OOIP), and northern Alaska (25-30 billion barrels OOIP), with smaller fields distributed throughout the U.S. and Mexico. In the U.S., heavy oil is the only unconventional oil that is being produced on a commercial scale.

North American oil sand deposits are found in Canada and the U.S., with about 1.7 trillion barrels OOIP in oil sands in western Canada and 54 billion barrels OOIP in oil sands in the U.S. The largest deposits in the U.S. are found in Utah, but these are only produced on a pilot scale at the present time. In Canada, oil sands are produced commercially—using either surface mining/hot water extraction or *in-situ* processing via steam-assisted gravity drainage to liberate the bitumen from the sand and clay particles.

The Institute's report also summarizes the principal oil shale formations found in Canada and the U.S. The Green River Formation, which occurs in Colorado, Utah, and Wyoming, contains the largest oil shale resource in the U.S., with an estimated 1.5 to 1.8 trillion barrels OOIP in its most kerogen-rich horizons. Oil shales in the eastern U.S. have a lower total organic content but are estimated to contain 189 billion barrels OOIP in the form of kerogen. Currently, oil shale is not produced commercially anywhere in North America.

Online Repository and Interactive Map

In addition to publishing the updated resource report, the Institute for Clean and Secure Energy created an interactive, online repository of information related to unconventional oil resources. The online repository includes a searchable library with documents dating from 1901-2009. The user-friendly ArcIMS interactive map serves as a geospatial portal to the repository and provides users with unconventional oil field and well data displayed in a geospatial setting.

Multidisciplinary Unconventional Fuels Research

Five Institute research projects were sponsored. One project developed a water management model for the Uinta Basin, Utah, where significant oil sands and oil shale deposits occur. Three projects focused on simulations of *in situ* production of both oil sands and oil shale resources and the requisite inputs for those simulations, including characterization of the depositional heterogeneity in the eastern Uinta Basin and data on Green River kerogen pyrolysis. The final project was an economic and legal analysis of commercial oil shale leasing under the mandates of EPAct 2005. These research projects have laid the foundation for the multidisciplinary research approach being pursued by the Institute today.

The technical research program, organized around the theme of validation and uncertainty quantification through tightly coupled simulation and experimental designs, is integrated with the legal, environment, economics and policy research program to achieve the dual goals of clean and secure energy from domestic oil sands and oil shale resources.

The research targets include:

Oil shale/sands utilization with efficient CO_2 capture – This research brings together multi-scale experimental measurements and computer simulations with a focus on flameless operation for different process heater design options burning a wide range of gaseous fuels such as natural gas, refinery gas and the by-product gas stream from in-situ oil shale/sands production.

In-situ thermal processing – The objective of this research is to create models and simulation tools that apply to all in-situ thermal processes by gathering experimental laboratory data for model validation on multiple scales, by developing the simulation tools necessary to capture the relevant physical processes, and by performing validation and uncertainty quantification for specific laboratory and pilot-scale systems.

Environmental, legal, economic & policy framework – This research shall address legal, policy and economic gaps that pertain to in-situ liquid production from oil shale/sands. It shall identify issues of land use planning, fragmented resource ownership, co-located resources, water use and reclamation.

Assessment – An assessment that examines limiting factors to the development of domestic heavy oil, oil sands, and oil shale resources and identifies policy, technology, and economic gaps that could be advanced through increased research activities shall be researched and published.

Summary

The size of the unconventional oil resource in North America is significant. In fact, it far exceeds most estimates of the total remaining conventional oil reserves for the entire world. Although heavy oil is being produced commercially in the U.S., Canada, and Mexico, oil sands and oil shale production are lagging behind because of technical, economic, and environmental obstacles that still need to be resolved. These issues include the high cost of unconventional oil processing, land and resource management, climate change, and air and water quality laws. The Institute's updated report on unconventional oil resources, online repository/interactive map, and multidisciplinary research have helped to raise awareness of these challenges and have provided solutions to the problems of unconventional oil development in the U.S.

For more information on the Institute for Clean and Secure Energy, please contact: Philip Smith, Institute Director, at Philip.Smith@utah.edu or 801 585-3129; or Robert Vagnetti, National Energy Technology Laboratory Project Manager, at Robert.vagnetti@netl.doe.gov or 304 285-1334.

LINKS

The Institute for Clean and Secure Energy resource report, "A Technical, Economic, and Legal Assessment of North American Heavy Oil, Oil Sands, and Oil Shale Resources," can be accessed and downloaded at: http://www.heavyoil.utah.edu/

The Insitute's online repository is accessible at: http://ds.heavyoil.utah.edu/dspace/ for the online, searchable literature library; and http://map.heavyoil.utah.edu/website/uhop_ims, for the interactive maps database.

Better Reservoir Understanding Needed to Drive Bakken Shale Development

The Bakken Formation is a significant emerging play in the Williston Basin of Montana and North Dakota that, according to a recent United States Geologic Survey estimate, contains between 3 and 4.3 billion bbl of undiscovered, recoverable oil. Expansion of the play is currently underway and has resulted in new discoveries, however no predictive hydrocarbon system or reservoir geo-model exists for this play. NETL is participating in a jointly funded study to develop a predictive model for future exploration.

Bakken Characteristics

The Bakken Petroleum System includes all the elements necessary for such a large resource, including reservoir rocks, abundant organic-rich source beds, and effective, widespread seals. Sedimentation occurred throughout the Phanerozoic, and the thickness of the stratigraphic section is approximately 16,000 feet. While the various productive lithologies of the Devonian-Mississippian Bakken Formation are all low porosity and low permeability, a system of fractures provides for economic production rates, largely from horizontal wellbores completed with multiple fracture stimulations.

While the Bakken has been the focus of several cycles of exploration activity since the 1950s, the recent development of the Elm Coulee area of eastern Montana is the most significant of these cycles to date. Expansion of the play into western North Dakota, currently underway, has resulted in new discoveries such as the Parshall Field. The new productive areas in North Dakota suggest the existence of an extremely large resource play; however, new methods are required to most efficiently develop it.

