

E&P Focus

Spring 2010

Oil & Natural Gas Program Newsletter



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Stripper Well Consortium Aids America's Small Producers

The Stripper Well Consortium (SWC) is an industry-driven consortium focused on the development, demonstration and deployment of new technologies needed to improve the production performance of natural gas and petroleum stripper wells. The term stripper well denotes a well producing no more than 10 barrels of oil per day or 60,000 cubic feet of gas per day. One out of every six barrels of crude produced today comes from a stripper well. Over 85 percent of the total number of U.S. oil wells are now classified as stripper wells. Together, these nearly 400,000 wells produce around 800,000 barrels of oil per day or nearly 10 percent of lower-48 production. Many of these wells are marginally economic and at risk of being prematurely abandoned, leaving significant amounts of oil unrecovered. In addition, there are some 320,000 natural gas stripper wells in the U.S., accounting for over 1.7 trillion cubic feet of annual production, or 9 percent of the natural gas produced in the lower 48. *(Continued on page 3.)*



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Commentary



For three decades the Department of Energy (DOE) has invested in RD&D designed to accelerate the application of technology to help independent producers more effectively develop the Nation's oil and natural gas resources. The investment has paid off. For example, DOE research carried out during the late 1970s and 1980s provided the first scientific assessment of Appalachian gas shale resources, and also helped speed acceptance of a number of technologies that are now commonly employed by independent natural gas shale developers (e.g., horizontal drilling and high volume hydraulic fracturing in gas shales, detailed natural fracture analysis, and microseismic fracture mapping). According to Dr. Terry Engelder, a Marcellus Shale authority at Pennsylvania State University, "A look back at the data and innovations generated by the program makes it clear that the Eastern Gas Shales Program was simply ahead of its time ... it took 25 years before its value became clear."

Research conducted and managed by the National Energy Technology Laboratory (NETL) continues to focus on the problems of independent producers that are active in the Nation's more mature producing basins. This issue of *E&P Focus* provides some examples: new solutions for the sort of problems stripper well operators face every day, online tools to help reduce regulatory compliance costs for small producers in New Mexico, and research that can help extend the life of mature fields through enhanced oil recovery techniques like chemical flooding and carbon dioxide injection.

We fully expect that the exciting research that NETL has completed in recent years and continues today will make as big a difference over the next two decades as past successes have. Based on recent preliminary analysis by NETL and Advanced Resources International, there appears to be a significant opportunity for CO₂-EOR/Storage throughout the country and exploiting this opportunity will necessarily require additional partnering with independent operators. A summary of this screening analysis is provided on page 18.

NETL welcomes and appreciates the collaborative efforts of industry partners in the development of these new technologies, providing cost share, data, expertise and access to well locations. We are continuing to look for ways to further enhance this collaborative approach to meeting the technology needs of independent producers, as we move forward.



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

SWC REQUEST FOR PROPOSALS NOW OPEN.

The Stripper Well Consortium is seeking proposals from Full and Supporting Consortium members for R&D funding for the period 1 September 2010 to 31 August 2011. The proposed projects must identify new technologies that have the potential to significantly improve production from domestic petroleum and natural gas stripper wells or fields, significantly reduce operator costs, or improve the environmental footprint of stripper well operations. Submissions must propose research in one of four areas: reservoir remediation, characterization and operation; well-bore clean-up; surface and collection optimization; and, environmental/energy efficiency. The consortium anticipates making four to five awards at funding levels from \$75,000 to \$125,000 although higher valued projects will be considered based upon available funding. The deadline for submission of proposals is 4:00 PM (Eastern Standard Time) on June 3, 2010. Full details are available at <http://www.energy.psu.edu/swc/fundedopp.html> or from the Stripper Well Consortium, The Pennsylvania State University, C-211 Coal Utilization Laboratory, University Park, PA 16802-2323.

(Continued from page 1.) To ensure the nation's energy supply, and to forestall premature abandonment of stripper wells, SWC was established on September 30, 2000 through a cooperative agreement between the U.S. Department of Energy (DOE) and The Pennsylvania State University (Penn State). The initial agreement provided approximately \$3 million of base funding over a three year period to develop technologies for America's stripper wells. The agreement has been continued with additional funding. It provides Penn State with overarching management responsibilities for the consortium.

SWC is comprised of natural gas and petroleum producers, service companies, industry consultants, universities and industrial trade organizations. The Strategic Center for Natural Gas and Oil (a division of the National Energy Technology Laboratory of DOE), the National Petroleum Technology Office and the New York State Energy Research and Development Authority provide base funding and guidance to the consortium. By pooling financial and human resources, the SWC membership can economically develop technologies that will extend the life and production of the nation's stripper wells.

Research with the SWC is conducted in three, broad areas: reservoir remediation, wellbore clean-up and surface system optimization. Research outside these three areas may be considered pending approval of the program sponsors. Specific research proposals are developed by SWC members and require a minimum of 30 percent cost share from project participants.

The SWC currently has 97 members. The membership includes companies and organizations from 23 states, plus the District of Columbia and Canada, with operations in many other states. An Executive Council, appointed by the SWC membership, selects research projects from those proposed. The process of having industry develop, review and select projects for funding ensures that the SWC conducts research that is relevant and timely to the oil and gas industry.

For the period 2001 through September 2010, the SWC committed over \$9.7 million to co-fund 92 projects. This includes five proposals, totaling about \$650,000 that were selected for co-funding by the SWC for the October 2009 to September 30, 2010 funding cycle. Related projects undertaken by DOE support technology development and technology transfer projects within the SWC.

In the pages that follow, we will review two projects now underway within the Stripper Well Consortium, each aimed at improving stripper well operations and production and lowering the environmental impact of stripper wells. These projects are: Well Pump-Off Controls and Brine Contaminated Soil Remediation.

SWC Project 1: Improved Pump-Off Controls Help to Maximize Production

Beam pumped wells wrestle with subtle fluid level issues that can make production optimization challenging. If the fluid level in the wellbore is allowed to increase, the increased hydrostatic pressure on the producing reservoir can inhibit the inflow of formation fluids, thereby lowering production. If, on the other hand, beam pumped wells are “pumped off” (i.e., all the fluid is pumped from the wellbore), the pump and rods operate without liquid lubrication, leading to excessive wear on fluid seals and moving parts. This situation can also result in an unbalanced pumping system. Neither of these scenarios is desirable. In the ideal situation, the beam pumping unit would automatically shut off just before all the fluids had been pumped from the wellbore and then begin operation again when the fluid level in the wellbore reaches an optimal level. Until recently, this ideal has been approached through the use of trial-and-error manipulation of timers, with mixed degrees of success.

Pre-Pump-Off Controls, a set of technologies developed by Oil Well Sentry, Inc. with support from the Stripper Well Consortium, promises to eliminate troublesome fluid level issues in beam pumped wells. The system works by monitoring each pump stroke for the normal level of fluid refilling the working barrel at the bottom of the well. When the normal level decreases because pump-off is approaching, the motor or engine stops the cycle in 2-3 pump strokes (Figure 1).

Closely monitoring the fluid levels allows for a balance to be achieved between crude oil production time (pumping to pump-off) and the number of pumping cycles. Typically, using the Well Sentry system allows for an increase in the number of cycles per day, with the pumping times tailored to actual well conditions. Although the pumping time per cycle may be decreased, net production can be significantly increased while energy consumption can be decreased by 30 percent.



Figure 1. A fluid level sensor is mounted on the bridle cables below the horse's head.

In addition to stroke-by-stroke fluid level monitoring, the technologies employ a meter that records the exact time of actual production in 6 minute increments. If the meter is checked and reset daily, the average daily pumping times can be compared and a "normal" production time determined for future operation. This reduces the need for physical observation of each well by the lease operator and eliminates guesswork as to how to adjust the system.

Several sensor packages are available in the Well Sentry line, each tailored to specific well parameters. The fluid level sensor measures the fluid level in the working barrel of the pump. The unit mounts on the bridle cables below the horse's head (Figure 1) and stops the pump operation when the plunger fails to hit fluid high in the working barrel but contacts fluid near the bottom of the barrel.

