**PDHonline Course C794 (3 PDH)**

# DOE Enhanced Oil Recovery Program


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# DOE's Enhanced Oil Recovery Program
# An Archive of Important Results

April 2008

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**April 2008**

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# Executive Summary

Primary and secondary oil production recovers on average about 40% of the original oil in place (OOIP) in oil reservoirs. The remaining oil (currently about 400 billion barrels in the U.S.) is a target for enhanced oil recovery (EOR) methods. The Department of Energy's (DOE) research related to EOR has focused on developing advanced technology, providing a greater understanding of EOR, and transferring technology to aid industry in recovering a greater portion of this important domestic energy resource.

The DOE's various R&D efforts related to EOR, termed herein the "EOR Program," were initiated during the 1973-74 energy crisis and formally established in 1978. Initially driven by the Arab oil embargo, the objective of the program was to reduce dependence on foreign oil by increasing the ability of the domestic oil industry to recover the significant fraction of oil left behind after primary and secondary production in U.S. oil fields. The program funded research to improve the effectiveness and reduce the costs of all EOR methods and also to improve industry's ability to predict reservoir response and project performance using numerical simulation and modeling.

From FY1978 through FY2007 a total of 322 research development and demonstration (RD&D) projects were conducted. The Program provided publicly available EOR process data at a time when only major oil companies had access to the information and provided a mechanism for the collaboration of academia, government research organizations and industry. Some of the more important contributions of the Program included:

- Improved understanding of $CO_2$ EOR early in the life of the process. The basic fluid properties of $CO_2$ that were measured under the Program provided the foundation for subsequent improvements in process design and field implementation. Foams, gels, and thickeners were developed that increased effectiveness by improving sweep efficiency. The applicability of $CO_2$ EOR to a variety of oil reservoirs was successfully demonstrated.
- Advancement in the efficiency, economics, and range of applicability of steamflooding was achieved through the development of methods for reducing wellbore heat losses, improvement of cogeneration technologies (use of produced gas to make steam), and the design of foams and gels for improved sweep efficiency.
- Major contributions to the development of polymer gel systems that are used commercially today to improve sweep efficiency. Program research helped to increase the stability of polymers and extended the range of reservoir conditions where polymers could be used.
- Demonstration of one of the very first efforts to apply microbial EOR. Optimum bacterial strains were cultivated to stimulate production and improve sweep efficiency. The technology is now used commercially throughout the world.
- Early efforts to widen the application of reservoir simulation by both large and small operators. The Program developed simulators to model fluid flow in heterogeneous reservoirs, resulting in the creation and dissemination of publicly available simulators such as BOAST (black oil model), UTCHEM (chemical flooding), MASTER (gas injection), and $CO_2$ Prophet ($CO_2$ injection) to a broad range of users. Screening models were developed to ascertain the applicability of various EOR processes to specific reservoirs, helping operators recognize opportunities to apply EOR in mature fields.

EOR methods are generally categorized into four main types: *chemical methods* (which typically employ surfactants or other chemicals to reduce the physical forces holding the oil within the pores of the rock or to increase areas swept by any other chemical or gas); *gas flooding methods* (which usually employ carbon dioxide ($CO_2$) or enriched natural gas to miscibly mix with the oil and sweep it from the pore spaces where it is trapped); *microbial enhanced oil recovery* or MEOR (where the action of either resident or injected microbes is enhanced to increase incremental oil production by altering surface tension *in situ* or creating *in situ* plugging of "watered out" channels increasing sweep efficiency); and *thermal methods* (which employ heat to reduce the viscosity of the oil and make it easier to push from the rock with injected water. Thermal methods include the more common steam injection (steamflooding) and the less commonly applied *in situ* combustion, where a portion of the oil is burned within the reservoir to produce heat. Methods to enhance the performance of *secondary recovery* operations (waterfloods) by using polymer gels designed to improve the ability of injected water to uniformly sweep the oil from the rock are sometimes included in the portfolio of EOR methods under the term *improved waterflooding*.

Today, EOR is responsible for a significant amount of domestic oil production. In 2006, 12.7% of the total U.S. crude oil production was recovered using EOR methods. Steamflooding (5.9%) and $CO_2$ injection (4.5%) are by far the most commonly used methods (Moritis, 2006). Total EOR production has been on the increase; from 604,786 bopd in 1986 to 649,322 bopd in 2006. $CO_2$-enhanced production can be expected to rise with new sources of $CO_2$ becoming available from power plants and other industries looking to reduce carbon emissions.

In general, the Program targeted EOR processes that were at or near commercialization (with the exception of MEOR) with the major objective being the extension of EOR process applicability to a wider range of reservoir conditions. Twenty-nine percent of these were chemical flooding projects, 24% were thermal recovery projects, 22% were gas injection projects, 16% were MEOR projects and 9% were addressed towards simulation and modeling. Of the roughly $225 million in DOE funding for EOR research over this time period (exclusive of field demonstration projects), 27% went to chemical flooding, 21% to thermal recovery, 29% to gas injection, 11% to MEOR and 9% to simulation.

The entire EOR research effort conducted by the DOE can be segmented into a number of individual initiatives over the three-decades spanning 1978 to 2007. These include: a high-risk cost-shared EOR field pilot demonstration program in the mid-to-late 1970s, basic R&D during the early 1980s, a focused effort on technologies to decrease operator risk and reduce well abandonment during the mid-1980s to early-1990s, and another field demonstration program focused on technologies directed at particular classes of reservoirs based on their geologic characteristics during the 1990s. The benefits that accrued from these efforts have been significant.

The National Research Council (NRC) in 2000 conducted reviews of DOE's RD&D programs for the period 1978 to 2000, and produced a report titled "Energy Research at DOE: Was It Worth It? Energy Efficiency and Fossil Energy Research 1978 to 2000." Based on information provided by the DOE, the NRC determined that the DOE EOR program spent $177 million (1999 dollars, exclusive of the field demonstration projects) and attracted $47 million of industry cost share. In return for this investment, the report states that as of 2000 the program had returned $625 million (1999 dollars) in cost savings to oil producers, with a benefit/cost ratio of 3.5 to 1. If incremental federal and state revenues resulting from the incremental production are included, the total increases to $700 million.

The NRC report also looked at the costs and benefits associated with the field demonstration projects from 1978 to 1999, where DOE expended $259 million (1999 dollars) and attracted industry cost share of $368 million. Approximately one-half of the funding was spent on an early high-risk cost-shared EOR field pilot demonstration program in the mid-to-late 1970s and the other half on demos directed at particular classes of reservoirs based on their geologic characteristics during the 1990s; the Reservoir Class Program. The 2000 NRC report assessed that the field demonstration portion of the EOR program would result in 1.3 billion barrels of incremental oil production and 1.7 Tcf of incremental gas production between 1996 and 2005, and would provide net revenues to industry of $4,462 million (1999 dollars). This yielded a benefit to cost ratio of 17.2 to l. DOE calculated an additional $758 million (1999 dollars) from increased federal royalties and additional state severance taxes due to displacement of imports.

Given the facts that these assessments were conducted in 2000 on benefits accrued to date, and that the price of oil has risen significantly over the past seven years, the current total Program benefits can only be assumed to be higher still.

This document presents the key contributions of the DOE EOR Program for each of six process categories: gas injection, thermal methods, chemical flooding, MEOR, improved waterflooding and reservoir simulation. For each category, selected project summaries are used to illustrate the contributions of the Program to the progress of commercial EOR operations.

Appendix A provides summary details on 16 of the 23 cost-shared field demonstration projects carried out during the mid-to-late 1970s. Post-project evaluation reports for these projects are included on the archive CD. Appendix A also provides summary details on 23 of the Reservoir Class Field Demonstration Program projects that dealt with EOR.

Appendix B provides summary details on another 56 individual projects selected from the total of 322 as particularly significant in terms of their contribution to the progress of EOR nationwide.

The DVD on which this report is found includes an Excel spreadsheet holding the title, author publication date and contract details for 1511 documents related to the EOR Program. Of these titles, more than 850 are linked to scanned copies of the documents included on the DVD.  As additional documents are recovered from files and archives, they will be added to subsequent editions of the DVD.

# DOE's Enhanced Oil Recovery Program

## An Archive of Important Results

## Introduction

Primary oil production recovers from 10% to 25% of the original oil in place (OOIP) in a reservoir; leaving 75% to 90% of the oil in the ground (Lake, *et al.*, 1992). Secondary recovery (water or gas injection) can recover another 15% of the oil; leaving 60% or more as a target for enhanced oil recovery (EOR) methods. This target is estimated to total 210 billion barrels in domestic oil reservoirs (ARI, 2006). The oil remaining after primary and secondary recovery is difficult to produce because it is located in regions of the reservoir that are hard to access and is bound tightly into the pores of the rock.

EOR methods are generally categorized into four main types: *chemical methods* (which generally employ surfactants or surfactant-producing chemicals to reduce the physical forces holding the oil within the pores of the rock); *gas flooding methods* (which generally employ $CO_2$ or enriched natural gas to miscibly mix with the oil and sweep it from the pore spaces where it is trapped); *microbial enhanced oil recovery* or MEOR (where the action of either resident or injected microbes is enhanced to produce natural surfactants *in situ* to help remove the oil from the rock); and *thermal methods* (which employ heat to reduce the viscosity of the oil and make it easier to push from the rock with injected water. Thermal methods include the more common steam injection (steamflooding) and the less commonly applied in situ combustion, where a portion of the oil is burned within the reservoir to produce heat. Methods to enhance the performance of secondary recovery operations (waterfloods) by using polymer gels designed to improve the ability of injected water to uniformly sweep the oil from the rock are sometimes included in the portfolio of EOR methods under the term *improved waterflooding*.

Incremental production resulting from EOR methods comprises a significant portion of total U.S. crude oil production. In 2006, EOR production in the U.S. was 649,322 barrels of oil per day (bopd) and accounted for 12.7% of total U.S. crude oil production (Moritis, 2006). Thermal methods (primarily steamflooding) accounted for 5.9% of U.S. total production while miscible $CO_2$ injection accounted for 4.5%. While thermal production has declined from 479,669 bopd in 1986 to 301,704 bopd in 2006, production from $CO_2$ injection has risen nearly ten-fold from 28,440 bopd in 1986 to 234,420 bopd in 2006. Total EOR production has increased from 604,786 bopd in 1986 to 649,322 in 2006. Incremental oil production from $CO_2$ floods can be expected to rise as new sources of $CO_2$ become available from power plants and other industries looking to reduce carbon emissions.

The goal of the United States Department of Energy (DOE) Fossil Energy oil and gas research program has been to reduce dependency on foreign oil by developing technologies to keep existing fields productive, increase domestic reserves, and locate new resources, all while minimizing the impact on the environment.

The Enhanced Oil Recovery (EOR) Program supports those goals by developing technologies to recover the significant portion of the original oil in place that is not produced by primary (pressure depletion) or secondary (water or gas injection) recovery methods. The research in the EOR Program has been designed to involve academia, government research organizations, and industry partners in collaborative efforts focused on improving the efficiency and lower the costs of EOR processes. The topics that have been the target of research have included: gas injection, thermal recovery, chemical flooding, microbial enhanced oil recovery (MEOR), profile modification, and simulation/model development.

While EOR projects typically do not have the exploration costs and risks associated with finding new oil, they do require significant capital investment risks and can have much higher operating costs than conventional production. Much of the R&D carried out by the DOE EOR Program has focused on developing technologies that can reduce these risks and lower these costs.

## EOR Basics

A few basic concepts and terms are discussed here so that the less technical reader can understand the problems associated with EOR processes and thereby appreciate the research results that address these problems.

Residual oil, the oil left after primary and secondary recovery, is held in the pores of the reservoir rock by capillary pressure or viscosity (a fluid's resistance to flow). The fluids injected into a reservoir during EOR operations are all designed in some way to increase the *mobility* of the oil.