Elm Coulee Field

Although a relatively new field, Elm Coulee has already produced in excess of 41 million barrels of oil and 24 BCF gas from over 400 horizontal wells (Figure 1). The field is being developed using horizontal drilling to tap the middle member of the Bakken. The Elm Coulee wells are generally fracture stimulated with gelled water and sand (~5,000 bbl gelled water

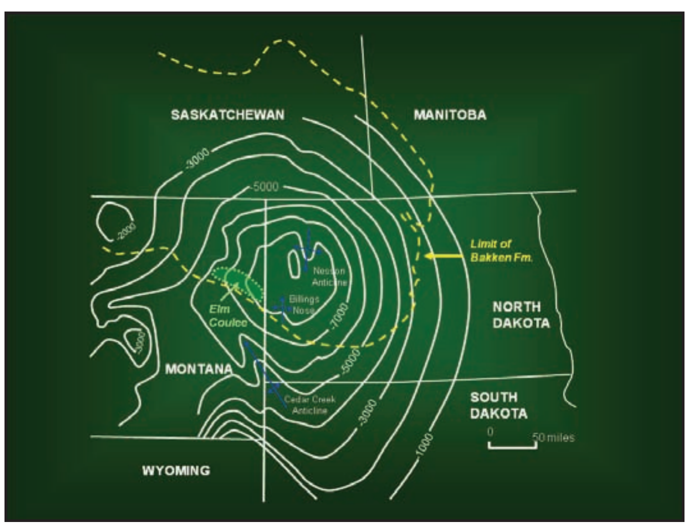


Figure 1. This map of the Williston Basin shows the extent of the Bakken Formation within the basin. The outline of the Elm Coulee field and major structural features are also illustrated. (Courtesy Colorado School of Mines)

and 400,000 pounds of sand per lateral). The area was targeted for vertical drilling in the late 1990s and horizontal drilling began in 2001. The middle Bakken in this area is interpreted as a dolomitized carbonate bar complex.

The reservoir extends over 450 square miles and has a relatively low porosity of 8 to 10 percent. Permeability averages 0.05 millidarcy (md). Natural fracturing is thought to contribute to production. Initial production from wells ranges from 200 to 1,900 BOPD. The field is being developed on 640 and 1280 acre spacing units. The Elm Coulee area has many of the characteristics of a resource play: continuous accumulation, large areal extent, predictability, and repeatability. As well, resource development is technology driven. Estimated recovery per well is 350 to 600 MBO and estimated ultimate recovery for the field is expected to be greater than 200 MMBO.

Joint Study to Develop Model Underway

NETL is participating in a jointly funded study to develop an initial "alpha" version of a predictive exploration model that can be used for future identification of high potential fairways and traps within the Bakken hydrocarbon system. Partners include the Colorado Energy Research Institute (at the Colorado School of Mines), Fidelity Exploration Company, Idaho National Laboratory, The Discovery Group, and Samson Resources Company. The researchers are basing the model on the integration of a sub-regional stratigraphic and reservoir characterization, rock-physics-calibrated seismic attribute analyses, and acoustic impedance data developed for different levels of organic richness and maturity. It will also include an estimate of secondary permeability potential derived from fracture analysis. The predicted attributes will be compared to known seismic, log and core data throughout the Williston Basin, to validate the model.

Significant Progress Reported

The project has made significant progress in its early stages. A sequence stratigraphic framework has been constructed from detailed descriptions of 27 cores stored at the United States Geological Survey in Denver and at the core repository at Colorado School of Mines (CSM). Researchers have prepared a preliminary regional stratigraphic framework from a newly

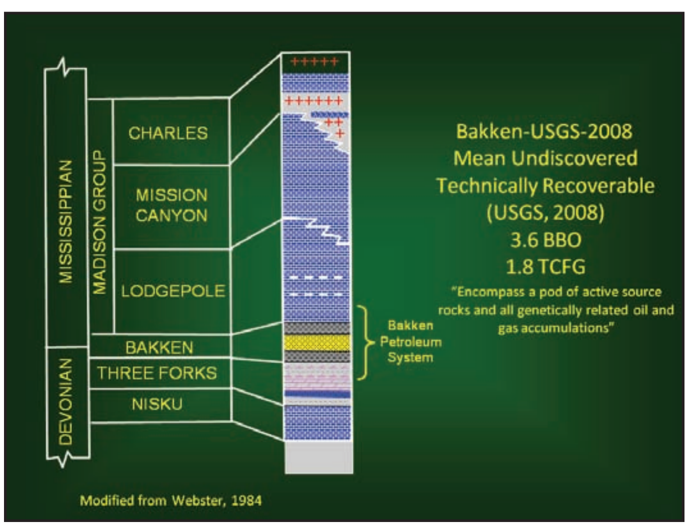


Figure 2. The Bakken Petroleum system includes the Bakken formation and parts of the Lodgepole and Three Forks formations. (Courtesy Colorado School of Mines)

acquired geophysical well log database, donated by MJ Systems. A major sequence boundary has been identified within the Middle Bakken, and stratigraphic pinchouts of the Lower Bakken shale, and the Middle Bakken have been mapped.

Initial observations describe the reservoir character of the siliceous dolomite and dolomitic sandstones comprising the Middle Bakken reservoirs. Two field studies are continuing in the Parshall and Elm Coulee fields. In addition, a study has begun of the lower Lodgepole formation and the upper portion of the Three Forks formation, both of which are elements of the Bakken petroleum system, and potential reservoirs (Figure 2). The Three Forks formation lies directly under the Bakken formation. Its potential is large, as indicated by a recent well test by Continental Resources that saw the Bice 1-29H, sec 29, T147, R96, Dunn Co. well flow an average of about 700 bbl/day over a seven day period.

In addition, a test set of three reservoir rock samples has been analyzed using the high resolution SEM tool, QEMSCAN®, in order to quantify mineralogical composition and porosity, and to image pore system geometry. The results are enlightening, and additional samples have been submitted for analysis. These data will be integrated with the core descriptions as development of the model continues.

An initial test set of core gamma ray scans were conducted on three cores stored at CSM, and scans of the base set of cores is progressing. The scans are total count scans, and can be directly compared to gamma ray logs collected in wells. The measurements were taken every foot on the bulk core samples and normalized by sample mass. The relative values are valid among the cores, and a calibration factor is being developed to translate them directly into API gamma ray units. Such core gamma ray scans will be used to tie core depths to well log depths. This process is complicated in the Bakken, because the shales are so radioactive that the tool response can be off-scale.

Given the importance of fractures to reservoir performance, the research team compiled a bibliography of publications on the tectonic history of the Williston basin and documented the current state of knowledge of fracture systems in the Bakken. Follow-up field work has commenced in the Big Snowy and Little Rocky Mountains, Montana, and the Beartooth Range in Wyoming and Montana. Fracture orientations, fracture density, and fracture lengths are being mapped in these areas. The researchers will relate these data to fracture patterns identified using seismic and core data.