A second set of sensors are installed in the flowline coming off the wellhead and measure fluid volume for each stroke (Figure 2). The production cycle is ended when the average volume of the fluid pulse decreases. Each of the sensors is sized to match output pressure and volume.

A third type of sensor monitors pressure of production fluids on each stroke against the backpressure valve on wells that produce associated gas. Back pressure valves are used to prevent gas from entering the pump and production tubing. The sensor terminates the production cycle when the back pressure valve fails to open as usual during a normal pump stroke due to less fluid being pumped. All sensors are accompanied by a control box containing a timer, shut down controls and monitoring units.

The Pre-Pump Off controls have been configured to work with natural gas or gasoline powered engines as well as electric motor pump units. In all models, solar panels are being designed to replace batteries for operating the controls.

Support from the SWC enabled Oil Well Sentry to refine the system and to develop and test additional sensors and controls. The system is currently commercially available (see <http://oilwellsentry.com>).



Figure 2. An FP-1 Sensor mounted in the flowline downstream of the wellhead.

SWC Project 2: Brine Contaminated Soil Remediation

Salt contamination of soils is a serious environmental issue facing independent oil and gas producers. RTA Systems, Inc., with support from the SWC, has tested a product that promises to provide a faster, easier and potentially more cost-effective way to remediate salt damaged soils at new and old brine contaminated sites. The project supported by SWC involved laboratory testing of RTA System's soil amendment product, followed by mini field pilot tests for verification. The results are promising.

Sodium chloride in produced brine, if spilled via tank or line leaks, can be very damaging to soils. Clay soils in particular contain calcium and magnesium ions that are preferentially exchanged for the sodium ions. This causes the clay particles to swell, reducing the soil pore space and permeability, and making it difficult to flush the sodium from plant root areas. The soil becomes dense, impermeable to water, and easily eroded. Vegetation dies due to sodium toxicity and reduced water in the root zone.

Current methods to remediate sodium-affected soils are time consuming, frequently ineffective and expensive. One common treatment, adding gypsum alone or with fertilizer, is usually insufficient to quickly promote grass growth on soils badly damaged by produced water.

RTA Systems developed a soil amendment product with a calcium source that is 70 times more water-soluble than gypsum and that acts in concert with a proprietary Multifunctional Component (MC). The product:

- 1) Exchanges calcium for, and chelates with the damaging sodium in the clay,
- 2) Provides organic material to the soil for plant growth,
- 3) Assists in rejuvenation of the bacterial populations,
- 4) Enhances nutrient transport into the plant, and
- 5) Improves water wetting of the soil.

The MC can also chelate heavy metal contamination and absorb low levels of light hydrocarbon contamination.



Figure 1. Bartlesville Site Prior to Remediation.



Figure 2. Bartlesville Site After Remediation, July 14 2009.

Application involves three steps: 1) Tilling the soil, 2) Spreading dry or liquid solutions of the RTA amendment and fertilizer, and 3) Re-tilling to disperse the amendment into the soil. Watering the amendment into the soil may be required if rainfall is not prevalent.

Laboratory Evaluation—Laboratory testing was performed using a matrix of soil amendment formulations in contaminated soils sampled from two planned field tests in Oklahoma and New York. The contaminated soils were characterized (Table 1) and amendment formulations were customized to treat the soils in the laboratory. The Alexander, NY soil has extremely high calcium and magnesium concentrations compared to the sodium, which is still four times that found at the Oklahoma site.

The control experiments with no amendment treatment resulted in no grass growth. Application of the MC alone generally gave reasonably good results for both soils. Improved results occurred in the case of the Oklahoma soil when the MC and calcium were combined, however with the NY soil inclusion of the calcium amendment with the MC did not appear to make a difference.

Table 1. Soil Characterization From Field Test Sites.

| | Bartlesville, OK | Alexander, NY |
|---------------|------------------|------------------|
| Sodium Ion | 2,070 ppm | 8,840 ppm |
| Calcium Ion | 2,000 ppm | 89,200 ppm |
| Potassium Ion | 17.1 ppm | 1,500 ppm |
| pH | 6.90 | 7.75 |
| SAR | 11.80 | 6.81 |
| ESP | 13.82 % | 8.03 % |
| CEC | 8.52 meq/100 g | 544.74 meq/100 g |

SAR - Sodium Adsorption Ratio
 ESO - Exchangeable Sodium Percentage
 CEC - Cation Exchange Capacity



Figure 3. Close-up showing Bermuda Runners on September 29, 2009.



Figure 4. Alexander, NY Site Prior To Remediation.

Field Tests—The Bartlesville contaminated site area measured approximately 2,140 square feet and was covered with a crusty, white, salt-like layer (Figure 1). The treatment was based on the laboratory-derived formulation that included the MC, calcium, and 10-20-10 fertilizer. The Bartlesville site was treated on July 14, 2009 by tilling the soil approximately 6 inches deep, applying the soil amendment and re-tilling the soil (Figure 2). By August 14, most of the salt contamination had disappeared. Two-inch squares of Bermuda grass sod were sprigged into the soil and by September the grass had begun to spread (Figure 3). A shorter time period between remediation of the soil and when the grass seed can be planted, germinate, survive and reestablish vegetation in the affected soils is perhaps the greatest added value of using this new soil amendment.

The Alexander, NY site, area measured approximately 1,000 square feet (Figure 4). The soil amendment formulation for NY utilized a slightly different MC at a higher concentration than was used in Bartlesville. The calcium component was unnecessary due to the high calcium and magnesium ion concentrations already in the soil. The project was not remediated until late in the season (October 22, 2009) with the soil amendment and fertilizer, and planted to rye grass (Figure 5). Another seeding is planned in the spring of 2010 if necessary.

Conclusions—The Bartlesville site was fairly low in contamination severity at roughly 2,000 ppm each of sodium and calcium ions, whereas, the NY site was high in sodium (9,000 ppm), and exceptionally high in total calcium and magnesium ion content (100,000 ppm).

The RTA soil amendment cost estimate for the Bartlesville site was only 20 percent higher than that for conventional gypsum and fertilizer, \$0.016 per square foot versus \$0.013 per square foot.

The results of the Alexander field test are not available at this time, but based on the laboratory tests, a similar shortened remediation time frame is expected. If so, the Alexander site formulation would provide a more significant economic benefit. The cost of the RTA amendment was \$0.047 per square foot, compared to a cost of \$0.223 per square foot for a traditional gyp-fertilizer system in the high calcium-magnesium soil, almost a five-fold difference in price. Note that the RTA Systems MC amendments used in the two field tests are slightly different.

Also, these cost estimates are based on the purchase of small volumes of the amendment components, gypsum, and fertilizer. Final RTA Systems commercial pricing for a soil amendment product has yet to be determined.

The most significant advantage of the RTA Systems product for remediating brine-contaminated soil may be the relative speed of remediation over traditional gypsum methods. Economics for these treatments suggest that the RTA amendment is cost competitive or cheaper than conventional practices. For more information, contact RTA Systems in Oklahoma City, OK at 405-455-5166.



Figure 5. Alexander, NY Site After Remediation.

New Online Portal Will Help Small Producers with Pit Siting and Regulatory Compliance

In July 2008, the New Mexico Oil Conservation Division (NMOCD) finalized changes to management rules regulating pits, closed-loop systems, belowgrade tanks, and sumps used in connection with oil and gas operations. With the adoption of these “Pit Rules”, New Mexico’s small producers have experienced an increase in compliance data required for pit applications, which has dramatically affected both application preparation time and time for regulatory review of those applications. While all producers in New Mexico face increased compliance time and costs, small producers, with limited specialized staff and ability to absorb substantial, unexpected expenses, are most strongly affected.