The four main EOR processes are gas injection (either miscible or immiscible), thermal recovery, chemical flooding, and microbial EOR. Each of these processes involves injecting a fluid into the reservoir (via injection wells) and sweeping a portion of the remaining oil out of the rock through production wells. Gas flooding methods, generally employ $CO_2$ or enriched natural gas because under certain conditions these fluids are miscible with the oil. Miscibility means that the interface between injectant and the oil disappears allowing the injected fluid to more efficiently move the oil out of the pores. Other gases that are immiscible with oil, such as nitrogen or flue gas (waste gas from a combustion process that is a mix of $CO_2$ and other gases) are sometimes used in EOR processes to maintain reservoir pressure.

Thermal methods reduce the viscosity of light or heavy oils, most commonly by injecting steam (steamflooding) or by burning part of the oil in the reservoir (*in situ* combustion) to produce heat. When the viscosity of the oil is lowered, the oil is more mobile and more easily pushed from the reservoir by the condensed steam (hot water) or hot water and expanding gases of an *in situ* combustion flood. In some cases steam is injected into a well for a period of time, after which the well is shut in for a period before being produced; what is termed *huff-and-puff* or cyclical steam injection.

Chemical methods involved the injection of a volume of surfactant to lower the surface tension between the water and oil, allowing the oil to be more efficient swept from the rock, similar to the action involved in using soap to clean oil from a surface. Alkaline chemicals can be injected to form natural surfactants when they come in contact with components of crude oil. Similarly, in the case of microbial enhanced oil recovery the action of microbes on the crude oil produces by-products that improve the ability of the following injected water to move the oil from the rock.

In an ideal EOR process, the injected fluid moves as a unified vertical front that sweeps all the residual oil towards a production well. In such a case the process would be said to exhibit very good *sweep efficiency*. It is more likely, however, for problems to occur; both vertically and horizontally. For example, the injected fluid can move along the top of the reservoir because of density differences between the injected fluid and oil (called gravity override); a problem that can be exacerbated when the upper layers of the reservoir exhibit higher permeability than the lower layers. Another problem can occur when the injected fluid takes the path of least resistance in the horizontal plane and follows a higher permeability zone or the path where the occupying fluid has a lower viscosity. This results in finger-shaped irregularities at the leading edge of the displacing fluid which can then move out ahead of the main body of injectant. With both gravity override and fingering, a portion of the injected fluid breaks through to the production well, bypassing the oil not contacted by the injected fluids. Once breakthrough occurs, the injected fluid continues to flow through the established pathways and does not contact the rest of the reservoir. The less volume of reservoir contacted, the less efficient the EOR process in recovering residual oil.

In general, the research reviewed in this report focuses on solutions to these basic limitations of the EOR process and is concerned with finding ways to increase the mobility of the oil, improve the sweep efficiency (both vertical and horizontal) or reduce the costs of the various processes.

# Program History

The energy crisis launched by the 1973-74 Arab oil embargo set the stage for enhanced oil recovery research. Reducing the dependence on foreign oil by increasing domestic production became a high priority for US policymakers. In 1975 the Bureau of Mines Center in Bartlesville, Oklahoma (originally established in 1918) began operating under the Energy Research and Development Agency (ERDA) as the Bartlesville Energy Research Center, and later was renamed the Bartlesville Energy Technology Center (BETC) within the newly formed Department of Energy. In 1976, BETC was designated as the lead center for EOR research on recovery from light gravity oil reservoirs.

In an effort to stimulate the wider application of emerging EOR technologies, the DOE launched a high-risk cost-shared EOR technology field demonstration program. The program was initiated in 1974 and 23 projects with oil companies were funded. Oil company participants included Gulf, Exxon, Conoco, and Shell. Pilot projects employing $CO_2$ injection, polymer-enhanced waterflooding, alkaline waterflooding, surfactant flooding, micellar-polymer flooding and other processes were demonstrated (See Appendix A for descriptions of the key projects).

While many of the demonstrations were technical successes only a few were both technical and economic successes (steam floods). Still, the demonstrations were extremely valuable in identifying problems associated with various EOR methods and, as such, they help guide future EOR R&D. The most significant knowledge that resulted from these early field demonstrations was revelation that the geological and engineering parameters of individual fields were insufficiently known and that most reservoirs were much more geologically complex than originally thought. The critical importance of completing a thorough reservoir characterization before designing and implementing an EOR project was underscored by project results.

By 1978, the EOR program was redirected from funding field demonstrations to funding basic and applied research. Research in thermal recovery methods, gas injection, and chemical flooding were initiated with microbial enhanced oil recovery (MEOR) research beginning in 1980 and numerical modeling and simulator development added in 1982 (Figure 1).

In 1983, BETC privatized its research facility, establishing the National Institute for Petroleum and Energy Research (NIPER) a 200-person laboratory operated by IIT Research Institute, under the direction of DOE's Bartlesville Project Office (BPO). Cutting-edge research in EOR processes and reservoir characterization methods was conducted. Rock and fluid property and saturation measurement methods were developed including laboratory facilities to measure three-phase relative permeability. BOAST, a black oil simulator, was developed and for a time was the only non-proprietary reservoir simulator freely available to the public. Nuclear magnetic resonance (NMR) and computed tomography (CT) scanning were used to image fluid flow through porous media at a time when the only other work being conducted with these tools was within company labs. A bench-scale high-temperature steam flood model was built to understand the mechanisms of thermal recovery.

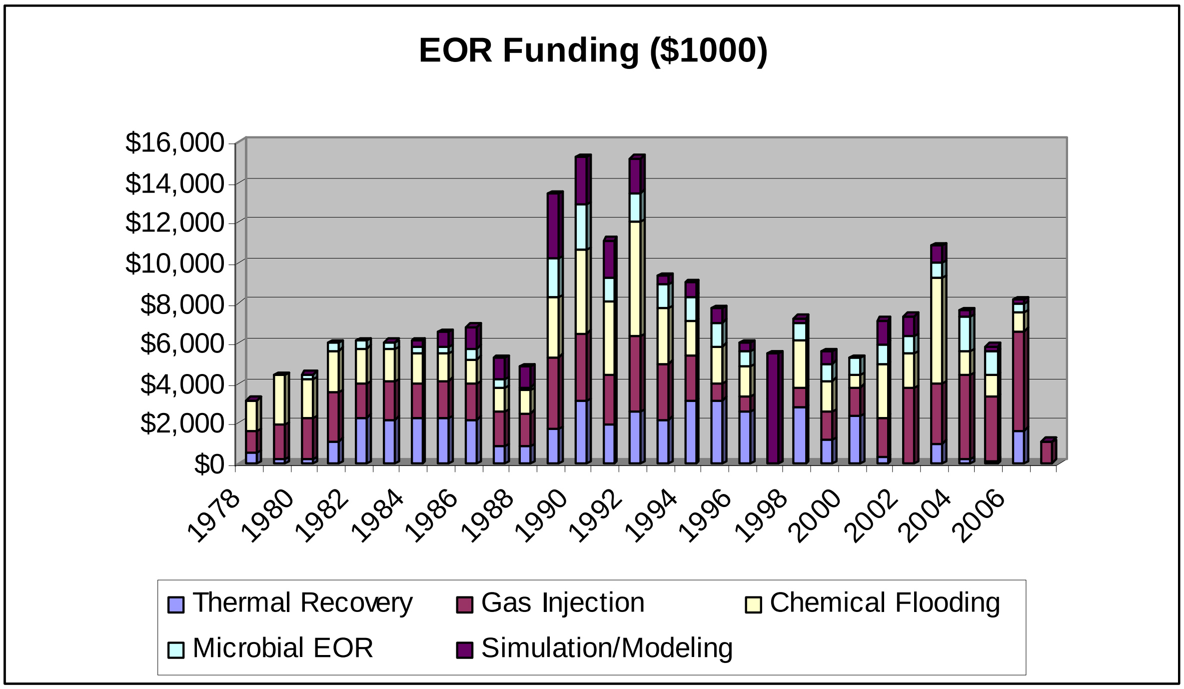


**Figure 1. DOE EOR research funding from FY1978 through FY 2007**
***(does not include field demonstration projects)***

In response to the oil price collapse of 1986, funding for the EOR program was reduced in fiscal years 1988 and 1989 (Figure 1). At about the same time, large integrated oil companies began restructuring, downsizing, and reducing their R&D budgets. The majors' focus shifted to the search for larger fields in the offshore U.S. and in foreign countries. The shift in assets meant that the independent oil companies began to assume the position of major domestic oil producers.

The DOE saw a role in supporting the development of promising technologies considered too risky by the independent operators. BPO's oil research program turned its emphasis to the application of existing and developing technologies to decrease operator risk, improve near-term production, reduce the rate of well abandonment, and thus maintain access to the oil resources remaining in maturing U.S. domestic reservoirs.

In 1993, BDM-Oklahoma took over the management of NIPER. The EOR research portfolio remained focused on basic and near-term research and the development of technologies that could be implemented by independent oil companies. Funding increased substantially during 1989-1992.

EOR research at NIPER at this time resulted in a number of significant accomplishments:

- A new up-scaling technique for reservoir simulation that reduced the number of grid blocks required for simulation,
- Validation of simulation results using computed X-ray tomography and data from mini-permeameter and tracer tests,
- New experimental apparatus and techniques including the low-energy x-ray technique for measuring *in situ* fluid saturations and flow dynamics in reservoir rocks,
- An increase in the resolution of NMR microscopy from 45 to 11 microns,
- A novel profile modification method using a surfactant-alcohol mixture that when field tested reduced production declines by more than 40%,
- An alkaline-surfactant-polymer (ASP) field test that resulted in a four-fold increase in production,
- An *in situ* combustion process handbook detailing best practices for designing, engineering, implementing, and operating a commercial project, and
- A screening methodology for assessing 190 Gulf of Mexico heavy oil reservoirs and subsequent in-depth simulation studies of steam injection that showed that many Gulf Coast reservoirs could respond favorably to steam injection.

In the early 1990s the National Energy Strategy called for increased domestic oil recovery efficiency and recommended efforts to counteract the trend of field abandonment by identifying high potential fields and preserving access to them through targeted technology transfer of the best available processes.

The Reservoir Class Field Demonstration (Class) program was developed as a cost-shared program where DOE co-funded projects with oil and service companies. Project cost sharing through industry-government partnerships was used to leverage federal funds, ensure that research targeted high-value problems, and involve industry in the transfer of technologies to the marketplace. The program was initiated in 1991 with a near- and mid-term focus on reservoir characterization and field development, and the goals of extending the economic production of domestic fields and slowing the rate of well abandonment and industry infrastructure.

The Class Program consisted of 39 field projects concentrating on those domestic reservoirs that contained the largest volume of residual oil resources. A total of 23 of the Class Program field demonstration projects applied EOR and enhanced waterflooding processes that produced a significant number of major successes and yielded excellent returns in terms of incremental oil production, improved technologies suitable for broad application, and economic benefits. For example, one project in Utah demonstrated waterflooding to a paraffinic oil reservoir that when applied by other operators in the region resulted in the incremental production of 25 million barrels of oil and 70 billion cubic feet of gas. In another example, a shut-in heavy oil lease in the Midway Sunset field in California was revived through a steam injection pilot demonstration and ultimately produced 4.4 million barrels of oil. The benefits generated by these two projects alone provided enough tax and royalty revenue to offset the R&D investment of the entire Class program (See Appendix A for Class EOR project summaries).

In 1998 amid the focus on "small government," DOE funding for the NIPER laboratory was terminated and the Bartlesville Project Office moved to Tulsa, OK. The office was renamed the National Petroleum Technology Office (NPTO) and in 2004 became part of the National Energy Technology Laboratory (NETL).

During the entire 1978 to 2007 time period the DOE provided total R&D funding of about $224 million for the EOR Program (exclusive of the early field demonstration projects and the Class Program demonstration projects) and funded 322 research projects, including 71 gas injection projects, 77 thermal recovery projects, 94 chemical flooding projects, 51 microbial EOR projects and 29 simulation projects.