Additional work is ongoing to: 1) investigate variations in velocity, impedance and composition with maturity in the Upper and Lower Bakken shale, and 2) identify samples with variations in total organic content (TOC) at different depths within a well. If there appears to be a large spread in TOC values, the core will be sampled and analyzed for TOC and impedance correlations.

This project will improve understanding of the Bakken Petroleum System and allow operators to increase both production and recovery factors.

For additional information related to this project contact Frederick Sarg at Colorado Energy Research Institute, Colorado School of Mines (jsarg@mines.edu or 303-273-3729) or Jesse Garcia at NETL (jesse.garcia@netl.doe.gov or 918-699-2036).

Seismic Stimulation Could Revive Failing Oil Fields

The notion that seismic waves might cause increased oil production from wells in nearly depleted reservoirs has been considered before, but a theoretical underpinning of the physical process has not been defined. A comprehensive statement of the scientific basis for this relatively un-tested technique, along with well-documented field tests, could provide the foundation for a potentially powerful production enhancement tool for small producers operating marginal fields.

The Research Partnership to Secure Energy for America (RPSEA), has selected Lawrence Berkeley National Laboratory (LBNL) and Berkeley GeoImaging Resources, LLC (BGI) to define the process and quantify the potential benefits of using seismic stimulation to enhance oil production in declining oil reservoirs. The goal of this project is to perform field experiments of seismic stimulation in collaboration with a small producer (BGI), and to test the physical basis for how seismic stimulation works.

Compared to other methods of enhanced oil recovery, seismic stimulation offers some potential advantages: (1) seismic waves propagate everywhere through a reservoir and can stimulate trapped oil in places where delivery of injected fluids is not possible; (2) it is inexpensive; and (3) it raises no environmental concerns. For a limited investment, a small producer has the potential for a big return. However, the technology is still relatively untested and poorly understood.

Limited Testing Has Been Encouraging

The most definitive field tests to date of seismic stimulation have been conducted by Occidental Petroleum Corp. (Oxy) in a sandstone reservoir at Elk Hills, CA. Oxy has been using the Hydro-Impact seismic source offered by Applied Seismic Research (ASR), which represents the state of the art in large amplitude downhole sources. The tool compresses produced water in a compression chamber at the bottom of a well by raising a plunger using a sucker rod string driven by a pump jack at the surface. When the ten-foot long plunger reaches the end of its stroke, the compressed water is suddenly released downward, creating a seismic wave in close proximity to the reservoir being stimulated. Each plunger cycle takes 7 to 10 seconds. The ASR source is designed to run continuously for up to 6 months. A similar tool is offered commercially by Oil Enhancement Tool, LLC.

Production results from the 68 producing wells in Oxy's Elk Hills sandstone reservoir in California, show a 50 percent increase in oil production relative to the historical decline rate after stimulation was applied (Figure 1). Over the 540 day period that stimulation was applied in this experiment, roughly 160,000 barrels of incremental oil were recovered based on a historic production projection. These and other Oxy results from the Permian Basin in Texas have recently led the Texas Railroad Commission to certify seismic stimulation as an official Enhanced Oil Recovery (EOR) process, a designation that carries tax benefits in the state of Texas.

Physical Basis for Seismic Stimulation

There is reason to believe that seismic stimulation can work to enhance oil production in declining fields under the proper circumstances. In order for an oil "ganglion," or string of interconnected oil droplets within the pore space of a rock, to be immobile in the presence of an applied fluid pressure gradient (production gradient), it is necessary that the pressure drop along the length of the ganglion due to the production gradient be balanced by a capillary pressure increase. In this case, as the production gradient tries to push the leading downstream oil meniscus through a constriction in the pore space, the radius of curvature of that leading meniscus is reduced relative to the farthest upstream meniscus. The difference in radius of curvature creates a capillary pressure difference that opposes the production gradient.

A seismic wave adds to the production gradient and can push the stuck bubble through its downstream bounding pore-throat constriction if the wave amplitude is large enough. Researchers with LBNL have derived a dimensionless criterion for how large the seismic-wave amplitude must be relative to the background production gradient in order for a stuck oil ganglion to be liberated. If the seismic wave is able to push the downstream meniscus through its bounding constriction, the bubble begins to flow again under the production gradient until it becomes stuck on another tight constriction. For this reason, the seismic stimulation must be repeated.

Coalescence of oil bubbles (or oil ganglia) to form longer strings is another key element of the process physics. Longer ganglia are more mobile than shorter bubbles because the production pressure drop that is driving them increases with length, while the opposing capillary-pressure barriers (the pore space constrictions) are independent of length (Figures 2 and 3). The creation of longer bubbles, as bubbles are "unstuck" by the seismic waves, could also act to increase oil production. The project will produce a coherent, scientifically defendable physical explanation for the various phenomena that occur during the process.

Field Experiment to Provide Test Data

LBNL is working with a small producer (BGI) at a mature field they own and operate to demonstrate whether, and by how much, seismic stimulation is able to increase production from the test wells. The BGI field is typical of those owned by small producers, and is produced by conventional beam pumps. Seismic stimulation is targeting trapped residual oil that would not otherwise be produced. It is anticipated that the process will increase the production rate in these fields by at least several tens of percent, and possibly much more.

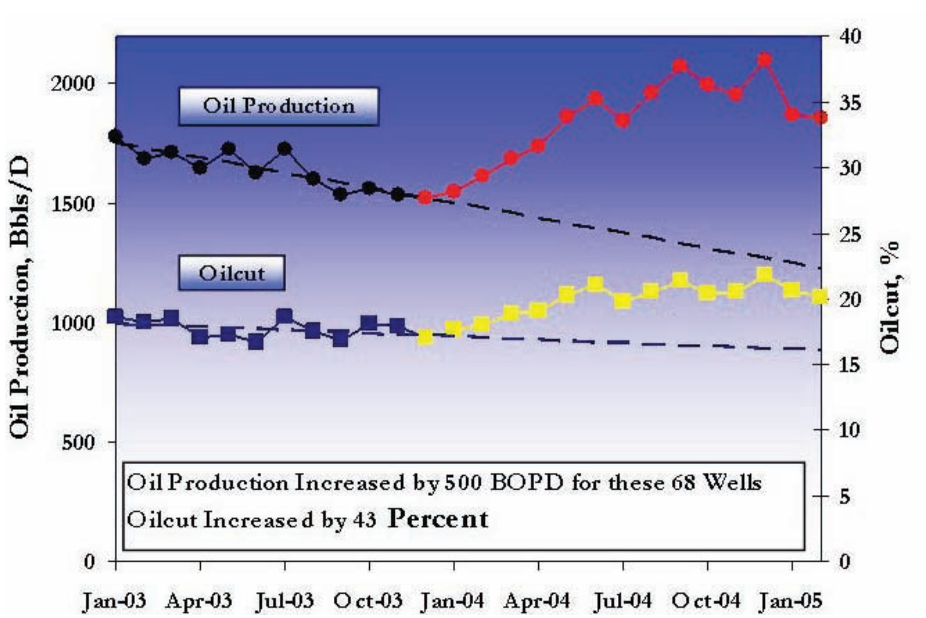


Figure 1. Plot illustrating production from the 68 producers in Oxy's Elk Hills, CA field. Seismic stimulation began September 2003 and production increase (the colored points) began 2 months later. Over this time period, production parameters were not significantly altered. Graph courtesy of Applied Seismic Research.