The New Mexico Petroleum Recovery Research Center (a division of the New Mexico Institute of Mining and Technology) has been funded by DOE’s National Energy Technology Laboratory through the Energy Policy Act of 2005, Section 999 research program administered by the Research Partnership to Secure Energy for America (RPSEA), to create The New Mexico Pit Rule Mapping Portal. This online system will generate maps of potential site regulatory issues using government recommended data, reducing the time needed for evaluation, preparation and review of C-144 forms and attachments, and enabling better determination of optimal locations for pits and tanks with respect to current siting criteria. Both the Independent Petroleum Association of New Mexico and NMOCD are partners in this effort and have committed resources to further the project.

The project has addressed additional compliance and permitting requirements by making available online a variety of data deemed acceptable by NMOCD. Efforts have been made to provide comprehensive coverage for the entire state, which includes two major producing areas, the San Juan and Permian Basins. GIS layers have been presented for a number of relevant factors including subsurface water depth, surface geology and soil maps. Additional compliance data can be obtained from maps of flowing and intermittent watercourses, existing water wells using records from the New Mexico Office of the State Engineer, subsurface mineral usage or other subsurface rights, municipal boundaries, 100-year floodplains and other relevant engineering data, such as ground stability and calculated surface slope data (Figure 1). Finally, access to USGS topographical sheet data and aerial photo mosaics can be used to determine the existence of, and distance to, nearby structures (Figure 2).

Software developed for the project currently allows mapping for specified locations and provides the user with maps showing compliance features in the vicinity of their proposed drilling or workover sites. As the project continues, necessary forms and reporting/permitting requirements are being catalogued and will be used to create a digital version of the C-144 form. It is anticipated that the software will provide a list of warnings that will anticipate NMOCD questions about a selected location with prompts on where to find supplemental data. The system could save operators time by helping them avoid repeat applications and enabling better estimates of production costs, end-of-well life, and other issues for a particular location.

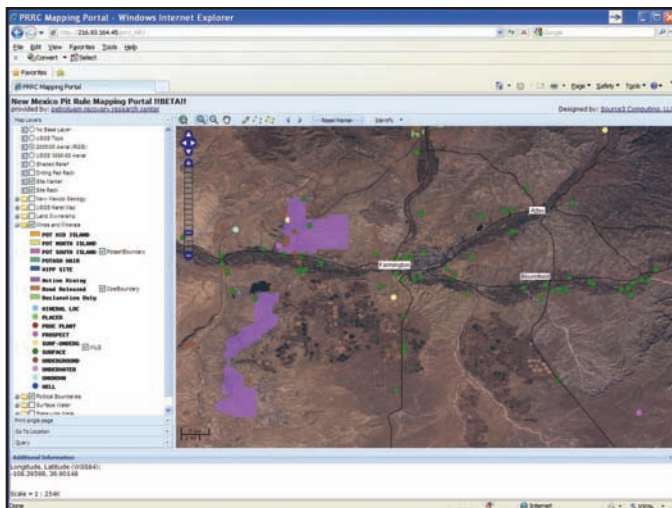


Figure 1. Map with overlay showing proximity of area of interest to subsurface mineral usage.

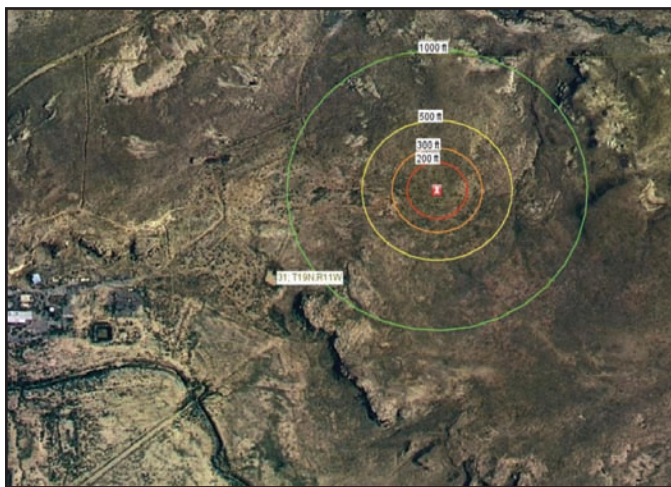


Figure 2. Map with areal photo overlay showing proximity of area of interest to existing infrastructure.

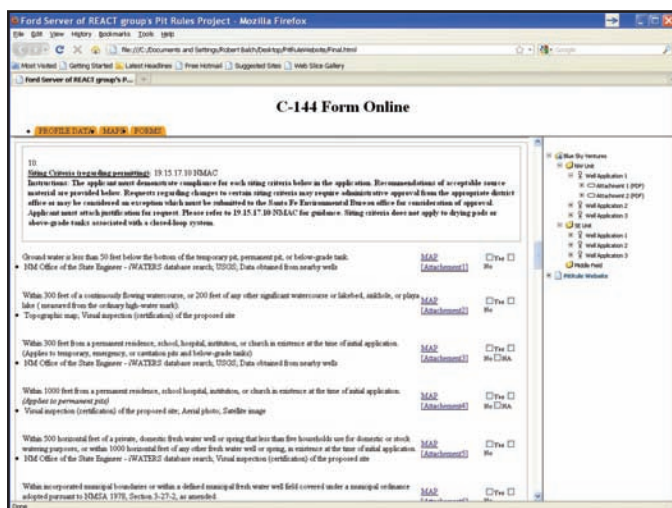


Figure 3. The electronic NMOCD C-144 form on the portal. The application may be submitted electronically, with questions may be answered and supporting maps generated and attached to document the site application.

When fully functional, the GIS based New Mexico Pit Rules Mapping Portal will overlay maps for the parameters discussed above on regional, area and local map scales. The portal will include a fairly standard toolbar with a Map Layers tab, in addition to common zoom, query, draw and print tabs. The toolbar also will allow the user to identify existing wells by USGS, OSE or NMOCD identification systems. The user will be able to choose the well type and select a rectangular area on the map. Wells within the selected region that match the type of well selected will be identified. At present, one type of well may be selected at a time.

To begin to develop map attachments for the C-144 form and application process in the portal, the user will click directly on the map, or enter the location using Township-Range, Latitude-Longitude, or an address to bring up the area of interest. Once the area of interest is identified, the user will select layers under the Map Layers tab to insert layers on the map. The user will be able to select the entire folder's content or expand the folder and select individual map layers. Using this feature, the user will be able to create a map of all relevant features of interest in proximity to the planned site that uses NMOCD suggested data sources.

A further function of the portal will be the ability to complete C-144 forms electronically using data derived from a layered map previously or interactively created using the portal (Figure 3). Using radii corresponding to the allowable proximity to features such as existing wells, subsurface water sources, urban areas, and other sensitive features, the map will automatically generate attachments for corresponding sections of the C-144 form.

The New Mexico Pit Rules Mapping Portal is currently in beta test by operators and regulators. Final adjustments are being made based on feedback from the users. The Portal is expected to greatly ease the burden of siting pits and other storage structures for New Mexico oil and gas operators. The portal concept can be made available for modification to match the siting requirements of other states, further benefiting America's small producers.

For more information, contact Chandra Nautiyal, NETL Project Manager, at Chandra.Nautiyal@netl.doe.gov.

Identifying Where Kansas Producers Should Try Chemical EOR

As part of the National Energy Technology Laboratory's (NETL) oil and natural gas R&D program, The University of Kansas is carrying out research to enable independent oil producers to accurately assess whether oil production from their reservoirs can be enhanced by "next generation" chemical flooding. The research includes: classifying Kansas reservoirs amenable to flooding; establishing selection criteria to identify the oil leases that are the best candidates for chemical flooding; collecting crude oil samples and performing laboratory work to design chemical formulations for specific oils/reservoirs; conducting reservoir simulations to determine the expected response to chemical flooding in the selected fields; and evaluating the economics of future field applications.

Selecting Reservoirs

Kansas reservoirs were classified using geological characteristics such as lithology, trap, and drive mechanisms. Together, the Arbuckle Group reservoirs and the Mississippian reservoirs have provided 52% of the oil production in Kansas (Figure 1). However, the research team found that neither of these is amenable to chemical flooding.