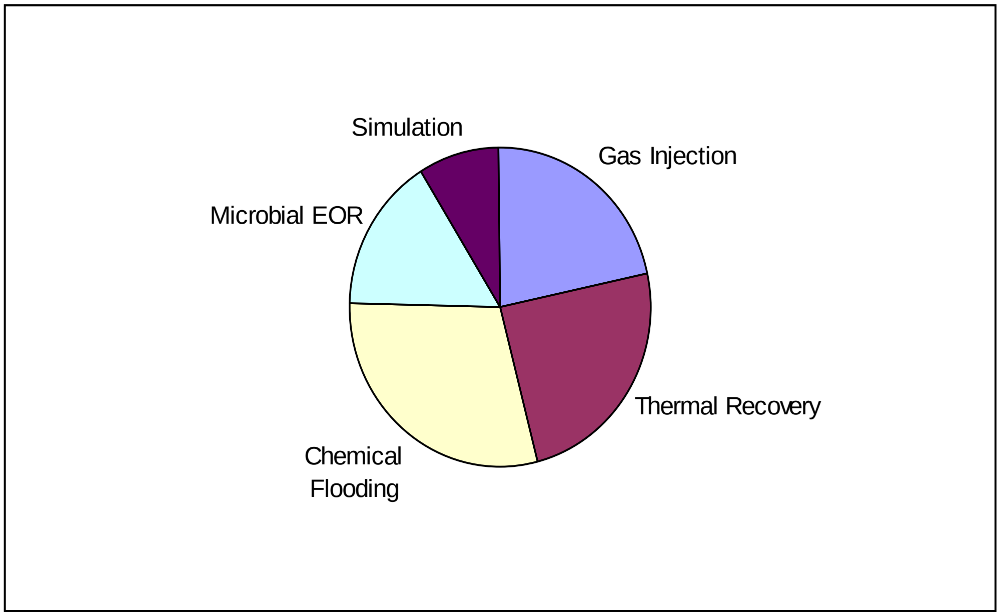


**Figure 2. Distribution of projects by EOR process.**

Most of the research targeted EOR processes that were at or near commercialization. The work in the program focused on technologies that could overcome the technical constraints that limited the application of the process. The ultimate goal was to increase the applicability of the processes and thereby increase the amount of oil that can be recovered within the U.S.

The National Research Council (NRC) in 2000 conducted reviews of DOE's RD&D programs for the period 1978 to 2000, and produced a report titled "Energy Research at DOE: Was It Worth It? Energy Efficiency and Fossil Energy Research 1978 to 2000." Based on information provided by the DOE, the NRC determined that the DOE EOR program spent $177 million (1999 dollars, exclusive of the field demonstration projects) and attracted $47 million of industry cost share. In return for this investment, the report states that as of 2000 the program had returned $625 million (1999 dollars) in cost savings to oil producers, with a benefit/cost ratio of 3.5 to 1. If incremental federal and state revenues resulting from the incremental production are included, the total increases to $700 million.

The NRC report also looked at the costs and benefits associated with the field demonstration projects from 1978 to 1999, where DOE expended $259 million (1999 dollars) and attracted industry cost share of $368 million. Approximately one-half of the funding was spent on an early high-risk cost-shared EOR field pilot demonstration program in the mid-to-late 1970s and the other half on demos directed at particular classes of reservoirs based on their geologic characteristics during the 1990s; the Reservoir Class Program. The 2000 NRC report assessed that the field demonstration portion of the EOR program would result in 1,291 million barrels of incremental oil production and 1,736 Bcf of incremental gas production between 1996 and 2005, and would provide net revenues to industry of $4,462 million (1999 dollars). This yielded a benefit to cost ratio of 17.2 to l. DOE calculated and additional $758 million (1999 dollars) from increased federal royalties and additional state severance taxes due to displacement of imports.

# Key Contributions

The EOR Program improved industry understanding of fundamental EOR processes, provided publicly available EOR process data when only major oil companies had access to the information, and openly demonstrated EOR technologies an effort to increase their commercial application. Some of the key contributions of the program are listed below, by process type.

**$CO_2$ Injection**

- In the 1970s through the early 1980s, DOE funded research on the basic fluid properties of $CO_2$ with respect to pressure, temperature, and oil composition. The effort provided a foundation to develop better $CO_2$ injection designs and processes and provided some of the first publicly available data on $CO_2$ properties. This work prioritized critical $CO_2$ properties and provided industry with a guide for further research.
- In the last decade, DOE has funded the only public research to evaluate, test, and design foams, gels, and thickeners for improving sweep efficiency in $CO_2$ injection.
- The EOR program has demonstrated the effectiveness of $CO_2$ injection for light and medium weight oils. $CO_2$ recovery of heavier weight oils where a miscibility condition is not developed has also been successfully demonstrated. This work led to a number of successful $CO_2$ projects in the U.S.

**Thermal Recovery**

- The DOE research program focused on the efficiency, economics, and range of applicability of steamflooding. Research evaluated methods to improve the performance of steam injection projects, including (1) methods for reducing wellbore heat losses, (2) use of the gas produced with the oil to make steam (cogeneration) thereby reducing costs, and (3) use of foams and gels for improving sweep efficiency.

**Chemical Flooding**

- A combination of experimental and theoretical studies of miceller-polymer processes and wettability led to the development and demonstration of an alkaline-surfactant-polymer (ASP) flood. The ASP method developed was a low cost and effective surfactant method that is in commercial use today throughout the world.

**Injection Profile Improvement for EOR and Waterfloods**

- DOE-funded R&D played a major role in the development of polymer gel systems that are used commercially today for improving the sweep efficiency of injected fluids and reducing water protection. Research focused on ways to improve the stability of polymers, extend the range of reservoir conditions where the polymers could be used, and develop new applications for polymers.

- DOE-funded R&D developed cross-linked polymer gel systems to control injection profiles and reduce water production. The research led to the development of commercial products that are widely used by industry today.

**Microbial EOR**

- The EOR program funded one of the first efforts to apply microbial technologies to subsurface rocks to stimulate production and improve sweep efficiency; a process now used commercially to stimulate producing wells. DOE-funded work continues to lead in the development of microbial EOR processes. The environmental industry has adapted much of the knowledge gained from the MEOR program for the bioremediation of petroleum-based substances.

**Simulation**

- DOE-funded researchers were at the forefront of reservoir simulation technology in the early 1980s and led numerous research projects focused on modeling flow behavior in heterogeneous reservoirs. Major developments include the development of BOAST (black oil simulator), UTCHEM (chemical simulator), MASTER (gas simulator), $CO_2$ Prophet, and multiple EOR screening models. BOAST is still widely used by industry. In 2000, 230 copies of the software were downloaded monthly on average from the NETL website. The program screening model $CO_2$ Prophet is still widely used as a first pass screening tool for $CO_2$ injection and water flooding reservoir assessments.
- From around 1978 to 1986, large companies spent millions of dollars on consulting and in-house simulation projects. Without DOE's investment in free-to-the-public models, the smaller-scale simulators used by independent oil and gas operators would not have been as quickly developed and widely used as they are today.

The following sections provide a more detailed look at selected projects grouped under their respective EOR process category. In each case a description of the process and it's unique challenges is followed by a general summary of the related work done under the EOR Program and a number of selected project summaries that highlight the more important contributions made by the Program.

## *Gas Injection*

In its early applications, gas injection involved the injection of natural gas (methane) enriched with ethane, propane or butane to increase it's miscibility with the oil in the reservoir. However, as natural gas became a more valuable product a replacement was sought. Carbon dioxide, under certain conditions of temperature and pressure, is miscible with crude oil. The relatively close proximity of natural sources of $CO_2$ in Utah, Colorado and New Mexico together with large reservoirs amenable to $CO_2$ flooding in the Permian Basin of West Texas, led to the construction of a pipeline system to deliver the gas and the initiation of a number of large gas injection projects during the 1970s and 1980s.

Miscible $CO_2$ is the fastest growing EOR process. In 1986 $CO_2$ production was 28,440 bopd whereas in 2006, $CO_2$ production was 234,420 bopd or 4.5% total U.S. production (Moritis, 2006). A nearby source or pipeline infrastructure is required to transport $CO_2$ to the oil fields. In addition to the projects underway in West Texas, pipelines from the $CO_2$-rich La Barge gas field in Wyoming have been extended to oil fields in Wyoming and may be extended to North Dakota fields. Natural sources of $CO_2$ in Mississippi are also being tapped. Future sources for $CO_2$ may be coal-fired power plants carbon capture technology is applied.

### *Process Description and Problems*

The gas injection process entails injecting gas into a reservoir to displace oil and move it to a production well (Figure 3).

The process used most often is miscible flooding where the injected gas mixes intimately with the oil across a transition zone between the gas injectant and residual oil. A "piston-like" displacement of the oil overcomes the physical forces holding the oil in the rock and increases its mobility. If the vertical and horizontal sweep efficiency can be maintained, this process results in high oil recovery.

The problem that plagues the gas injection process (and other EOR processes as well) is an uneven displacement of the oil. Since gas has a lower density than oil, the injected gas can override the oil and channel through the top of the formation. Gas override is exacerbated by reservoir layers with higher permeability overlying lower permeability layers. Both of these conditions cause early breakthrough of the gas to the production well which decreases sweep efficiency and leaves bypassed oil in the reservoir. Once the gas breaks through, the path formed will continue to channel the gas and virtually no more oil will be displaced.

The major technical challenge of gas injection is to achieve favorable mobility control and sweep efficiency. Modifying $CO_2$ viscosity is critical to reducing the viscosity differences between $CO_2$ and oil in order to avoid $CO_2$ channeling. Alternating injection of water and gas (water-after-gas or WAG) is one method used to improve sweep efficiency; however this approach has its own drawbacks in that the water can shield the oil from the solvent-like nature of the miscible gas.

DOE research efforts have focused primarily on alternative methods to improve the sweep efficiency of $CO_2$. These methods include the use of foams, chemical gels, and direct $CO_2$ thickening agents.