Further, by comparing individual well production to numerical model projections (maps) of where the stimulation process is expected to be beneficial, this project aims to validate and quantify the underlying physical basis for seismic stimulation. Refining LBNL's ability to make such maps will benefit not only BGI, but all small producers considering seismic stimulation. Such maps could be used prior to stimulation to determine whether this EOR technique is appropriate for a given reservoir, and where to place the seismic source.

BGI has recently acquired both 3D seismic data and well log data at the proposed test reservoir in Oklahoma and has begun the construction of a detailed reservoir model. BGI will make this data available to LBNL for testing the physical basis of seismic stimulation. This past year, BGI has drilled several new wells and the field now contains producing wells that exhibit a range of oil production rates. BGI will share in the cost of drilling a final new well that will be used to house the seismic source.

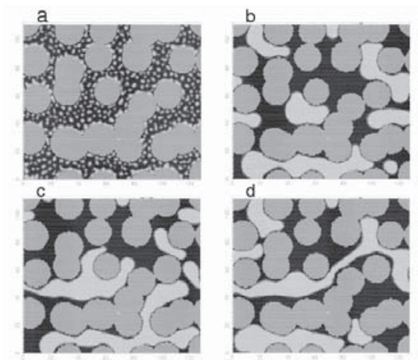


Figure 2. Snapshots during the four stages of the seismic stimulation simulation, with fluid flow from left to right. Solid discs are gray, oil is light gray and the water is black. (Lawrence Berkeley National Laboratory)

Testing Scheduled for 2010

The seismic stimulation will begin at the Oklahoma test reservoir in May 2010 and will run continuously for 8 months or until the source requires replacement. During this time period, production in all wells will be continuously monitored.

Typically, between 40 and 70 percent of the oil in place in a mature reservoir can be considered unrecoverable oil. Some of this remaining oil is trapped in such tight portions of the pore space that it will never be produced. It is uncertain what fraction of the remaining oil in a reservoir can be recovered using seismic stimulation. Enhancements in the rate of production are anticipated to range from 10 to 60 percent, based on results from prior field trials, as well as LBNL numerical modeling of the pore-scale physics. The research team anticipates that the producing wells closer to the source will experience better incremental recovery than those farther away.

For further information related to this project contact Steven Pride at Lawrence Berkeley National Laboratory (spride@lbl.gov or 510-495-2823) or Martha Cather at Research Partnership to Secure Energy for America (mcather@rpsea.org or 281-313-9555).

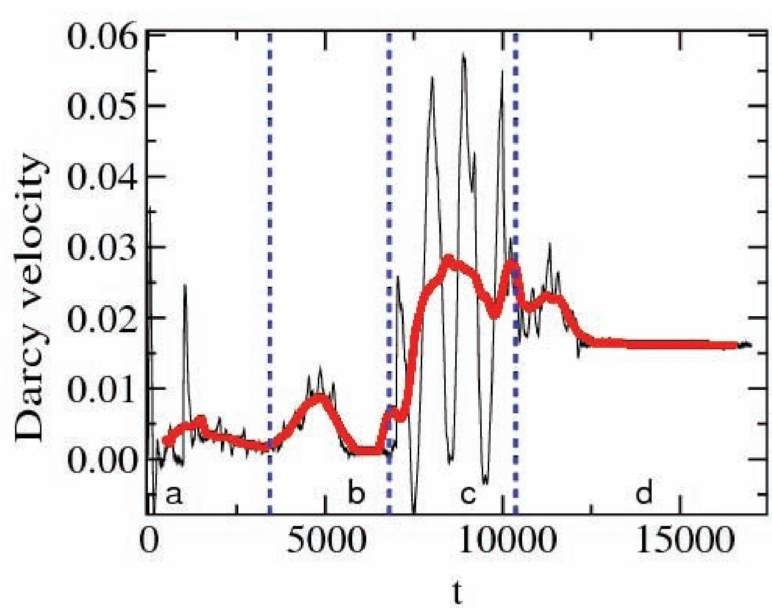


Figure 3. The spatially averaged Darcy velocity in the system as a function of simulation time (in units of the time step) corresponding to the geometry and flow in Fig. 2. The thin curve is the instantaneous velocity, while the thick curve is a running average over a time window of Δt = 1,000. In all graphs, units are lattice-Boltzmann units. (Lawrence Berkeley National Laboratory)

Reconsideration of Screening Criteria for Polymer Flooding

Alaska's North Slope contains over 20 billion barrels of heavy/viscous oil. The formations that hold vast viscous oil reserves are Ugnu, West Sak, and Schrader Bluff. Thermal, miscible gas, and water-alternating-gas EOR methods have been evaluated and deemed not suitable for these formations. NETL is jointly funding a project with the New Mexico Institute of Mining & Technology to develop methods using water-soluble polymers to recover viscous oil from unconventional reservoirs such as those on Alaska's North Slope.

The project has three technical tasks. First, limits will be re-examined and redefined for where polymer flooding technology can be applied. Second, the project will test existing and new polymers for effective polymer flooding of viscous oil, and will test newly proposed mechanisms for oil displacement by polymer solutions. Third, it will develop novel methods of using polymer gels to improve sweep efficiency during recovery of unconventional viscous oil.

It is important to determine the rheology in porous media for existing EOR polymers for the range of permeabilities anticipated in North Slope viscous oil reservoirs that might be candidates for polymer flooding. In general, the project is trying to determine the most cost-effective polymer (most viscosity for the least cost) that will efficiently enter and flow through North Slope rock. The performance has been characterized in 55-millidarcy (md), 269-md, and 5,120-md cores for nine commercially available EOR polymers, including one xanthan, one diutan, and seven partially hydrolyzed polyacrylamides (HPAM), with molecular weights ranging from 6 to 22 million daltons. None of the polymers exhibited severe face-plugging in any of the cores.