On conducting interviews with several of the largest independent oil producers in Kansas, researchers discovered that the frequency of waterflooding in a specific rock unit was the best indicator of favorable characteristics for chemical flooding. Commonly waterflooded formations in central and western Kansas include the Missourian Lansing and Kansas City groups, the Pennsylvanian Marmaton, Cherokee, and Marrow groups, the Mississippian Chester Group, and the Ordovician Simpson Group.

Since chemical flooding is a slug-type process, whereby residual oil is mobilized and displaced to production wells by the chemical slug moving

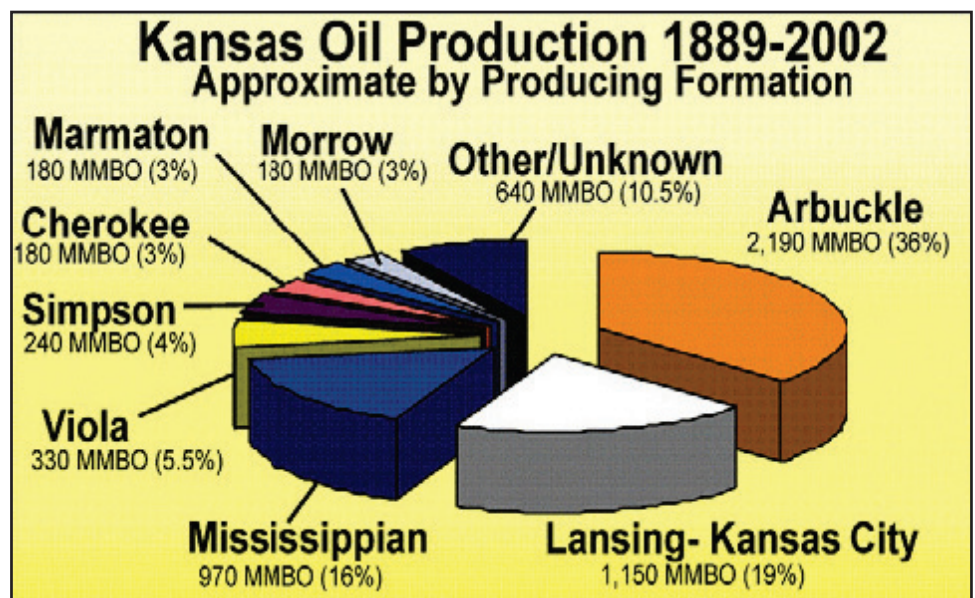


Figure 1. Oil production in Kansas by stratigraphic unit (Kansas Geological Survey).

through the reservoir, maintaining the integrity of the slug is crucial. Good sweep efficiency during a waterflood suggests that the fluid-flow characteristics of the reservoir are sufficient to maintain slug integrity and therefore is considered to be an indicator that a chemical flooding application will be successful. As detailed fluid-flow characteristics have not typically been determined for most mature Kansas reservoirs, other selection criteria must be employed to identify reservoirs that are the best candidates for chemical flooding: oil recovery response; waterflood age and well status; and evidence of flood containment.

During waterflooding, good volumetric sweep is indicated by a significant and sustained oil recovery response (Figure 2). Such sweep efficiency within a reservoir points to it being a strong candidate for chemical flooding. Under the second criterion, a reservoir that has a very mature waterflood, where the majority of wells have already been plugged, is not a strong candidate for chemical flooding.

To be successful, a chemical flood must be contained within a specified pattern area. Boundaries must be clearly defined, and there should be no evidence of communication between multiple zones in a reservoir.

Although a database of roughly 5800 oil reservoirs in Kansas was constructed from publically available data (now available online at <http://www.torp.ku.edu>), the uncertainty of historical production data due to misallocation of the oil produced in a field to various producing zones made the use of the database alone as a selection tool problematic. The research team found that contacting Kansas oil producers to discuss potential candidate reservoirs was much more fruitful. Five leases were chosen for further study. The producing reservoirs in the fields that were selected include the Lansing-Kansas City, Cherokee Lime, and Simpson sand.

Testing of Oil Samples from Selected Leases

Oil samples were obtained from three of the selected leases. In the laboratory, the crude samples were mixed with chemical formulations

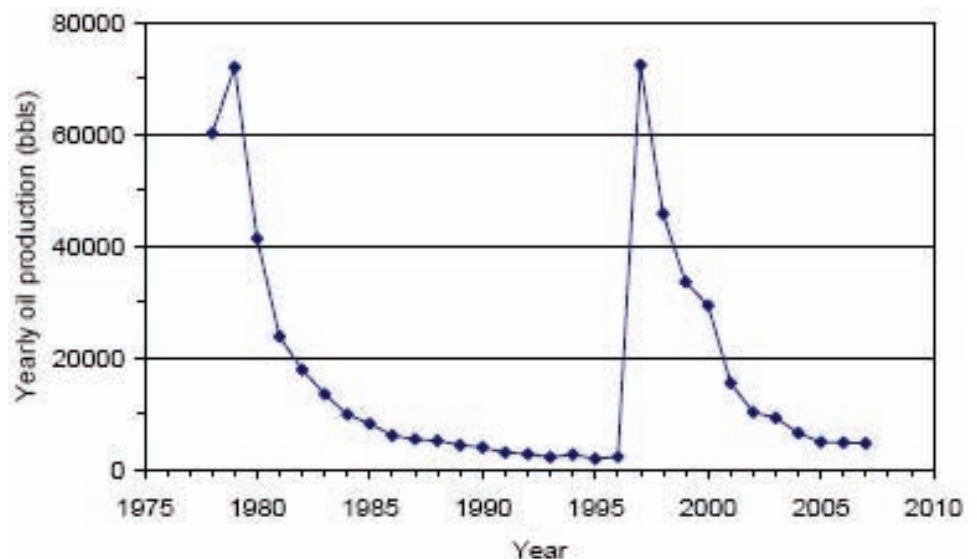


Figure 2. Yearly oil production of the Trembley Lease in Reno County showing evidence of an effective water flood and potentially good sweep efficiency.

and then allowed to equilibrate at the reservoir temperature. Upon equilibration, the resultant phase behavior of the mixture was observed visually. Investigators searched for systems that: form middle-phase microemulsions that coalesce and equilibrate quickly; are not adversely affected by the reservoir brine, do not form viscous phases or macroemulsions; and where the aqueous surfactant mixture remains stable as a single phase at both ambient and reservoir temperature.

Two crude oils from the Trembley and Wahrman leases have had chemical formulations designed for them that display the phase behavior desired for a successful flood. An efficient system using the Wahrman oil was achieved by adding alcohols as co-solvents. Adding alcohols (such as ethylene glycol monobutyl ether or EGBE) to the surfactant allowed the criteria for a one-phase system, at ambient and reservoir temperatures, to be met. At low salinity values, systems are usually one-phase but as water salinity increases, the systems commonly separate into two liquid phases, something that does not enhance recovery. During this investigation, the researchers found that by increasing the concentration of EGBE, they could adjust the phase behavior at reservoir temperature despite higher salinity reservoir water.

Ongoing Work

The ability of the system to mobilize and displace residual oil in porous media is currently being determined in flow experiments using the selected chemical formulations. Various polymers will be added to the selected chemical systems, and the mobility of each of those polymer-surfactant systems will be measured. Berea sandstone cores are being used as the media for testing.

Once flow tests have been completed in the Berea cores, they will be performed in samples of reservoir rock. Field data is currently being identified, collected, and analyzed for the Wahrman and Trembley leases. The Beaver Creek Field, which holds the Wahrman Lease, has been described in detail in a report completed by the researchers. After flow tests have been conducted and chemical formulations have been devised for the reservoirs, simulation of chemical flooding within each reservoir will take place. It is anticipated that the project will be completed in September 2011.

For additional information on this project please contact Virginia Weyland, NETL project manager (281-494-2517 or virginia.weylend@netl.doe.gov).