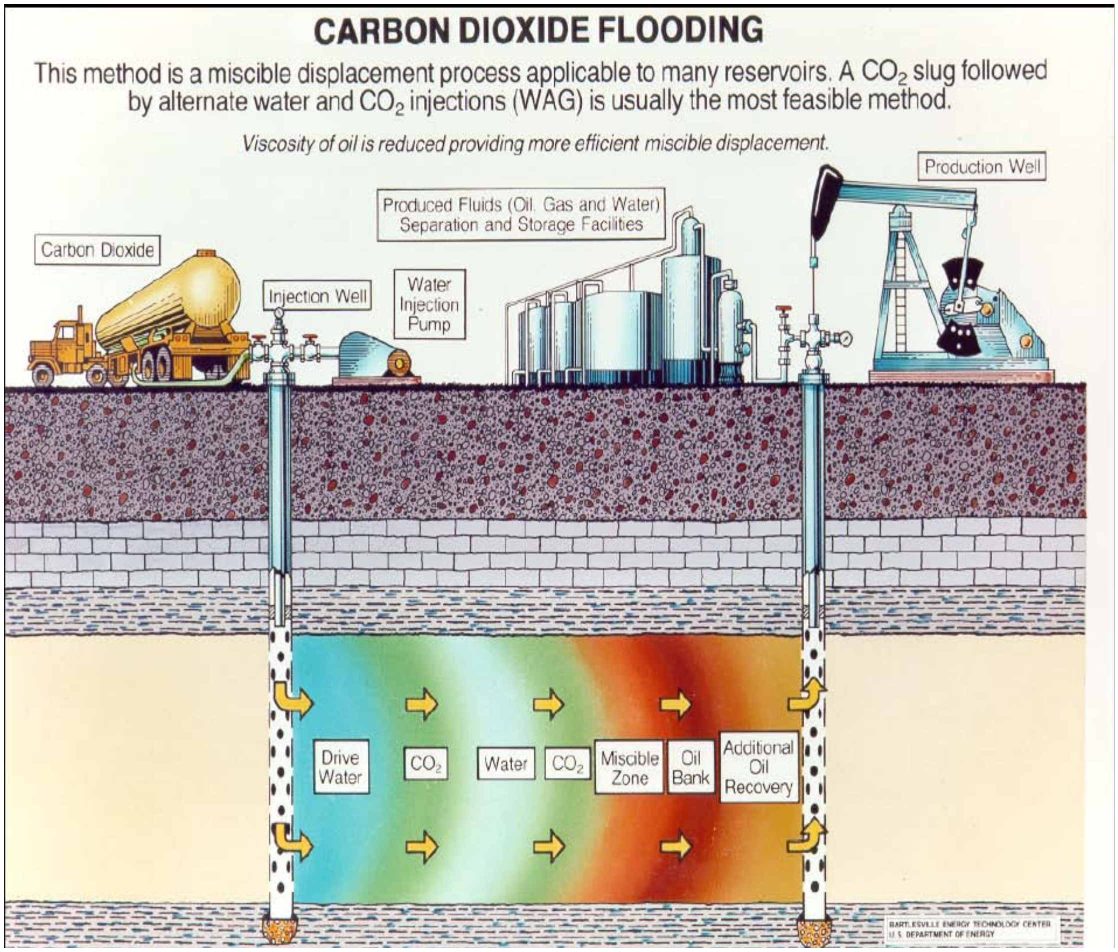


**Figure 3. The $CO_2$ injection and production process.**

## *Significant Technology Development*

From 1978 until about 1988, most of the DOE funding related to gas injection was directed at basic research to understand the fundamental physics of the $CO_2$ recovery process. As the use of $CO_2$ injection began to increase, DOE funding shifted to methods to improve field performance (1988-1996). In 1997 and after, funding shifted towards the development of technologies for improving sweep efficiency and lowering the minimum miscibility pressure; techniques necessary to make the process applicable to more reservoirs.

Between 1977 and 2007 DOE funded 71 projects in gas injection methods for enhanced oil recovery. Figure 4 displays the gas injection funding from 1978 through 2007. The majority of the contracts were awarded to universities. New Mexico Institute of Mining & Technology, the University of Kansas, Stanford University, and the University of Pittsburgh had multiyear contracts and performed a major portion of the work. Of the total number of contracts, 37 were awarded to universities, two to the State of Texas, two to NIPER/IIT Research Institute, three to independent researchers, two to BDM-Oklahoma, and two to the Morgantown Energy Technology Center for in-house research.

The results from these projects led to significant advancements in EOR. Realized benefits included pioneering research that demonstrated that gas injection methods, specifically $CO_2$ injection, could recover additional oil without detrimental effects to the reservoir. The research provided insight into the oil recovery mechanism of gas injection and methodologies to optimize the performance of enhanced oil recovery.

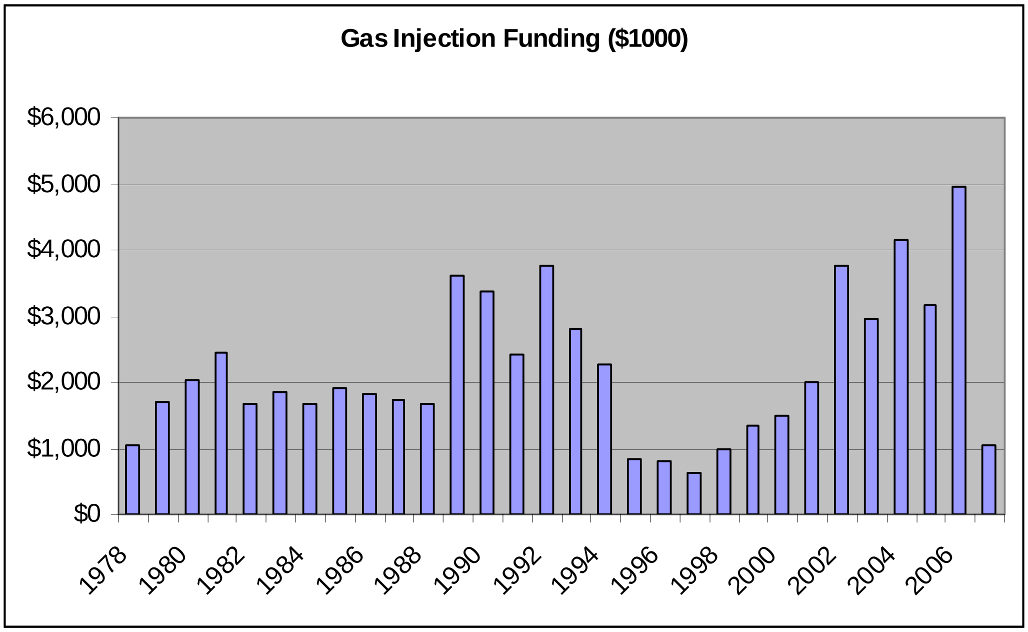


**Figure 4. Funding for gas injection research from FY1978 through FY2007.**

As early as the 1970s, DOE-funded projects assessed the basic fluid properties of $CO_2$ regarding pressure, temperature, and oil composition with an emphasis on minimum miscibility pressure correlations. In the late 1970's four field demonstration projects and 17 laboratory tests on phase behavior, mobility control, corrosion, and target identification were conducted.

$CO_2$ injection was employed in five DOE field demonstration projects conducted from 1975 to 1985 (see Appendix A for more details). The projects had some measure of technical success in defining the necessary criteria for future successful $CO_2$ flood projects. The main problems were the inability to maintain $CO_2$ injectivity, the excessive volumes of $CO_2$ necessary to increase recovery, and failure of $CO_2$ to displace oil under given field conditions. Incremental oil was produced from two of the projects, but only the Weeks Island $CO_2$ flood in Iberia Parish, Louisiana was considered to be cost-effective (Cole et al., 1989)

Throughout the1980s, 20 projects focused on laboratory analysis and computer simulation were funded to study mobility, minimum miscibility pressure, recovery mechanisms, the use of foams to enhance sweep efficiency and model development.

During the early1990's, DOE funded 14 gas injection projects including 12 field demonstrations in the Class Field Demonstration Program (see Appendix A) and 8 laboratory projects related primarily to performance improvement and mobility control. In 2000, DOE's EOR program supported the only U.S. public research on improving reservoir sweep efficiency by modifying $CO_2$ viscosity.

The most significant results of the $CO_2$ and gas injection research carried out under the EOR Program are in the areas of mobility control, understanding the physics of flow mechanisms and phase behavior, modeling gravity drainage, and preventing formation damage from $CO_2$ injection.

## *Selected Project Summaries*

**Enhanced Oil Recovery by $CO_2$ Foam Injection**
**Contract:** DE-AC21-81MC16551
**Performer:** New Mexico State University
**Project Dates:** 1981
**Objectives:** Reports from industry suggested that the use of $CO_2$ to enhance the recovery of oil might be causing formation damage. This project was undertaken to define the mechanisms responsible for formation damage.
**Results:** Although several possible damage mechanisms were identified, the results of the project showed that none were severe enough to destroy the profitability of the recovery process. Laboratory experiments suggested that when a given reservoir is a commercial candidate for $CO_2$ injection, a $CO_2$ project can be implemented while staying alert to the possible need to remedy some future reservoir damage.

**Field Verification of $CO_2$ - Foam**
**Contract:** DE-FG21-89MC26031
**Performer:** New Mexico Institute of Mining and Technology
**Project Dates:** 1989 - 1993
**Objectives:** Conduct a field test using $CO_2$ foam to demonstrate that it can reduce the mobility of $CO_2$ in specific areas, improving the sweep and thereby the effectiveness of a $CO_2$ flood.
**Results:** The $CO_2$ foam field trial demonstrated that well-developed foam could be formed *in situ* and that the foam reduced the mobility of $CO_2$ by one-third of baseline $CO_2$ injection. Incremental oil was produced in three of the 8 producers in the pattern, and the amount of $CO_2$ produced with the oil was dramatically reduced as a direct result of surfactant injection.

**Design and Implementation of a $CO_2$ Flood Utilizing Advanced Reservoir Characterization and Horizontal Injection Wells -- Class II**
**Contract:** DE-FC22-93BC14991
**Performer:** Phillips Petroleum
**Project Dates:** 1994-2001
**Objectives:** Demonstrate the use of horizontal $CO_2$ injection wells to improve sweep efficiency and $CO_2$ flood project economics in the South Cowden field in WestTexas.
**Results:** Two surfactants were identified that improved $CO_2$ foam mobility and diversion. The average production increase from the field demonstration was 200 BOPD. The average rate of productivity increase for seven wells was 92%. Total incremental production after twenty months of $CO_2$ injection was 448 BOPD. Cumulative incremental production was 500,000 bbl at the end of the project in September 2002.
**Project Reports:** Final report BC14991-23, November 2002.

**Application of Reservoir Characterization and Advanced Technology Improves Recovery**
**Contract:** DE-FC22-95BC14936
**Performer:** Bureau of Economic Geology, University of Texas at Austin
**Project Dates:** 1995-2001

**Objectives:** Demonstrate that detailed reservoir characterization data can improve oil recovery from a $CO_2$ flood in the East Ford and Geraldine Ford fields, West Texas.
**Results:** The East Ford unit produced 180,097 bbl of oil from the start of the project through May 2001; essentially all of which can be attributed to the $CO_2$ flood. Application of project technology to East Ford field will result in an ultimate total of 1.7 MMbbl of incremental oil recovery. Technology transfer of project methodology have the potential to benefit development of other Delaware Sandstone reservoirs, which contain 1,558 MMBO of remaining oil.
**Project Report:** Final report BC14936-18, November 2001.

**Prediction of Gas Injection Performance for Heterogeneous Reservoir**
**Contract:** DE-FG22-96BC14851
**Performer:** Stanford University
**Project Dates:** 1996-2000
**Objectives:** Develop methods to accurately predict the performance of the gas injection process, combine theory and experimental data to delineate underlying physical mechanisms, and then to use that understanding to build simulation tools.
**Results:** When gravity segregation and viscous fingering are both important, two-dimensional calculations of displacement performance do not accurately reflect what happens in three-dimensional flows. Simulation techniques were developed that were orders of magnitude faster than conventional simulation, and yet free of the adverse effects of numerical dispersion.

**Synthesis and Evaluation of $CO_2$ Thickeners**
**Contract:** DE-FC26-04BC15533
**Performer:** University of Pittsburgh
**Project Dates:** 2001-2005
**Objectives:** Use molecular modeling techniques coupled with prior experimental results to design, synthesize, and evaluate inexpensive $CO_2$ thickening agents.
**Results:** Successful use of polymer design calculations enabled researchers to synthesize the first non-fluorous $CO_2$-soluble ionic surfactant.

**Improving $CO_2$ Efficiency for Recovering Oil in Heterogeneous Reservoirs**
**Contract:** DE-FC26-02NT15364
**Performer:** New Mexico Petroleum Recovery Research Center
**Project Dates:** 2001-2005
**Objectives:** (1) Increase effectiveness of $CO_2$ mobility control using foaming systems to minimize injectivity losses; (2) Improve understanding of foaming agents and injectivity. Most of the study was laboratory-related, coupled with supporting modeling and field liaison projects.
**Results:** Water-alternating-gas (WAG) coreflood experiments conducted on limestone and dolomite core plugs confirmed that carbonate mineral dissolution and deposition can occur over relatively short time periods (hours to days) and in close proximity to each other. Results of high-pressure/high-temperature/high-velocity gas injection experiments on five different rock samples (sandstones and carbonates) under reservoir conditions reconfirmed—and extended to new conditions—the fact that permeability increases with increasing effective stresses. The results of a series of tests on $CO_2$ foams identified reductions in chemical costs derived from the synergistic effects of co-surfactant systems using a good foaming agent and a less-expensive but poor foaming agent. The required volume of expensive foaming agent was reduced by at least 75%. Additionally, the deleterious effect on injectivity was reduced by as much as 50% using the co-surfactant system, compared with a previously used surfactant system.