The project has further examined polymer solution rheology in porous media over a wide range of flux values: from 0.01 to 1,000 ft/d for xanthan and diutan solutions and from 0.01 to 240 ft/d for HPAM solutions. Consistent with previous literature, it was confirmed that xanthan solutions show shear-thinning or pseudoplastic behavior in porous media (Figure 1). Also consistent with previous literature, it was confirmed that HPAM resistance factors increase with increased flux at moderate to high flux values (Figure 2). This behavior was attributed to the viscoelastic character of HPAM and the elongational flow field in porous rock. In these cores, xanthan and HPAM solution rheology in porous media correlated very well using the parameter: $u(1-\varphi)/(\varphi k)^{0.5}$, where u is flux, φ is porosity, and k is permeability. The onset of pseudodilatant (viscoelastic) resistance factors correlated closely with the transition from Newtonian to shear-thinning viscosity behavior. These correlations will be very helpful in future work in quantifying the potential for polymer flooding.

At low flux values in a 14.4-cm-long, 55-md Berea sandstone core, both xanthan and HPAM can exhibit resistance factors that are much higher than expected and an apparent shear-thinning behavior that deviates from expectations from viscosity-versus-shear-rate data. Using xanthan injection into a 122-cm-long, 57-md Berea core (Figure 3), the project demonstrated that this behavior was an experimental artifact (probably associated with microgels or other very high molecular weight polymer species) that is not expected to materialize in field applications. Future tests will examine this issue for HPAM solutions.

Figure 1. Correlated resistance factors for 600-ppm CP Kelco K9D236 xanthan. (New Mexico Institute of Mining and Technology)

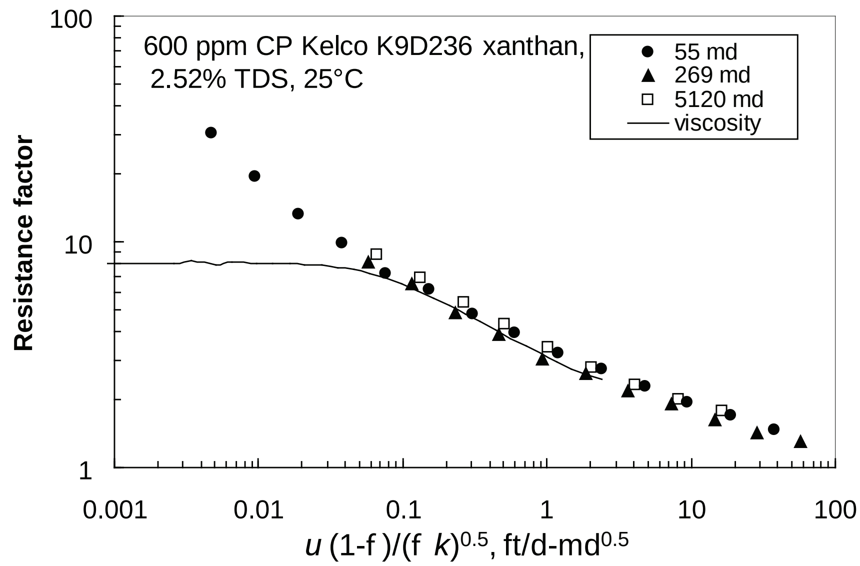


Figure 2. Correlated resistance factors for 2500-ppm SNF 3230S HPAM. (New Mexico Institute of Mining and Technology)

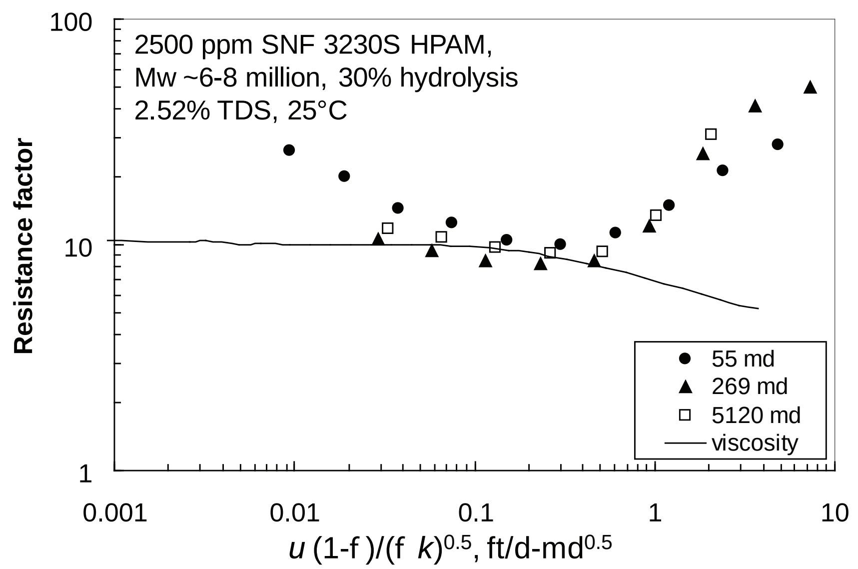
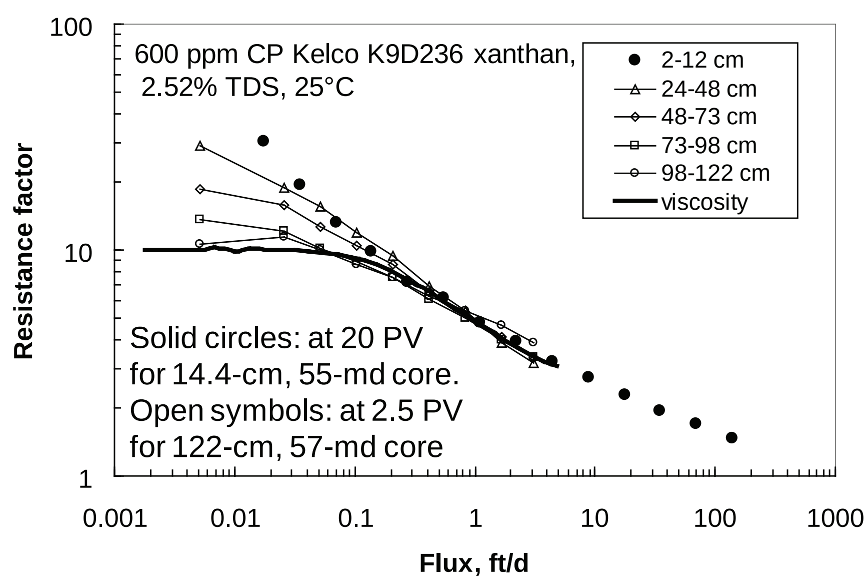


Figure 3. Project results demonstrate that higher than expected resistance factors are an experimental artifact. (New Mexico Institute of Mining and Technology)



A key issue for polymer flooding in a viscous oil reservoir is whether fluid injectivity will be sufficiently high to allow the oil to be displaced and produced at an economic rate. The research team investigated this question with the help of ConocoPhillips, which provided oil and data for a North Slope viscous oil reservoir.