New Hope for Mature Fields—Effective Partnering to Boost Recovery in the Illinois Basin

NETL is partnering with the Illinois State Geological Survey (ISGS) at the University of Illinois, with cooperation from Rex Energy Corporation, to revive oil production from mature fields in the Illinois Basin by testing a technique known as Alkaline-Surfactant-Polymer (ASP) flooding. The focus of this 3-year effort is on the Bridgeport and Cypress sandstones in the Lawrence Field of the Illinois Basin (Figure 1). Most of the Lawrence field is owned and operated by Rex Energy, who is providing reservoir characterization data and will utilize project results to inform decisions about where to test ASP flooding. The results should prove to be applicable in other sandstone reservoirs where secondary recovery is

stalled, and tertiary recovery needs a boost.

This project arose out of a shared goal, among industry and government entities, to increase oil recovery from mature fields such as the Lawrence Field. The Lawrence Field has produced more than 400 million barrels of oil since its first wells were drilled in the early 1900's, but current production has dwindled to the point where it is marginally economic to continue operating existing wells (Figure 2). The field currently produces with an oil cut of less than 2%, but it contains significant quantities of unrecovered reserves – including residual, bypassed, and unswept oil. Based on laboratory testing, researchers estimate that 130 million barrels of additional oil could be recovered from Lawrence Field reservoirs using ASP flooding.

What is ASP Flooding?

ASP flooding technology has been in existence for more than 20 years and has mainly been used for improved recovery of light crude oils. It is based on the concept of co-injection of 1) an agent that modifies the interfacial tension between oil and water in the reservoir and 2) an agent that controls the mobility of the oil. By

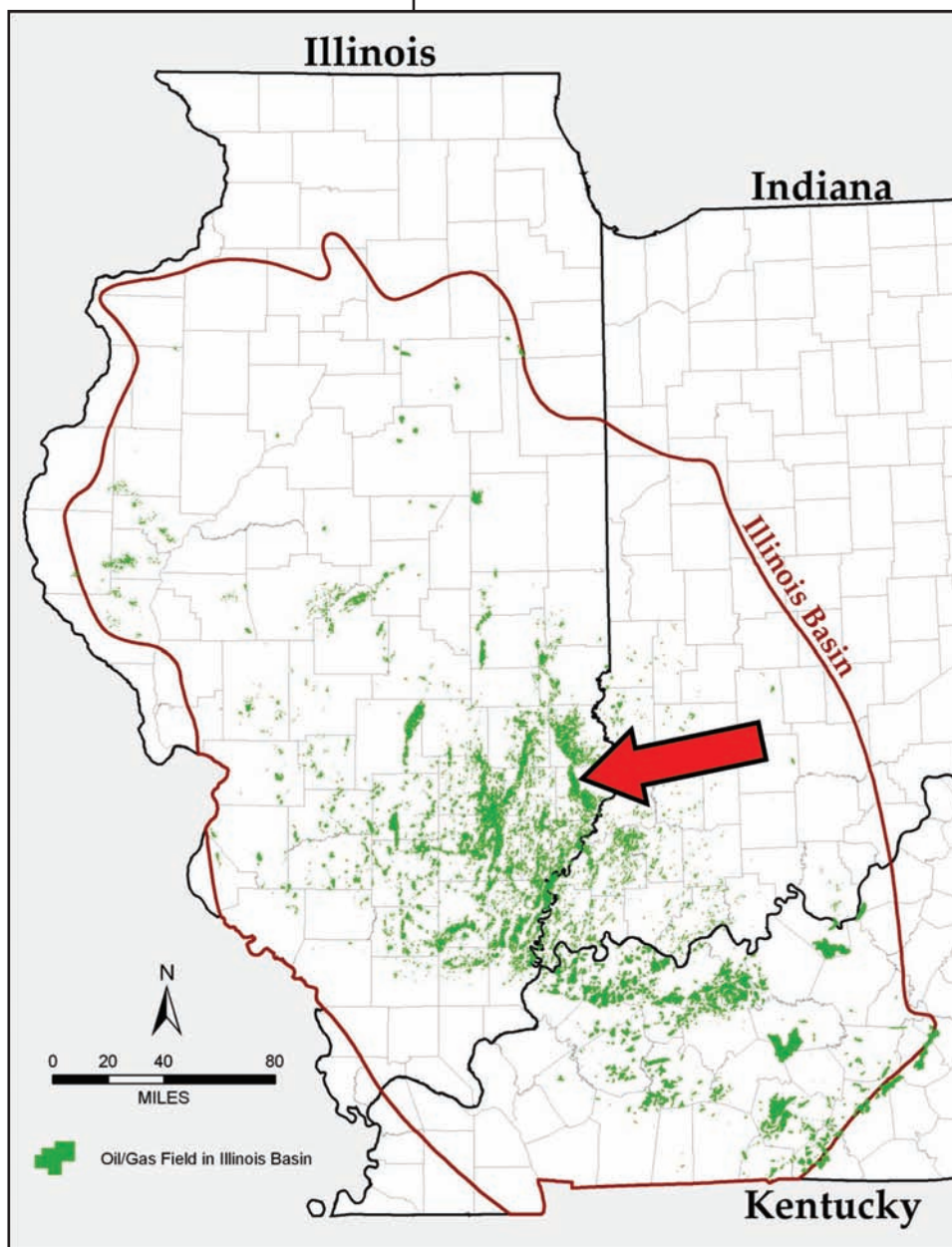


Figure 1. Outline of Illinois Basin and location of Lawrence Field (red arrow).

interacting with the reservoir fluids, the chemical agents cause changes in the relative permeability, rock wettability, and viscosity of the crude oil being displaced. The alkali and surfactant agents serve to reduce interfacial tension, essentially allowing the crude oil to be more efficiently removed from the pore spaces in the reservoir; and the polymer serves to enhance the mobility of residual oil relative to the injectant, so that it can be more efficiently swept from the total reservoir volume.

ASP flooding has been applied successfully in a number of oil fields, with examples in Europe, China, and the U.S. In fact, a related chemical flooding treatment, called the Maraflood™ process (developed by Marathon), was tested in sandstone reservoirs of the Illinois Basin in the 1980's. In those pilot tests, injection of surfactant and polymer into the reservoir resulted in a marked improvement in production, with an increase in the oil cut from 1% to 20%. The main problem with the Maraflood™ treatment was economic – the cost of the chemicals was high relative to the value of the recovered oil. In order for chemical flooding to be worth the investment, it is necessary to formulate the most efficient chemical mixture and, most importantly, to select an optimum reservoir interval for injection.

The Illinois Basin has large stores of residual and bypassed oil, so it seems to be well-suited to chemical flooding. The challenge, however, is that the reservoirs are complex, with variable lithofacies, variable amounts of unrecovered oil, and potential thief zones that are capable of stealing the ASP fluid as it is injected. In order to ensure the success of ASP flooding in the Illinois basin, it is necessary to have a firm understanding of the reservoir geology and to map these reservoir heterogeneities as accurately as possible.