**Time-Lapse Seismic Modeling and Inversion of $CO_2$ Saturation for Sequestration and Enhanced Oil Recovery**

**Contract:** DE-FC26-03NT15417
**Performer:** 4th Wave Imaging Corp.
**Project Dates:** 2003-2006
**Objectives:** (1) improve current methods of rock physics and time-lapse seismic reflection modeling for $CO_2$ sequestration and miscible $CO_2$ injection, and (2) develop new methods to estimate changes in pressure, oil saturation, water saturation, and $CO_2$ saturation over time.
**Results:** Investigated new ways to compute fluid properties of oil-water-$CO_2$ mixtures. Developed a 1-D seismic modeling program that uses time-lapse changes in well-log velocities and densities to predict changes in seismic data during $CO_2$ injection. Developed an algorithm that generates time-lapse seismic attribute changes as a function of changes in $CO_2$ saturation and pressure.

## *Thermal Recovery*

Thermal recovery processes are the most effective and most widely used method to produce heavy oil. The U.S. heavy oil reserves are over 100 million barrels of oil in place (National Research Council report, 2000). Current production rates are approximately 301,704 barrels per day and total 5.9% of domestic production. (Moritis, 2006)

### *Process Description and Problems*

Of the three major EOR processes –thermal, miscible gas, chemical – thermal processes dominate, having the greatest certainty of success. Typical recovery factors are in the range of 50-60% of the oil in place.

Recovery of heavy oil is accomplished by reducing the oil viscosity with heat. The two primary methods of delivering heat to the reservoir are steamflooding, where steam is injected into the reservoir, and *in situ* combustion where heat is produced directly in the reservoir by injecting air and burning some of the oil in place. The large majority of thermal recovery projects in the EOR Program were related to steam floods.

The steamflooding process entails generating high-temperature steam on the surface and continually injecting it into the reservoir. As the steam loses heat to the formation, it condenses into hot water, which, coupled with the continuous supply of steam behind it provides the drive to move oil to the production wells. The primary mechanism of the process is the large reduction in oil viscosity, and the resulting improved mobility ratio. Rock and fluid expansion, compaction, and some distillation of the lighter fractions of the oil are also mechanisms that can enhance recovery. Figure 5 illustrates the steamflood process.

A common variation onsteam flooding is cyclic steam injection, also called “huff ‘n‘ puff.” Steam is injected into a well for several days or weeks and then the well is shut in for a period of from several days to a month or more. The steam heats the rock and fluids surrounding the wellbore lowering the viscosity of the oil and increasing the reservoir pressure. The well is then pumped, and the lower viscosity oil flows readily into the well. This cycle is repeated.

Another steam-based recovery process is steam assisted gravity drainage (SAGD). This process relies on the gravity segregation of injected steam, using a pair of parallel horizontal wells. The top well is the steam injector, and the bottom well serves as the producer. Steam rises to the top of the formation, forming a steam chamber. The heated oil or bitumen drains downward under the force of gravity and is captured by the horizontal producing well placed near the bottom of the reservoir.

*In situ* combustion introduces heat into the reservoir by the burning a portion of the oil. The combustion process is initiated by the injection of air and the use of a downhole ignition device. The combustion front is thereafter sustained and propagated through the reservoir by the continuous injection of air. Water is often injected along with the air to improve process effectiveness. The injected water transfers some of the heat from the hot rock behind the combustion front to the rock immediately ahead of the combustion front. A major problem with *in situ* combustion projects is premature breakthrough of the combustion front. Recent studies have suggested ways that the process can be improved by using horizontal wells coupled with gravity drainage concepts.

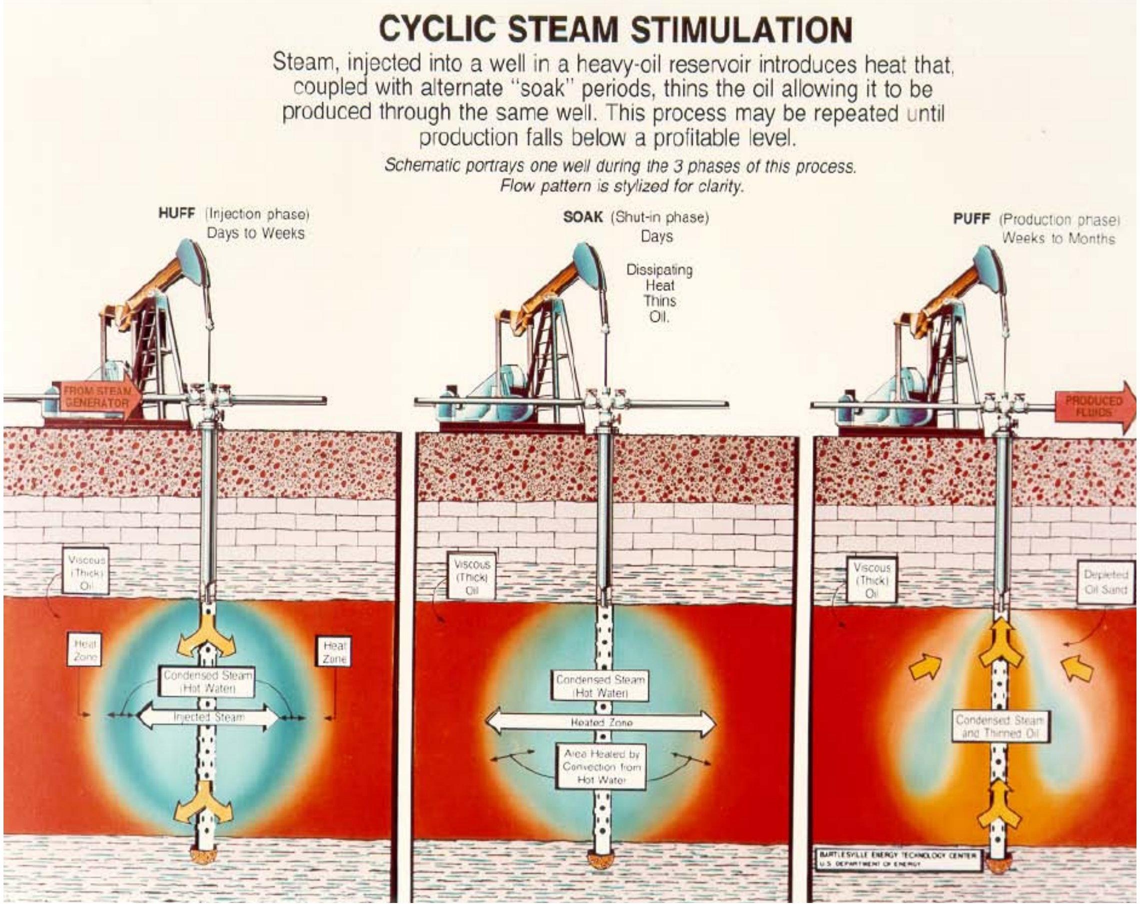


**Figure 5. The cyclic steam flooding process.**

## *Significant Technology Development*

The DOE research program focused on several areas to improve the efficiency, economics, and range of applicability of steamflooding. DOE-supported research evaluated ways to minimize wellbore heat losses, thereby permitting higher quality steam to enter the reservoir. These methods included the development of insulated tubing, the evaluation of downhole steam generation, and the stimulation of reservoirs to permit higher injection rates. Other areas of DOE support included the evaluation of the cogeneration of steam and electricity as a means for reducing costs, and the development of foams and gels that have the potential of minimizing the channeling and gravity override that can occur in steam injection projects.

Between 1978 and 2007 seventy-seven thermal/heavy oil research projects were funded by DOE's EOR program (Figure 6). The program goals were to improve efficiency, test new parameters of thermal recovery, assess the risks of new thermal methodology, and further the development of new heavy oil recovery technologies in areas untried by industry. Large multi-year programs were developed at Stanford University, University of Southern California, and Lawrence Livermore National Laboratory.

Major advancements in the thermal EOR program include developing techniques to image multiphase flow during steamflooding, determining the dynamics of an *in situ* combustion process, developing foams and other chemicals to enhance steamfloods, and developing methods to characterize reservoirs during a steamflood.

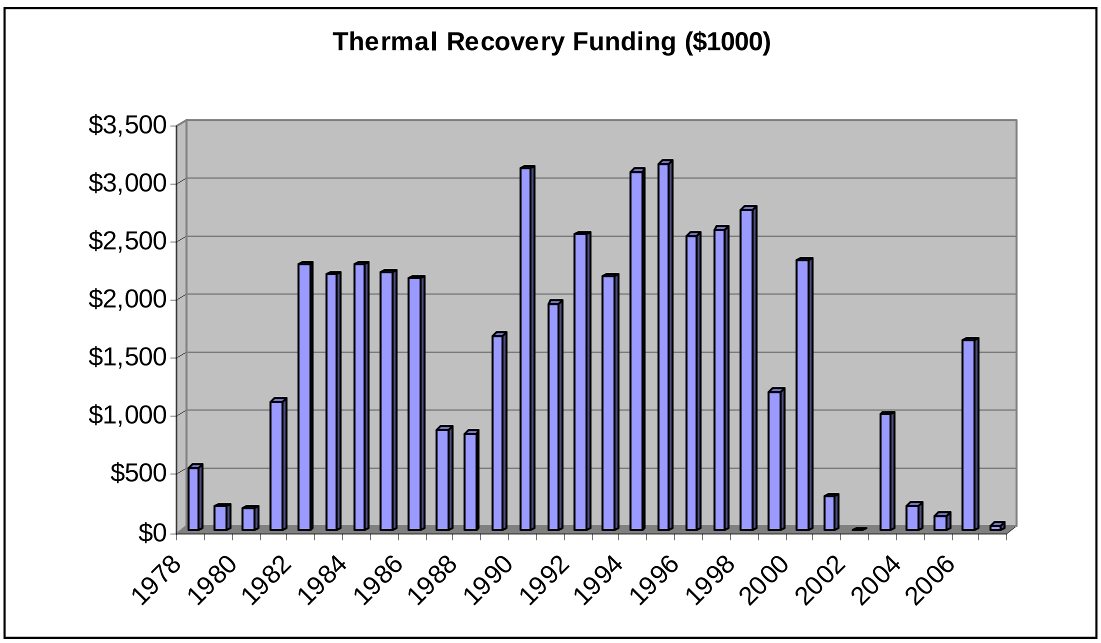


**Figure 6. Funding for thermal recovery research from FY1978 thru 2007**

## *Selected Project Summaries*

**Research on Oil Recovery Mechanisms in Heavy Oil Reservoirs**
**Multiple Contracts:** 76ET12058, 81SF11564, 87BC14126, 90BC14600, 96BC14994
**Performer:** Stanford University
**Project Dates:** 1981-1996
**Objectives:** Pursue EOR research for heavy oil reservoirs.
**Results:** Established the Stanford University Petroleum Research Institute (SUPRI) in 1976. Amoco, ARCO, Chevron, Exxon, Mobil, OXY, Texaco, PDVSA, El Aquitaine and Shell International, participated in the program. Key results included:

- Delineated the effect of temperature on the absolute and relative permeability of sands and sandstones.
- Applied X-ray CT for high resolution imaging of multiphase flow in homogeneous and heterogeneous porous media. This was the first study using CT imaging to be made available to the public.
- Developed a methodology for laboratory testing of *in situ* combustion dynamics of displacement and kinetics of oxidation reactions, imaged *in situ* displacement in porous media, and developed correlations for predicting field wide *in situ* combustion performance.
- Determined pore-level mechanics of foam generation and mobility control in steamflooding, developed a mechanistic model of foam displacement, and developed methods to apply foam in a steamflood.
- Determined the feasibility and mechanisms of thermal recovery from low permeability fractured porous media.
- Developed well testing technology for thermal recovery projects.