In this reservoir, results from simulations showed that horizontal wells provide injectivities and productivities that are 9-10 times those expected for unfractured vertical wells. Particulate matter in injected water or polymer solutions was 65 times more likely to plug a vertical well than a horizontal well (assuming that fractures do not open during the course of injection). Using previously developed methods and the project's experimental polymer rheology in porous media (described above), an estimate was made of the injectivities associated with the project's polymer solutions under North Slope conditions.

The pseudodilatant (viscoelastic) behavior of HPAM polymers could lead to significantly reduced injectivity in unfractured vertical North Slope injection wells (2-8% that of water for the HPAM solutions investigated in this study). In contrast, in North Slope unfractured horizontal wells, injectivity reductions should be significantly less severe (with polymer injectivity 10-15% that of water for our cases). The pseudoplastic (shear-thinning) xanthan and diutan solutions have an injectivity advantage over HPAM solutions in unfractured vertical wells, with estimated injectivity values around one-third that of water for the solutions that were examined.

For horizontal wells, this advantage is diminished considerably. For a horizontal well with a vertical fracture that perfectly follows the well and extends to the full formation height (i.e., true linear flow), water injectivity was estimated to be about 19 percent greater than for an unfractured horizontal injection well. Flux values could typically be 0.01 ft/d or less deep within the target North Slope viscous oil reservoirs. These velocities are sufficiently low that they merit further study and clarification of polymer solution rheology in porous media at these low rates. Future work will also examine the utility of multiple fractures that may cross a horizontal well (i.e., quantifying improvements in injectivity and sweep efficiency versus possible detriments from accentuated channeling).

For additional information related to this project contact Randy Seright at the New Mexico Institute of Mining and Technology (randy@prrc.nmt.edu or 575-835-5571) or Ginny Weyland at NETL (virginia.weyland@netl.doe.gov or 281 494 2517).

NETL and CNPC Launch Technology Exchange

Scientists, engineers, and managers representing NETL and the Chinese National Petroleum Corporation (CNPC)—China's largest oil company—met for an initial face-to-face technology dialogue under a Memorandum of Understanding (MOU) signed by the organizations in Beijing last October to pursue collaborative R&D in the area of fossil energy. A delegation of fifteen Chinese technologists visited NETL in Pittsburgh on August 31st - September 1st for the first of what is envisioned as a series of meetings (see photo). The delegation was led by Dr. Jai Chengzao of CNPC.

Meeting outcomes included identification of technology exchange leaders, and the development of plans for collaborating in four topical areas: methane hydrates, shale gas, high pressure/high temperature drilling, and enhanced oil recovery using carbon dioxide. The two organizations are contemplating a reciprocal visit by NETL researchers to CNPC in March/ April 2010.

The MOU is one of three signed in the last year by NETL with Chinese scientific and technical organizations to foster collaboration among Chinese and American scientists and engineers in studies relating to the efficient use of fossil fuels, and the capture and storage of carbon dioxide. Such collaboration by the two largest users of fossil fuels and generators of carbon dioxide is key for developing global solutions to climate change and energy security concerns.

The NETL-CNPC agreement was historic for two reasons: it represented NETL's first agreement with a company from the Peoples Republic of China and it marked CNPC's first agreement with an agency of the United States Government. The agreement extends for five years, during which cooperative research and development on primary and enabling technologies as well as assessments of technology options and economics will be conducted.

Chinese delegation with NETL scientists, engineers and managers, outside NETL offices in Pittsburgh, PA. NETL Director Carl Bauer and Dr. Jai Chengzao of CNPC (front row center) led the technology exchange.

Fayetteville Shale Infrastructure Placement Analysis System Debuts

A new software program developed by a recent, joint project between NETL, the University of Arkansas, Fayetteville, and Argonne National Laboratory will make it much easier for operators in the Fayetteville Shale gas play to evaluate placement and install surface infrastructure. The Fayetteville Shale natural gas Infrastructure Placement Analysis System (IPAS) is a secure, web-based toolkit that can help streamline several critical tasks involved with the placement and permitting of new drilling pads, gathering lines, and other infrastructure. The system has a number of unique features:

- Initial environmental screening of proposed locations is available to producers through a variety of models, including slope analysis, spill modeling, and proximity to sensitive areas.
- Secure version control allows producers to compare model results for multiple possible locations.
- Proposed locations can be reviewed by multiple users within the same company.
- Finalized proposed locations can be submitted electronically to regulatory agencies.
- Regulators view the submittals in the same toolkit, allowing them to review the environmental screening model results.
- Regulators can approve locations as submitted or propose changes, which are added to the producer's database for examination.
- Producers or regulators can add their own data to view on the system; added data is not accessible by others.
- Producers can download their own features for use with desktop GIS applications.

Every GIS data layer has a limit to its "spatial accuracy", typically related to the manner in which the data was collected or created. In the Fayetteville Shale IPAS toolkit, the boundary of each critical data layer has been converted into a fuzzy "uncertainty zone", the width of which typically reflects a 95% confidence level of boundary accuracy. Furthermore, the boundary of infrastructure features placed using IPAS also reflect spatial uncertainty. Whenever the Sensitive Area Analysis is performed, the results reflect whether there is overlap between the "certain" feature and "certain" sensitive area, or perhaps only between the uncertainty zones.

Protection of water resources is a key concern for everyone involved with development of the Fayetteville Shale play. Around fifty percent of the total area falls either directly within subwatersheds containing state-designated Extraordinary Resource Waters or within subwatersheds that are upstream of Extraordinary Resource Waters. To understand the possible impact of a spill from a drilling site, such as could be caused by the failure of a retaining wall of a reserve pit, the Fayetteville Shale IPAS provides a spill modeling tool. Run on top of a filled-depression digital elevation model, the spill model will show the spill flow path down to the nearest water body or bodies.