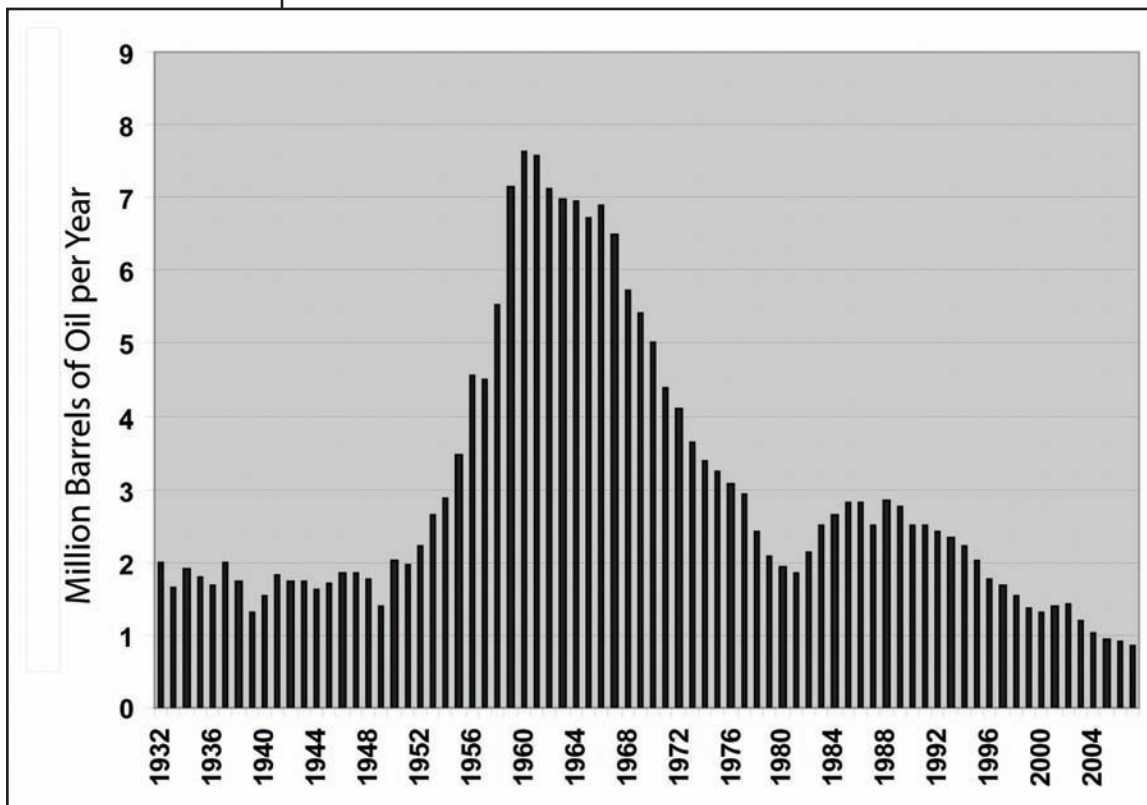


Figure 2. Lawrence field production history. Discovered in 1908, primary production occurred from 1908-1950. The increase in production in the 1950s was due to the introduction of the secondary recovery technique of waterflooding. Deeper drilling and infill drilling slightly increased production in the 1980s.

Understanding the Reservoirs

To this end, the ISGS and Rex Energy are analyzing all available reservoir data for the Pennsylvanian-age Bridgeport sandstones and Mississippian-age Cypress sandstones in a selected area of the Lawrence Field. Most of the unrecovered oil in the Lawrence Field resides in these two sandstone units, and the study area is the location targeted for initial testing of ASP flooding.

The research team has compiled a comprehensive reservoir database for the study area that includes over 2000 geophysical logs, available porosity and permeability data, waterflood and fluid saturation data, and core data. In addition, project geologists have completed detailed petrographic analyses on over 190 samples from cores obtained in this area. These data have been combined into GeoGraphix® to develop a series of maps and cross sections of the reservoir intervals of interest. Core-based sedimentary facies have been correlated to wireline logs to better define facies units seen on the logs.

The Bridgeport and Cypress sandstones have been subdivided into multiple sand intervals, and these intervals are highly compartmentalized. The researchers have mapped multiple sandstone bodies, which are commonly less than 10 feet thick and separated by low-permeability barriers, in some cases formed by regions containing calcite cement (Figure 3). The highest porosity and permeability is typically found in the center of the sandstone bodies.

The research team is now in the process of building digital geological models that can be used as input into a reservoir simulator. Reservoir simulations will be carried out as a means of predicting ASP flooding outcomes for selected zones of Bridgeport and Cypress sandstones in the study area. These reservoir simulations, along with the detailed maps and cross sections that portray lateral and vertical changes in reservoir quality, will be used to select best candidate zones for testing ASP flooding.

Pilot Test

Rex Energy plans to carry out field testing of the ASP flooding technique in the Lawrence Field, based in part on results of these detailed reservoir studies and focusing on the zones identified as most suitable for successful flooding. ISGS will analyze results of field testing and recommend a path forward for expanding ASP flooding to similar fields in the Illinois Basin and elsewhere in the U.S.

Project Impacts

Effective ASP flooding in the Lawrence Field has the potential to produce an additional 130 million barrels of oil. Widespread application of ASP flooding to other mature fields across the U.S. could prove to be a significant step toward extending the lives of low-yield wells and mature fields, where production is just marginally profitable.

This project is a prime example of the effectiveness of NETL working together with regional experts and small independents. In this case, Rex Energy has a financial interest in improving recovery in the Lawrence Field; the ISGS has the experience and knowledge to perform the necessary reservoir characterization; and with financial and technical management support from NETL, the ISGS is able to assist Rex Energy in selecting sites for successful application of ASP flooding in the targeted reservoirs. The project seems likely to result in successful mobilization of significant unrecovered oil from the

Lawrence Field, and the results may spur additional application of chemical flooding in other mature fields in the U.S.

Dr. Beverly Seyler, project PI for the ISGS, notes that industry is really paying attention to Enhanced Oil Recovery (EOR) via ASP flooding. Seyler notes “we held a workshop recently on EOR using chemical flooding and had tremendous interest in this technology, especially from small independent companies -- both within the Illinois Basin and outside the basin. Projects such as this can provide excellent examples of techniques that have broad application, regionally and nationally.”

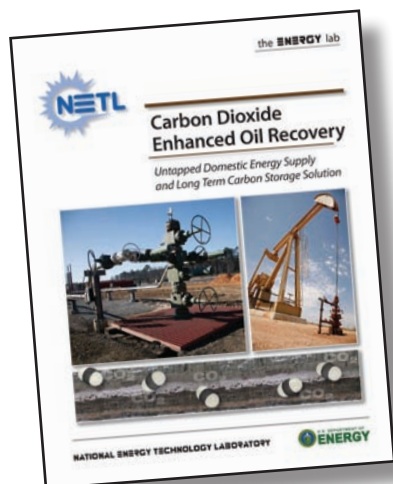
Seyler adds “chemical EOR has huge potential in the Illinois Basin and in numerous other mature basins throughout the U.S. This technique has the potential of reviving many mature fields.”

Contact

For more information on the project, please contact Chandra Nautiyal, NETL Project Manager (chandra.nautiyal@netl.doe.gov).



Figure 3. Core photograph, showing heterogeneity of the Lawrence Field reservoir rocks. Calcite cemented interval at red arrow has very limited porosity and permeability and forms a barrier to fluid flow.



NETL's new "Primer" explaining CO₂-EOR for non-technical readers can be downloaded at [http://www.netl.doe.gov/technologies/oil-gas/publications/EP/CO₂_EOR_Primer.pdf](http://www.netl.doe.gov/technologies/oil-gas/publications/EP/CO2_EOR_Primer.pdf)

Charting the Growth of CO₂ EOR in the U.S.

By John R. Duda, U.S. Department of Energy, National Energy Technology Laboratory and Vello Kuuskraa, Michael Godec, and Tyler Van Leeuwen of Advanced Resources International, Inc. (A version of this article was first published in the Oil and Gas Journal.)

Enhanced oil recovery using injected carbon dioxide for miscible displacement of residual oil currently recovers about 250,000 b/d of incremental oil in the US. About 70% of this oil is produced in the Permian basin of West Texas and Eastern New Mexico, where CO₂ flooding is driven by a low-cost natural CO₂ source and reservoirs that are well suited for CO₂ flooding. More recently, the number of CO₂-EOR applications has increased in other areas where the same situation occurs, such as Mississippi-Louisiana and Wyoming-Colorado. Generally, a core group of projects provides the economic motivation for an initial pipeline, and the network of CO₂ distribution infrastructure grows as companies develop additional projects.

With the potential for large amounts of anthropogenic CO₂ being captured and made reliably available at relatively low cost as a result of possible climate-change regulations, there is a possibility of a similar scenario occurring in other US regions that have depleted oil reservoirs amenable to CO₂ EOR but not a ready, low-cost CO₂ source.