**Heavy Oil Recovery Mechanisms**
**Multiple Contracts:** 77ET12075, 81SF11571, 84SF11999, 87BC14126, 90BC14600, 96BC14994, 99BC15211
**Performer:** University of Southern California
**Project Dates:** 1977-2003
**Objectives:** Conduct fundamental studies in selected areas of thermal recovery.
**Results:** Key results included the following:

- Advanced the science surrounding chemical additives for improving the performance of steamfloods by: (1) developing a methodology to measure relative permeabilities as a function of oil-water interfacial tension; (2) relating surfactant adsorption as a function of temperature; (3) developing a chemical-steam simulator; and (4) analyzing foams and additives for mobility control.
- Determined flow properties of liquid-to-vapor phase change in porous media, including the identification of condensation-evaporation phase change and heat transfer affects; and determined the onset of gas flow in solution gas drive in porous media.
- Identified the effect of reservoir heterogeneity on thermal recovery at various scales.
- Modeled flow properties of non-Newtonian fluids including foams and Gingham plastics.
- Developed optimization methods to increase the effectiveness of thermal recovery processes.
- Improved understanding of oil recovery from fractured reservoirs.

**Improved Oil Recovery/Thermal Processes for Heavy and Light Oil Recovery**
**Contract:** DE-FC22-83FE60149
**Performer:** National Institute for Petroleum Energy Research (NIPER) managed by Illinois Institute of Technology Research Institute (1983-1993), BDM-Oklahoma (1993-1998)
**Project Dates:** 1983-1998
**Objectives:** (1) improve the understanding of the basic mechanisms responsible for thermal light and heavy oil production, (2) accelerate improved thermal technology development, (3) evaluate thermal processes for light and heavy oil (1980s); (4) conduct feasibility studies of various thermal processes for heavy oil (1990s).
**Results:** Key results included:

- A steam injection processes handbook for independent producers that reamins a standard reference at major petroleum engineering colleges and universities. Over 6,000 copies have been distributed and the handbook has been translated into Chinese and Spanish.
- Conducted U.S. heavy oil resource assessment and managed a database on heavy oil resources. Regional feasibility studies were conducted in the major basins in U.S. including the Appalachian, Illinois and Michigan basins, Rocky Mountain region, Mid-Continent region and the California basins.
- Designed and constructed a high-temperature, high-pressure laboratory employing a scaled, 3D physical model and developed procedures and apparatus to conduct laboratory steamfloods at field conditions.
- Assessed potential heavy oil recovery using gas injection processes. Studies of Schrader Bluff field in Alaska showed that carbon dioxide/natural gas liquid mixtures can reduce crude oil viscosity by up to 70%.

**Oil Field Characterization and Process Monitoring Using Electromagnetic Methods; Electrical Resistivity Tomography (ERT) Measurements at Mobil Oil Company Lost Hills Oil Field, California**
**Multiple Contracts** FEW 6038, FEW 6036, W-7405-Eng-48
**Performer:** Lawrence Livermore National Laboratory
**Project Dates:** 1984 - 2001
**Objectives:** Develop and apply surface and borehole electromagnetic (EM) methods for heavy oil-field characterization and monitoring of *in situ* changes in electrical conductivity during EOR operations. Provide a solution using multiple-use wells, which are capable of producing fluids, stimulation and monitoring well progress.
**Results:** Key results included:

- Development and application of electromagnetic (EM) methods to characterize heavy oil reservoirs during enhanced oil recovery operations. This work included conducting 3-D forward modeling of crosswell EM time-lapse imaging; developing instrumentation and software tested in a single borehole EM induction system; conducting a long-term crosswell EM survey in conjunction with through-steel-casing monitoring; and field tests that recorded electromagnetic signatures produced during hydrofracturing.
- Developed electrical resistance tomography (ERT) as an extension of EM technology that can map subsurface resistivity distribution and reservoir temperature over time, and provided data to simulate interwell fluid flow.
- Developed innovative and economic heating processes that included: Ohmic heating, a hybrid thermal stimulation that uses electric heat to preheat the reservoir and horizontal electrodes to heat the pay zone more effectively. Research showed that 6 months of preheating will substantially accelerate production and result in higher cumulative oil recovery.

**Oil Recovery from Naturally Fractured Reservoirs by Steam Injection Methods**
**Contract:** DE-AC22-90BC14661
**Performer:** University of Texas at Austin
**Project Dates:** 1990-1995
**Objectives:** Quantify the amount of oil producible by steam recovery methods and develop a numerical model for predicting oil recovery in naturally fractured reservoirs during steam injection.
**Results:** The research effort determined how to measure and model thermal expansion and capillary imbibition rates at relatively low temperatures in various lithologies and matrix block shapes. Apparatus was designed to measure thermal expansion, capillary imbibition rates at high temperature; maximum gas saturations within a matrix block; and thermal conductivity and diffusion of porous media. The researchers also developed a dual porosity thermal reservoir simulator to model temperature affects and tested the simulator in a series of experimental fractured reservoir simulations.

**Measuring Wellbore Heat Losses in an Active Steam Injection Well**
**Contract:** DE-AC22-89BC14260
**Performer:** Kawasaki Thermal Systems, Inc.
**Project Dates:** 1989-1992
**Objectives:** Establish heat loss data from an active steam injection well to validate a wellbore heat loss software program.
**Results:** Data was collected from a test well in the Kern River field, California. Six steam injection test cases were run. The thermal conductivity of the casing string allowed the measurement of heat loss at couplings. Data from heat flux sensors were used to develop a wellbore heat loss model and to develop SIMSTEAM software.

**Reactivation of an Idle Lease to Increase Heavy Oil Recovery using Steam Drive Technology—Class 3**
**Contract:** DE-FC22-95BC14937
**Performer:** University of Utah
**Project Dates:** 1995-2001
**Objectives:** (1) return a 40-acre shut-in lease of the Midway-Sunset field, CA to commercial production; (2) accurately describe the reservoir and recovery process; and (3) convey the details of this activity to the petroleum industry
**Results:** Established commercial production through a successful steamflood design based on integration of geologic characterization, geostatistical modeling, reservoir simulation, and petroleum engineering. Total cumulative incremental production totaled over 2.52 million barrels of oil from 1996 to 2003. This effort spurred the drilling of an additional 54 wells from 1999-2002 where daily production rose to over 1,500 bbl in the second half of 2000. AERA transferred the steamflood technology to three adjoining leases. Recoverable reserves went from 0 in 1994 to 4.4 million at the end of the project.

## Chemical Flooding

Chemical EOR processes have the greatest potential to recover oil trapped in the reservoir by capillary forces and are the only processes that have been successfully demonstrated in the field as being capable of recovering oil from low pressure, depleted oil reservoirs (NRC Report, 2001). However, chemical EOR is not widely used (there were zero chemical EOR projects in 2006 (Moritis, 2006). At least part of the reason for this fact is the perception that the cost of the chemical injectants is too high to justify these projects. This may in fact be true in cases where hydrocarbon-based surfactants are used as the injectant. However, a comparison of the cost of the injected fluid plus capital costs for alkaline-surfactant-polymer flooding and other EOR processes with the average finding and development costs for new fields showed that the average finding and development costs from 1993-1997 ($5.42 per barrel) were significantly greater than the cost of a steamflood ($4 per barrel), $CO_2$ injection ($4.05 per barrel), alkaline-surfactant-polymer flooding ($2.98 per barrel) and simple polymer flooding ($1.69 per barrel) (Casteel, 2000).

### *Process Description and Problems*

Chemical methods include the use of polymers, surfactants, alkaline enhanced chemicals, and chemical gels. Figure 7 illustrates a chemical flood where water is first injected as a preflush to condition the reservoir, followed by chemicals that reduce interfacial tension to mobilize the oil, followed by chemicals that reduce channeling of the water that is used as a driving fluid to move the chemicals and resulting oil bank to the production wells. Two common types of chemical floods are surfactant-micellar-polymer floods and alkaline-surfactant-polymer floods.

**Surfactant-Micellar-Polymer Methods**

The micellar-polymer flood method uses a solution usually containing a mixture of a surfactant, co-surfactant, alcohol, brine and oil that acts to reduce the interfacial tension and mobilize oil out of the reservoir pores. To further enhance production, polymer-thickened water is injected after the micellar polymer fluids for improved sweep efficiency. Fresh water is injected behind the polymer and before the drive water to prevent contamination of the chemical solutions.

**Alkaline-Surfactant-Polymer (ASP) Methods**

The alkaline-surfactant-polymer (ASP) process evolved from early studies on micellar-polymer flooding. The ASP process is based on the discovery that surfactants are generated *in situ* when certain crude oils that contain organic acids react with alkaline (e.g., sodium hydroxide) solutions. Polymer is added to protect the initial chemical slug from early dissipation by the driving water phase. The advantages of this process are its low cost relative to other chemical processes and a recovery factor as high as 30% of the original oil in place (Casteel, 2000).

Cost is a major disadvantage in chemical EOR. The cost of the chemicals may account for more than 50% of the total project cost. Chemicals can easily be lost by adsorption on the rock surfaces or mixing and dilution with reservoir brine, requiring additional volumes to be pumped to achieve the design concentrations and increasing the cost even further. Polymer floods are less expensive, but they have less recovery potential as they do act to reduce the forces holding the oil in place.

Industry experience has shown that chemical flooding is capable of recovering a significant amount of oil (up to 28%) especially with the later-generation surfactants. However, micellar polymer flooding may be the riskiest type of EOR process because it demands difficult design decisions, requires large capital investments, and is adversely affected by reservoir heterogeneities. A micellar-polymer surfactant flood must be designed for a specific combination of crude oil and reservoir rock, taking into account such factors as salinity, temperature, pressure and clay content (Lake et al., 1992). Alkaline flooding, with moderate costs and good recovery is perhaps a more promising technique.

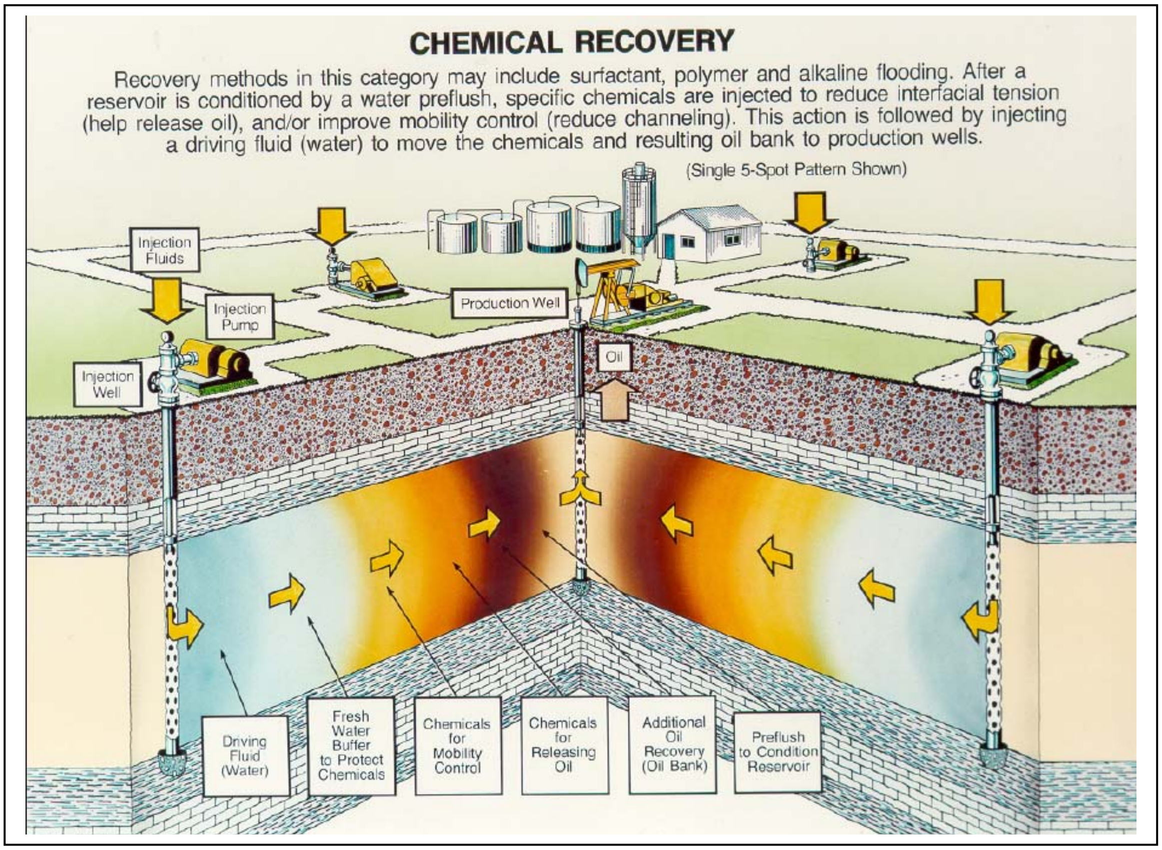


**Figure 7. The chemical flooding process.**

**Crosslinked Polymers and Chemical Gels**

Crosslinked polymers and chemical gels are used to improve injection profiles and increase sweep efficiency. The high viscosity fluids plug high permeability zones in a reservoir to prevent channeling of injected fluids and early breakthrough of fluid fronts into the producing well. During waterfloods, polymer gels are used to plug up the high permeability zones that have been swept of oil so that the injected water preferentially flows into the lower permeability zones that have not yet been contacted.