Recognizing the need for protection of private data in this competitive market, the Fayetteville Shale IPAS is designed with security and reliability as key concerns. IPAS runs on a dedicated, limited access server located in a climate-controlled server room with full UPS and generator backup and computer-room rated fire suppression system. All web pages utilize Secure Socket Layer (SSL) protocol.

Features entered by different producers are stored in totally independent tables, eliminating possibility of access by other producers. All passwords are fully encrypted ("hashed and salted") on the server, and all industry best practices for secure web applications are followed.

For further Information, contact Jesse Garcia at NETL (jesse.garcia@netl.doe.gov or 304-285-0256), Greg Thoma at University of Arkansas, Fayetteville (gthoma@uark.edu or 479-575-4951), or John Veil at Argonne National Laboratory (jveil@anl.gov or 202-288-2450).

NETL Projects to Improve Environmental Performance for Flowback and Produced Water

The Office of Fossil Energy's National Energy Technology Laboratory (NETL) has selected nine new projects targeting environmental tools and technology for shale gas and coalbed methane (CBM) production. NETL's goals for these projects are to improve management of water resources, water usage, and water disposal, and to support science that will aid the regulatory and permitting processes required for shale gas development.

A primary goal of Fossil Energy's Oil and Natural Gas Program is to enhance the responsible development of domestic natural gas and oil resources that supply the country's energy. A specific objective is to accelerate the development and demonstration of technologies that will aid our country's independent producers in dealing with use and treatment of water related to natural gas and oil production.

The following recipients will help provide the new technologies, tools, strategies, and knowledge toward reliable and environmentally responsible development of natural gas.

- ALL Consulting, Tulsa, Okla.—The objective of this project is to develop a modeling system that will allow operators and regulators to plan all aspects of water management associated with shale gas development, including water supply, transport, storage, use, recycling, and disposal. This system will be used in planning, managing, forecasting, permit tracking, and compliance monitoring.
- General Electrical Company, Niskayuna, N.Y.—This project will develop a low-cost, mobile process to treat the total dissolved solids in the flowback water from hydraulic fracturing operations. The researchers will develop both a flowback water pretreatment

process and a membrane-based partial demineralization process that yields an effluent suitable for reuse as hydraulic fracturing water (frac water).

- West Virginia University, Morgantown, W.Va.—The primary objective of this project is to develop and demonstrate a process for the frac water returns from Marcellus Shale wells. The process will include a pretreatment filter coupled with a combination of one or more treatment elements.
- University of Arkansas, Fayetteville, Ark.—This project aims to develop a water management decision-support system by modifying and integrating a state-of-the-art water resource simulation model with a modern enterprise geographic information system (GIS). This will provide a science-based tool that can be used to support development of energy resources in the Fayetteville Shale region of Arkansas
- Ground Water Protection Research Foundation, Oklahoma City, Okla.—This project will develop a new hydraulic fracturing module as an add-on to the well known Risk-Based Data Management System. The module will assist regulators and operators in enhancing protective measures for source water and streamlining the well-permitting process.
- Geological Survey of Alabama, Tuscaloosa, Ala.—The primary objective of this research is to analyze and develop strategies for water management in the CBM reservoirs of the Black Warrior basin. The study will develop a large, high-quality database and GIS that will provide a basis for more efficient development of CBM and identification of beneficial uses of produced water.
- Altela Inc., Albuquerque, N.M.—This project will demonstrate that the AltelaRain technology can be successfully deployed in a cost-effective manner to treat the produced and flowback water from Marcellus Shale, and that it can operate within state and federal regulatory requirements.
- University of Pittsburgh, Pittsburgh, Pa.—This project will evaluate the potential for combining and treating two waste streams (flowback water and acid mine drainage) for reuse as a frac fluid, and will also develop novel viscosity modifiers for water high in total dissolved solids.
- Texas Engineering Experiment Station, College Station, Tex.—This project will identify an efficient and cost-effective pretreatment methodology for use in processes employed to treat and reuse field-produced brine and fracture flowback waters. The project aims to develop and demonstrate a mobile, multifunctional technology specifically for pretreatment of brine.

The total proposed value for all selected projects is $10.2 million (DOE share: $6.9 million).

DOE Selects Recipient to Transfer Oil and Natural Gas Innovations

The Department of Energy (DOE) has awarded to the Petroleum Technology Transfer Council (PTTC) funding of up to $4 million to disseminate the newest, most energy-efficient and cost-effective innovations, ideas, tools, and knowledge developed in the realm of oil and natural gas by researchers at DOE's National Energy Technology Laboratory (NETL) and other organizations.

In order to ensure that the latest oil- and natural gas-related ideas, technologies, and innovations are of service to our country as quickly as possible, they must be transferred to stakeholders—such as independent operators, small producers, academic researchers, and technology developers—to empower them to make timely, informed technical and business decisions.

Through this funding, which may be extended for as much as five years, PTTC will collaborate with NETL's Strategic Center for Natural Gas and Oil and others to accomplish the critical goal of supplying a broad spectrum of stakeholders within the oil and gas industry with the how, where, and when appropriately applied technologies can help them solve problems and realize opportunities that will increase production of oil and natural gas in an environmentally sound manner.

PTTC was first organized in the early 1990s as a joint Federal, State, and Industry collaboration to provide the oil and natural gas industry, primarily independent operators and small producers, with improved access to the most advanced and underutilized technologies. PTTC has served as a key outreach organization for U.S. independent oil and natural gas producers, continuously developing its technology transfer expertise and expanding its role as a liaison between the research and development community and independents in all areas of the country.

Goals of this funding opportunity include ensuring that:

- DOE's and industry's technology and knowledge are appropriately publicized to the industry at large;
- The value of DOE and industry products, expertise, and capabilities are fully realized by all stakeholders;
- Successful technologies are commercially deployed to all stakeholders in order that, appropriately applied, these can assist them in solving problems and realizing opportunities that will increase production of domestic oil and natural gas in an environmentally responsible manner;
- And, that sustainable, reliable, and affordable supplies of domestic natural gas and oil resources are made available to meet our country's energy needs.

PTTC plans to transfer technology to the oil and gas industry using traditional outreach tools such as workshops, the web, and publishing information in the various oil- and gas-related trade journals as well as using more novel tools such as webinars, distance learning, and social networking. Strong alliances with universities, geological surveys, trade associations, and professional societies will enhance PTTC's capability to leverage the proposed technology transfer activities. PTTC will provide over $2.2 million in cost share over the five-year period.

RPSEA Selects Projects for the 2008 Ultra-Deepwater Program

The Research Partnership to Secure Energy for America (RPSEA) has selected 12 projects for negotiations leading to an award under the 2008 Ultra-Deepwater Program focused on increasing the supply of ultra-deepwater and unconventional natural gas and other petroleum resources.