NETL and ARI employed a proprietary reservoir database to identify reservoirs in large oil fields where CO₂ EOR could produce large amounts of incremental oil. This analysis also quantified the volume of CO₂ that would remain sequestered in these reservoirs, a result yielding a rough measure of the dual benefits that a CO₂ storage-EOR paradigm could make possible. Some of these reservoirs could become anchor fields for new CO₂ collection and distribution infrastructure and the same infrastructure also could transport CO₂ for sequestration in deep saline formations, depleted gas fields, or other storage locations.

Identifying Regional Centers of CO₂-EOR Production

A prior study by the team assessed the role that "best practices" CO₂-EOR technologies could play in US oil recovery. It noted that CO₂ EOR could produce an additional 85 billion bbl of oil from the 400 billion bbl remaining unproduced in reservoirs across 11 US basins. The additional recovery would require:

- Introducing best practices technology where it is not yet applied.
- Lowering risks by conducting research, pilot tests, and field demonstrations in geologically challenging fields.
- Providing state production tax incentives, federal investment tax credits, and royalty relief.
- Establishing low-cost reliable CO₂ supplies.

In the current effort, NETL and ARI used the same proprietary database of large oil field data for identifying clusters of fields where CO₂ EOR could be viable and economical, and collectively, sufficiently large to serve as focal points for the development of new centers of CO₂-EOR production.

This study assessed more than 2,000 reservoirs and selected a subset of reservoirs, each individually containing more than 10 million bbl of original oil in place (OOIP) and located in fields with more than 50 million bbl of OOIP.

Of this subset, the assessment only evaluated reservoirs deeper than 3,000 ft and with oil gravity greater than 17.5° because these are the reservoir conditions for which CO₂ could become miscible with the in-place oil, facilitating enhanced recovery.

Based on the application of state-of-the-art best practices for CO₂ EOR, this analysis indicates that these large reservoirs potentially could produce more than 47 billion bbl of technically recoverable oil. While the analysis shows that the Permian Basin accounts for a large portion of this recoverable oil, there are billions of barrels of potential in California, the Gulf Coast, the Mid-Continent, and Rocky Mountain states as well (Figure and Table 1).

Much of this oil could become producible with the availability of reliable sources of reasonably priced CO₂ and the completion of precommercial operations performance analyses.

Of particular note is that 6 of the 11 basins assessed currently do not have commercial CO₂-EOR projects. Together these regions contain more than 20 billion bbl of technically recoverable oil—a major resource.

Moreover, several regions have scores of gigawatt-scale electric power generation facilities that emit large amounts of CO₂. The overlay of CO₂-EOR amenable oil reservoirs and power-generating plants presents an opportunity to expand conventional CO₂-EOR operations to noncore areas while simultaneously sequestering large quantities of CO₂.

New Study Looks at Flooding at Near-Miscible Pressures

The research team paid special attention to the potential for recovery from reservoirs where the flooding pressure would be slightly below or slightly above the minimum miscibility pressure (MMP).

Experimental data suggests that CO₂-EOR performance increases steadily as reservoir pressure approaches the MMP. As such, reservoirs likely to be flooded at pressures in the “grey area” of reservoir pressures immediately surrounding the MMP deserve extra attention. Immiscible floods in this range may perform similarly to miscible reservoirs if approaches to enhance miscibility can be successfully applied. As well, CO₂-EOR operations in reservoirs at pressures just greater than MMP may not achieve miscibility throughout the entire reservoir volume between injection and production wells, and this could reduce recovery potential.

The study showed that reservoirs flooded at pressures within 500 psi below the MMP contain 1.5 billion barrels of technically recoverable resource, mostly in California and Central Texas. Further analysis revealed that 1.3 billion barrels of this total are economically recoverable at an oil price of \$70/Bbl and a CO₂ cost of \$45 per metric ton (mt).

The results also showed that 4.1 billion barrels of technically recoverable oil are contained in reservoirs that could be CO₂ flooded at a pressure within a range of 500 psi above the MMP, of which 3.4 billion barrels are economically recoverable at \$70/Bbl and \$45/mt of CO₂. The regional distribution of resource is much broader in this case, including not only California and Central Texas, but also the Illinois Basin, Coastal Texas, the Mid-Continent, and Appalachia.

If approaches can be developed and applied to make CO₂ floods in this “grey area” behave like fully miscible floods, an additional 4.7 billion barrels of oil could become economically recoverable. Much of this oil is located in areas that would be “new ground” for CO₂ EOR developments.

What Impact Can New Technology Have on Recovery?

The team also analyzed the impact of applying next generation CO₂-EOR technologies which go beyond the current state-of-the-art. These technologies include:

- Increasing injected CO₂ to 1.5 hydrocarbon pore volume, considerably beyond what operators traditionally have used.
- Implementing innovative flood design and well placement options for contacting and producing less efficiently waterflood swept portions of the reservoir, for example, adding new horizontal and vertical wells and using gravity-stable designs in steeply dipping reservoirs.
- Increasing injected water and CO₂ viscosity in water-alternating-gas floods.
- Adding miscibility enhancers for lowering the pressure required for full miscibility.

The team modeled these alternatives on a reservoir-by-reservoir basis using a customized version of the stream-tube model CO₂-PROPHET, originally developed by NETL.

The results (Table 2) show that the technically recoverable oil with the application of next generation technologies is in excess of 30 billion bbl of incremental oil yielding a total recoverable resource of 77.6 when added to the 47 billion bbl recovery with state-of-the-art best practices.

New CO₂-EOR centers

A large portion of the 77.6 billion bbl, roughly a third, is in the Permian Basin. But even in the birthplace of CO₂ EOR, nearly half of the estimated technically recoverable resource will depend on new technologies.

Although a few companies already have begun to apply these practices in the Permian Basin, most have not. More interestingly, if companies can implement these new technologies hand-in-hand with new sources of CO₂, areas such as California, the Midcontinent, the Northern Plains, and Appalachia could become new CO₂-EOR hot spots.

Looking closely at just Southern California and the Midcontinent, we see that both areas could produce large amounts of incremental oil if a way can be found to capture, collect, and transport CO₂ (Table 3).

Southern California could economically (at \$70/bbl oil price and \$45/tonne CO₂ price) produce 8.6 billion bbl of oil and simultaneously store 1.9 billion tons of CO₂ with the development and application of next-generation technologies.

The Midcontinent under the same circumstances could produce and store about the same volumes. The total volume of CO₂ that reservoirs could store within all of the regions under a next generation technology scenario is 18 billion tons.

It is also important to remember that estimates contained in Table 2 are based on an analysis of the largest reservoirs in the largest fields. Once a CO₂ delivery infrastructure is developed around anchor projects, smaller reservoirs in smaller fields may also become economic targets for CO₂ EOR.

A related analysis (unpublished) evaluated the potential for applying CO₂ EOR to residual oil zones beneath the original oil-water contact in large reservoirs. In some areas, large volumes of incremental oil could be produced and equally large volumes of CO₂ could be stored in these previously untapped segments of the nation's large oil reservoirs.

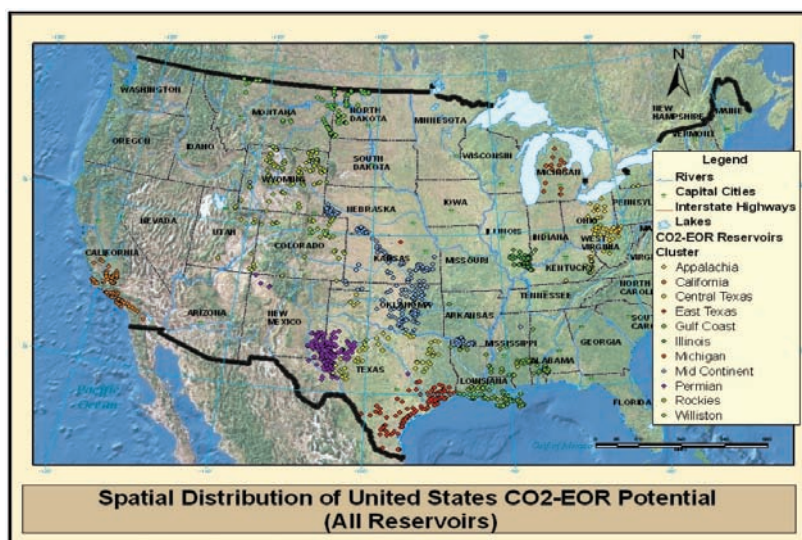


Figure 1. Spatial Distribution of Large, CO₂-EOR Amenable Reservoirs.