The plugging characteristics of polymer gels are also used as a method for reducing the volume of water that is produced along with the oil. Produced water is a major challenge for the petroleum industry in terms of water handling and disposal costs, particularly in light of the heightened level of concern for reducing environmental impacts. Reduced water production directly reduces operating costs. In the U.S. more than 8 barrels of salt water are produced for every barrel of oil - totaling an annual production of more than 25 billion barrels of salt water (Casteel, 2000)

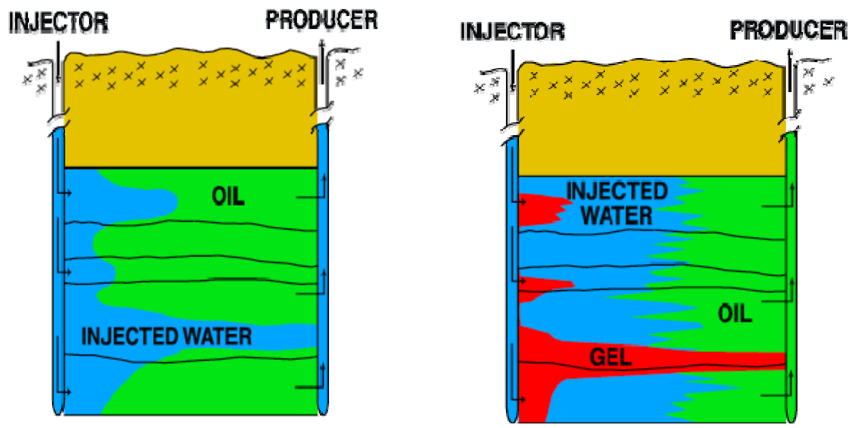


**Figure 8. Polymer gels improve injection profile.**

### *Significant Technology Development*

DOE conducted a considerable amount of research in the 1970s and 1980s on the development of micellar-polymer flooding together with other chemical processes. This research focus was selected because micellar-polymer flooding was in the early stages of development and commercial activity had not begun. The research conducted by DOE and by industry was responsible for the enormous progress made in the development of the technology. A highly successful field test was conducted by Exxon using the latest generation of surfactants that could tolerate high salinity and hardness. Unfortunately the technology did not progress because the extremely low oil prices in the 1980s and 1990s made the cost of such EOR unjustifiable. DOE's research programs continued during this time with a shift toward systems that cost less and could conceivably be economic at lower oil prices. The alkaline-surfactant-polymer (ASP) process emerged from these early studies and is in commercial use today (Casteel, 2000).

Polymer flooding was introduced as a new EOR process in the 1960s and later developed into a commercial process. The DOE research programs focused on ways to improve the stability of polymer, extend the range of conditions where the polymers could be applied, and develop new ways that polymer could be used. DOE had a major role in the development of polymer gel systems that are used commercially today for improving the profiles in injection wells. Similarly, DOE has made large contributions to the development of polymer gel systems that are used to reduce water production.

There were several industry sponsored surfactant projects conducted in the late 1970s to mid 1980s. Most of the projects were technical successes, but were not economic due primarily to the loss of surfactant to adsorption onto reservoir rock, or dissolution into the reservoir brine or oil. By 2000 every major oil company had essentially stopped work on surfactant flooding processes (NRC, 2001).The DOE was one of the few remaining resources for reliable and objective information on chemical flooding.

The Department of Energy funded 94 research projects addressing chemical enhanced oil recovery processes from 1975 to 2007. Funding levels for chemical flooding are presented in Figure 9. Fifty-two percent of the projects were conducted by universities, 32% by research organizations, 6% by service companies, 4% by national laboratories, 4% by government agencies, 1% by a consultant, and 1% by an independent operator.

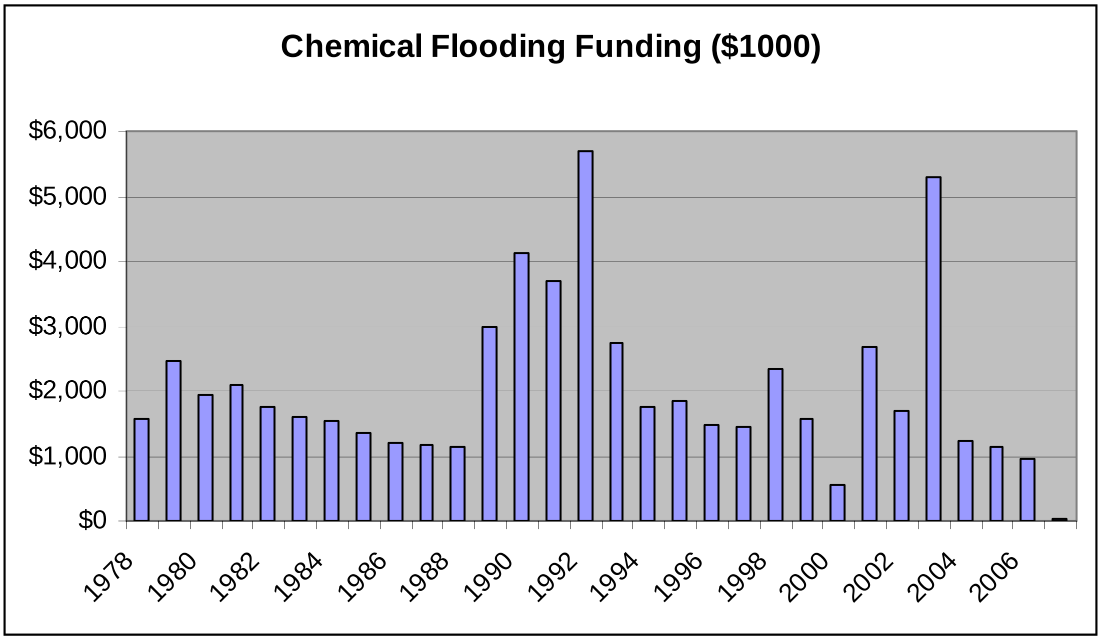


**Figure 9. Funding for chemical flooding research from FY 1978 thru 2007.**

## *Selected Project Summaries*

**Surfactants and Micellar Polymer Methods**

**Extraction Research, Improved Recovery Processes - Chemical Recovery**
**Contract:** 98-A03 Task 02 under DE-AC22-94PC91008
**Performer:** National Institute for Petroleum Energy Research (BDM-Oklahoma)
**Project Dates:** 1997-1998
**Objectives:** Investigate the feasibility of mixed surfactant systems in increasing oil recovery
**Results:** Demonstrated that surfactant chemical systems can be adjusted to have optimal properties over a wide range of reservoir conditions. Showed that surfactant loss can be reduced by two orders of magnitude, salinity tolerance can be increased up to 20% NaCl, and temperature tolerance can be increased up to 90°C by combining effective oil-mobilizing surfactant systems with other chemicals.

**Optimization of Surfactant Mixtures and Their Interfacial Behavior for Advanced Oil Recovery**
**Contract:** DE-AC26-98BC15112
**Performer:** Columbia University
**Project Dates:** 1998-2001
**Objectives:** Evaluate novel mixtures of surfactants to design cost-effective processes that are compatible with reservoir conditions and minimize chemical loss. Specifically, study the adsorption/desorption of mixed surfactants on reservoir rock.
**Results:** Microstructural properties of the adsorbed surfactant layer that control rock wettability were determined *in situ* for the first time. A new model was developed for mixed micellization, taking into account synergy and competition between different species in adsorption and desorption. A new hypothesis of co-existence of mixed micelles was prepared based on results for mixed cationic-anionic surfactant system.

**Optimization of Surfactant Mixtures and their Interfacial Behavior for Advanced Oil Recovery; Behavior of Surfactant Mixture at Solid/Liquid and Oil/Liquid Interface in Chemical Flooding Systems; Mineral-Surfactant Interactions for Minimum Reagents Precipitation and Adsorption for Improved Oil Recovery**
**Multiple Contracts:** DE-FC26-01BC15112, DE-FC26-02BC15312, DE-FC26-03BC15413
**Performer:** Columbia University
**Project Dates:** 1998-2007
**Objectives:** Increase understanding of interactions between reservoir rocks of varying mineralogy and surfactants and polymers. Determine interaction effects on adsorption, wettability, and interfacial tension.
**Results:** Provided new data on interactions between typical reservoir minerals of quartz, alumina, calcite, dolomite, kaolinite, gypsum, and pyrite that increases understanding of rock-fluid interactions. Developed predictive models that included minerals, surfactants/polymers, and reservoir conditions such as temperature and salinity.

**Innovative Copolymer Systems for In Situ Rheology Control in Advanced Oil Recovery; Stimuli-Responsive Copolymers with Enhanced Efficiency in Reservoir Recovery Processes; Smart Multifunctional Polymers**
**Multiple Contracts** : DE-AC26-98BC15111, DE-FC22-01BC15317, DE-FC26-03NT15407
**Performer:** Mississippi State University
**Project Dates:** 1998-2007
**Objectives:** Develop new copolymers with improved reservoir recovery efficiency. Synthesize, characterize, and evaluate stimuli-responsive polymer systems that can be formulated into “smart” fluids with better rheological and interfacial properties for EOR.
**Results:** Developed new “smart” copolymers that can control fluid mobility and/or conformance by altering viscosity and/or permeability. Triggers based on pH, salt or temperature variations enable the smart polymers to react to reservoir conditions and stimulate oil flow.
Developed a rheometer that aids in the investigation and development of advanced polymer systems at various flow conditions.

## Alkaline Surfactant Polymer Methods

**Evaluation of the SHO-VEL-TUM Alkaline-Surfactant Project; Lab Feasibility Study of an ASP System for the Karamay Reservoir - Intratec**
**Contract:** 75-99SW45030: 60/94B02 Task 04 under DE-AC22-94PC91008
**Performer:** National Institute for Petroleum Energy Research (IlT Research Institute, BDM-Oklahoma; Troy French, Consultant)
**Project Dates:** 1994-1995; 1998-1999
**Objectives:** Demonstrate the effectiveness of Alkaline Surfactant Polymer (ASP) flooding technology in the Sho-Vel-Tum field, OK
**Results:** An ASP pilot project was designed based on laboratory studies. Coreflood tests determined that oil recovery was highest when alkaline surfactant was followed by polymer and when an alkaline preflush was used in cores that were saturated with brine containing divalent ions. The ASP flooding technology was successfully demonstrated in a pilot area in the Sho-Vel-Tum field. By February 1999, approximately 12,600 barrels of oil (20% of the original oil in place) were produced. After the ASP flood, daily production leveled out at about 22 barrels of oil per day representing a fivefold increase over preflood rates.