"These twelve projects continue to build the integrated research portfolio envisioned by the 2007 and 2008 approved Annual Plans for the Ultra-Deepwater and Unconventional Natural Gas and Other Petroleum Resources Research and Development Program to develop technologies and architectures for operations in ultra-deepwater," said RPSEA President C. Michael Ming. "They add to the 17 projects selected for the 2007 Ultra-Deepwater Program. This Program is designed to bring the resources of America's leading universities, research institutions and technology innovators to bear on the development of domestic resources in water depths of 1,500 meters or greater by reducing costs, increasing efficiency, improving safety and minimizing environmental impacts."

While awards under the RPSEA Ultra-Deepwater Program are open to any U.S.-based organization, most projects involve a team consisting of researchers along with producers or service companies that are in a position to evaluate and apply new technology. Each proposal must provide a minimum of 20 percent cost share, with up to 50 percent for field demonstration projects.

The selected projects are as follows:

- Coil Tubing, Drilling and Intervention Systems Using Cost Effective Vessel
  Project Leader: Nautilus International, LLC
  Additional Project Participants: GE Oil & Gas; NOV CTES; INTECSEA; Tidewater Marine, LLC; The University of Tulsa; Texas A&M University; General Marine Contractors; Huisman Equipment BV
- New Safety Barrier Testing Methods
  Project Leader: Southwest Research Institute
- Riserless Intervention System (RIS)
  Project Leader: DTC International
  Additional Project Participants: Superior Energy Services; NOV Texas Oil Tools; Deepwater Research, Inc.; Det Norske Veritas (USA)
- Advanced Steady-State and Transient, Three-Dimensional, Single and Multiphase, Non-Newtonian Simulation System for Managed Pressure Drilling
  Project Leader: Stratamagnetic Software, LLC
- Technologies of the Future for Pipeline Monitoring and Inspection
  Project Leader: The University of Tulsa
  Additional Project Participant: T.D. Williamson, Inc.
- Wireless Subsea Communications Systems
  Project Leader: GE Global Research
  Additional Project Participant: Northeastern University

- Replacing Chemical Biocides with Targeted Bacteriophages in Deepwater Pipelines and Reservoirs
  Project Leader: Phage Biocontrol, LLC
  Additional Project Participants: Texas A&M University; Shell International Exploration & Production; ConocoPhillips Company; Petrobras America, Inc.; Halliburton; Nalco Company; Multi-Chem Corporation; BJ Services Company; Champion Technologies, Inc.; Intertek Group plc; INTECSEA; Livermore Instruments, Inc.

- Enumerating Bacteria in Deepwater Pipelines in Real-Time at a Negligible Marginal Cost Per Analysis: A Proof of Concept Study
  Project Leader: Livermore Instruments, Inc.
  Additional Project Participants: Phage Biocontrol, LLC; Texas A&M University; ConocoPhillips Company; Shell International Exploration & Production; Petrobras America, Inc.; Halliburton; Nalco Company; Multi-Chem Corporation; BJ Services Company; Champion Technologies, Inc.; Intertek Group plc; INTECSEA

- Fiber Containing Sweep Fluids for Ultra-Deepwater Drilling Applications
  Project Leader: The University of Oklahoma
  Additional Project Participant: M-I SWACO

- Heavy Viscous Oils PVT for Ultra-Deepwater
  Project Leader: Schlumberger Limited

- Early Reservoir Appraisal, Utilizing a Well Testing System
  Project Leader: Nautilus International, LLC
  Additional Participants: Knowledge Reservoir, LLC; Expro International Group Ltd.; General Marine Contractors LLC; INTECSEA; Louisiana State University; The University of Tulsa; Texas A&M University; GE Oil & Gas; Tidewater Marine, LLC

- Ultra-Reliable Deepwater Electrical Power Distribution System and Power Components
  Project Leader: GE Global Research
  Additional Participants: Texas A&M University; Rensselaer Polytechnic Institute; GE Oil & Gas

Funding for the projects is provided through the "Ultra-Deepwater and Unconventional Natural Gas and Other Petroleum Resources Research and Development Program" authorized by the Energy Policy Act of 2005. This program—funded from lease bonuses and royalties paid by industry to produce oil and gas on federal lands—is specifically designed to increase supply and reduce costs to consumers while enhancing the global leadership position of the United States in energy technology through the development of domestic intellectual capital. RPSEA is under contract with the U.S. Department of Energy's National Energy Technology Laboratory to administer several elements of the program. RPSEA is a 501(c)(3) nonprofit consortium with more than 145 members, including 25 of the nation's premier research universities, five national laboratories, other major research institutions, large and small energy producers and energy consumers. Additional information can be found at www.rpsea.org.

Upcoming Meetings and Presentations

October 15, 2009: PTTC Workshop on Water/Gas Shutoff and Conformance Control – Knowing What To Do/Where – Casper, WY. Contact: 303-273-3107.

October 20–21, 2009: PTTC Workshop on Property Taxes. Day long workshop held in Long Beach and Bakersfield, CA on successive days. Contact PTTC West Coast at (661) 635-0557 or Email (pttcwestcoast@cccogp.org) for more information.

October 26-30, 2009: A talk on "Time Reversal Focusing for Pipeline Structural Health Monitoring" will be given at the 158th Meeting of the Acoustical Society of America, to be held in San Antonio, Texas, October 26-30, 2009. The talk is related to NETL project DE-NT0004654, Instrumented Pipeline Initiative. View project information. http://www.netl.doe.gov/technologies/oil-gas/NaturalGas/Projects_n/TDS/TD/04654_PipelineInitiative.html

October 27, 2009: PTTC Workshop on Fundamentals of Waterflood Design – Wichita, KS. Contact: 785-864-7396.

October 28, 2009: PTTC Workshop on Waterflood Systems and Operations – Wichita, KS. Contact: 785-864-7396.

October 29-30, 2009: PTTC Short Course on Fundamentals of Waterflooding: Day 1 – Design and Implementation; Day 2 – Operations and Management – Wichita, KS. Contact: 785-864-7396.

November 3-5, 2009: The 16th Annual IPEC Petroleum and Biofuels Environmental Conference, Renaissance Houston Hotel, Houston, TX. The Integrated Petroleum Environmental Consortium (IPEC) is a joint effort of four major research universities: The University of Tulsa, The University of Oklahoma, Oklahoma State University, and The University of Arkansas. See website for more information.

NETL

the ENERGY lab