An estimate is that these deep, water saturated sections of mature fields could store more than 54 billion tons of CO₂.

Energy security, environmental goals

This analysis highlights the need for a series of conventional CO₂-EOR pilot tests in noncore areas and enhanced research focused on next generation CO₂-EOR technologies, both of which will help catalyze a nationwide CO₂ EOR and carbon storage industry.

These R&D activities must be coordinated to advance the energy security, environmental preservation, and economic goals of our nation by reducing oil imports on a barrel-for-barrel basis, capturing and injecting CO₂ underground, and creating well-paying jobs in rural areas.

CO₂ EOR can provide an economic incentive that reduces the risk of carbon capture and storage and could help jump start development of infrastructure that will ultimately enable large portions of the nation's CO₂ emissions to be sequestered in more geologic storehouses.

NETL has implemented an R&D program to help develop and demonstrate these new technologies in new areas. For more information on this study or the research that is under way at NETL, contact John R. Duda, Director, NETL Strategic Center for Natural Gas and Oil (john.duda@netl.doe.gov).

Table 1. Technically Recoverable Resource Amenable to CO₂ EOR in Large U.S. Reservoirs

| Technically Recoverable Resource (MMBbls) | | | | | | |
|--|-----------------------|--------------|--------------|---------------------|---------------|---------------|
| Cluster | Immiscible Reservoirs | | | Miscible Reservoirs | | |
| | Near | Fully | Total | Near | Fully | Total |
| Appalachia | 0 | 137 | 137 | 197 | 900 | 1,097 |
| California | 768 | 515 | 1,284 | 859 | 3,529 | 4,388 |
| Central Texas | 595 | 35 | 630 | 237 | 5,624 | 5,861 |
| Coastal Texas | 19 | 134 | 152 | 392 | 3,845 | 4,237 |
| Gulf Coast | 1 | 43 | 45 | 135 | 3,963 | 4,098 |
| Illinois | 0 | 0 | 0 | 348 | 247 | 594 |
| Michigan | 0 | 0 | 0 | 9 | 206 | 215 |
| Mid Continent | 0 | 5 | 5 | 1,263 | 5,096 | 6,359 |
| Permian | 0 | 111 | 111 | 418 | 13,010 | 13,428 |
| Rockies | 103 | 189 | 291 | 143 | 2,482 | 2,625 |
| Williston | 0 | 12 | 12 | 81 | 1,746 | 1,827 |
| Total | 1,486 | 1,182 | 2,668 | 4,081 | 40,647 | 44,729 |
| Average Recovery Efficiency (%OOIP) | 11 | 13% | 12% | 16% | 22% | 22% |

Table 2. Additional Technically Recoverable Resource Amenable to CO₂ EOR in Large U.S. Reservoirs Resulting from “Next Generation” Technologies

| Cluster | Best Practice | | Next Generation | | Delta Technically Recoverable |
|---------------------|-----------------|------------------|-----------------|------------------------|-------------------------------|
| | Active Projects | Practices (MMBO) | Active Projects | Next Generation (MMBO) | |
| Permian | 58 | 13,539 | - | 22,717 | 9,179 |
| Central Texas | 0 | 6,491 | - | 9,940 | 3,449 |
| Mid Continent | 8 | 6,365 | - | 10,165 | 3,801 |
| California | 0 | 5,672 | - | 8,966 | 3,294 |
| East Texas | 0 | 4,389 | - | 7,015 | 2,626 |
| Gulf Coast (Non TX) | 15 | 4,142 | - | 5,878 | 1,735 |
| Rockies | 16 | 2,916 | - | 5,565 | 2,649 |
| Williston | 0 | 1,839 | - | 2,799 | 960 |
| Appalachia | 0 | 1,236 | - | 1,944 | 708 |
| Illinois | 0 | 594 | - | 2,376 | 1,782 |
| Michigan | 8 | 215 | - | 276 | 61 |
| Grand Total | 105 | 47,398 | | 77,642 | 30,244 |

Table 3. Economically Recoverable Resource Amenable to CO₂ EOR in Large California and Mid-Continent Reservoirs and CO₂ Stored After EOR.

| | Recoverable Oil (Billion Barrels) | | CO ₂ Stored (Gt) |
|------------------------|-----------------------------------|----------|-----------------------------|
| | Technical | Economic | |
| Mid-Continent | | | |
| <i>Best Practices</i> | 6.4 | 5.7 | 1.6 |
| <i>Next Generation</i> | 10.1 | 8.9 | 2.1 |
| California | | | |
| <i>Best Practices</i> | 5.6 | 5.4 | 1.4 |
| <i>Next Generation</i> | 8.9 | 8.6 | 1.9 |



NETL Facilitates Technical Exchange with CNPC Delegation

In early April, a group of 11 scientists, engineers and senior managers from China National Petroleum Corporation (CNPC), led by Dr. Jia Chengzao, Chairman of the Chinese Petroleum Society of CNPC and former Vice President of PetroChina, met with DOE personnel, including John R. Duda, Director of the Strategic Center for Natural Gas and Oil (SCNGO) at the National Energy Technology Laboratory (NETL), to further collaborative efforts in R&D in the area of fossil energy. The meeting, one of an ongoing series, furthered the objectives of a Memorandum of Understanding, signed by CNPC and NETL, to collaborate on technology for gas hydrates development, CO₂-EOR, protection of environmental resources, natural gas shale development and high-temperature, high-pressure drilling.

The meeting focused specifically on shale gas development and was highlighted by the CNPC delegation's visit to Devon Energy's Cana-Woodford shale operations. The delegation reviewed technology used in those operations that can be used to develop the immense shale gas potential of China in an environmentally responsible manner. NETL was instrumental in facilitating the visit with Devon Energy.

The meetings with NETL and Devon Energy contribute directly to the U.S.-China Shale Gas Resource Initiative signed last November by President Obama and Chinese President Hu Jintao. The initiative calls for reduction of greenhouse gas emissions, increased energy security and creation of commercial opportunities for U.S. companies through shale gas resource assessment, technical cooperation and the promotion of investment in China through the U.S.-China Oil and Gas Industry Forum. Furthermore, the initiative calls for workshops and study tours, such as the Devon visit, focused on attracting shale gas development to China.

In addition to furthering the objectives of both the CNPC – NETL MOU and the U.S.- China Shale Gas Initiative, the technical exchange and tour of field

operations also directly supports the objectives of the bilateral U.S. – China Fossil Energy Protocol, specifically Annex III, Oil and Gas. This Protocol is intended to promote scientific and technological cooperation between the United States and China in the field of fossil energy, particularly activities related to research, development, demonstration, and deployment. The Protocol also seeks to provide opportunities for U.S. industry and power developers in China to expand the environmentally responsible and commercially beneficial supply of energy in the region.



One of two groups stop for a photo in front of a 15,000 psi tree in the Cana Field after completion of a 10-stage hydraulic fracturing treatment in the Woodford Shale. Dr. Jia Chengzao is 4th from left, followed by John R. Duda of SCNGO and Vince White of Devon.



Upcoming Meetings and Presentations



Seventeenth SPE Improved Oil Recovery Symposium

24-28 April

Renaissance Hotel, Tulsa, OK

Visit NETL booth #27

For More Information: www.speior.org/

Offshore Technology Conference, NETL Press Briefing

9:00, May 4

Press Room, Reliant Center, Houston, TX

Visit NETL/DOE booth #1652

For More Information: <http://www.otcnet.org/2010/>

24th Annual Conference on Fossil Energy Materials

May 25-27, 2010

Omni William Penn Hotel, Pittsburgh, PA

For More Information: Karen.Lockhart@pr.netl.doe.gov