## Crosslinked Polymers and Chemical Gels

**Using Chemicals to Optimize Conformance in Fractured Reservoirs**
**Contract:** DE-AC26-98BC15110
**Performer:** New Mexico Petroleum Recovery Research Center
**Project Dates:** 1998-2001
**Objectives:** Develop an improved polymer gel technology to reduce water production from fractures.
**Results:** A polymer gel was developed that effectively reduced water production. During the 1990s, more than 2,000 gel treatments used the gel developed in this project with reports of reducing production of over 500,000 barrels of water per day (Casteel, 2000).

**Increased Oil Recovery from Mature Oil Fields Using Gelled Polymer Treatments**
**Contract:** DE-AC26-99BC15209
**Performer:** University of Kansas
**Project Dates:** 1999-2002
**Objectives:** Provide a mechanistic understanding of how gelled polymer treatments work, particularly the chemistry, the placement process and the performance of the treatments.
**Results:** Field-tested polymer gel systems developed for sweep improvement in southeastern Kansas oil fields, resulting in both reduction of water channeling and increased oil production. Discovered the mechanisms that control in-depth treatment of porous rock using chrome-polymer systems and developed a mathematical model that simulated this behavior. Developed and tested two gel systems in sandstone cores that effectively reduced the permeability to carbon dioxide at supercritical conditions to improve sweep efficiency in $CO_2$ injection projects.

## *Microbial Enhanced Oil Recovery (MEOR)*

MEOR entails injecting a mixture of bacteria and a nutrient into a reservoir or providing a nutrient to feed indigenous bacteria in the reservoir. The natural by-products of certain strains of bacteria alter the permeability of an oil reservoir to divert more of the water from a flood into the less permeable portions of the reservoir to recover some of the bypassed oil. Microbes can also be used to remove paraffin buildup in the perforations around a wellbore. The environmental industry has adapted technologies developed in the MEOR programs for bioremediation of oil spills. Because much of the contamination in groundwater is from petroleum-based materials, the same microbial technologies are being used for groundwater and soil remediation. The most common and least expensive form of cleanup technology for both soil and groundwater contaminated with organic compounds is bioremediation.

### *Process Description and Problems*

In MEOR, bacteria metabolize a carbon source such as oil or molasses and produce surfactants, polymers, biomass, and gases such as $CH_4$, $CO_2$, $N_2$, $H_2$ as well as solvents and certain organic acids. The oil recovery mechanisms in MEOR are those of the classic chemical and gas methods, which include interfacial tension reduction, emulsification, wettability alteration, improved mobility ratio, selective plugging, viscosity reduction, oil swelling and increased reservoir pressure due to the formation of gases. Increases in permeability can result from the acids formed.

DOE has been a leader in the development of MEOR technology (Casteel, 2000). Figure 10 illustrates the MEOR flooding process. MEOR has two distinct advantages: (1) bacteria do not require large amounts of energy, and (2) the cost of the primary injectant (bacteria) is not dependent on the price of crude oil as with many of the other EOR processes, either as a direct component or as a fuel. Because microbial growth occurs at exponential rates, it is possible to produce large amounts of useful products rapidly from inexpensive and renewable resources.

Consequently, MEOR has the potential to be more cost-effective than other EOR processes. Recent studies have also shown that several microbially produced biosurfactants have interfacial tension activities that compare very favorably with chemically made surfactants.

The MEOR process was evaluated in DOE's EOR Program for the following different applications:

- Microbial Well Stimulation, with major applications in heavier oil reservoirs with paraffin and asphaltene deposit problems
- Microbial Enhanced Waterflooding, which requires the transport of nutrients over a long distance within the reservoir and is still in the development phase; and
- Profile Control and Sweep Improvement, which depends on microbes that produce polymers, and biomass for selective plugging of high permeability zones.

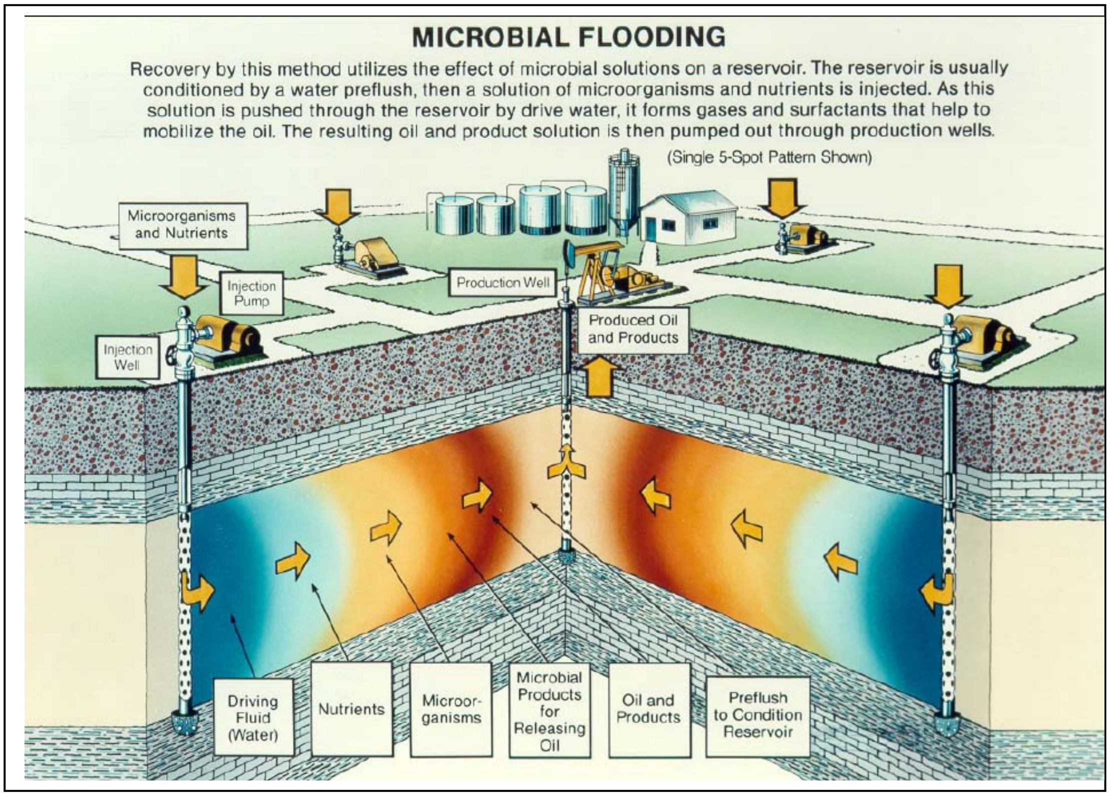


**Figure 10. The MEOR process.**

## *Significant Technology Development*

DOE funded the first MEOR projects in the early 1980s when they were classified as novel processes. There was virtually no MEOR production until the early 1990s when MEOR classification was changed from a novel process to a class of its own. In 1990, funding was substantially increased (Figure 11).

Between FY1980 and FY2007, DOE funded 51 projects in MEOR technology. Fifteen organizations were sponsored with the majority of contracts supporting continuing work at the University of Oklahoma and NIPER. Of the total contracts, 18 went to universities, 12 to NIPER, 4 to national laboratories, 4 to independent producers, and one to a state. There are several projects that show promise and may produce significant oil revenues in the next 5-10 years.

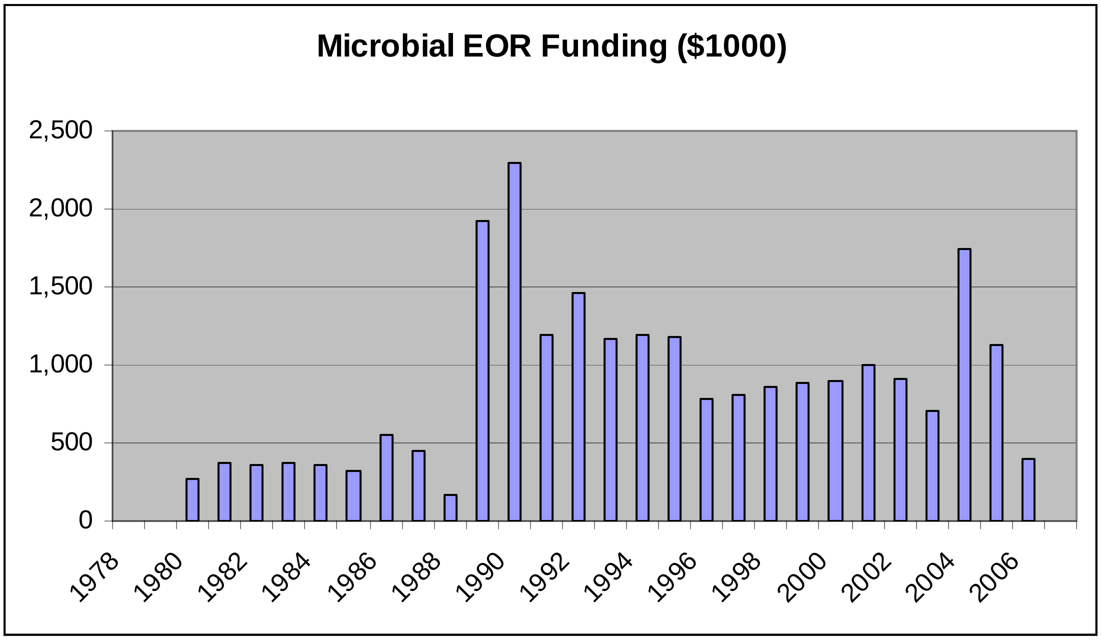


**Figure 11. Funding for microbial EOR research from FY 1980 thru 2007.**

## *Selected Project Summaries*

**Biotechnology – Microbial Improved Oil Recovery (MIOR)**
**Contract:** 12 contracts
**Performer:** NIPER/ ITT Research Institute, BDM-Oklahoma
**Project Dates:** 1983-1998
**Objectives:** Develop an engineering methodology for designing and applying microbial systems to improve oil recovery.
**Results:** This research has improved the understanding of the mechanisms of oil mobilization by microbial formulations and the transport of microbes and their metabolites in porous media, through the implementation of two microbial-improved waterflood field pilots. The concepts and data developed in this work have formed the basis of applied research needed to develop an engineering methodology for designing and optimizing microbial formulations for specific field applications.

Microbial enhanced oil recovery process field tests conducted by NIPER demonstrated 13% and 20% improvements in oil recovery rates. It is estimated that 5-6 million bbls of oil could be recovered by the application of MEOR technology. Single well MEOR treatment demonstrated a cost-effective biotreatment technology to prevent and remove well-damaging agents such as paraffin, hydrogen sulfide and iron sulfide, and scale. Treatment of 165 wells in 15 reservoirs in Oklahoma, Kansas, Texas, New Mexico and Wyoming showed that all treated wells had decreases in hydrogen sulfide levels. Field data showed an increase in production and reduced operating costs.

Microbial waterflooding technology was developed and patented, and licensed to BioEngineering International, Inc. to commercially apply the technology to field treatments.

**Microbial Enhancement of Oil Production from Carbonate Reservoirs; Quantification of Microbial Products and Their Effectiveness in Enhanced Oil Recovery; Development of More Effective Biosurfactants for Enhanced Oil Recovery; Use of Microorganisms in Enhanced Oil Recovery; Microbial Field Pilot Study; Development of Microorganisms with Improved Transport and Biosurfactant Activities for Enhanced Oil Recovery; Development of an In Situ Biosurfactant Production Technology for Enhanced Oil Recovery; Microbial Field Pilot Study**
**Multiple Contracts:** 80BC10300, 86BC14084, 89BC14246, 90BC14202, 90BC14662, 98BC15113, 02NT15321, 04NT15522
**Performer:** University of Oklahoma
**Project Dates:** 1980-1993, 1998-2002
**Objectives:** This research program was a multidisciplinary effort to investigate microbial plugging as a means for improving sweep efficiency, biosurfactant production, molecular engineering of the surfactant structure, and performing engineering studies to determine the effectiveness of biosurfactants in oil recovery.
**Results:** Pioneering work that determined the fundamental processes by which micro-organisms grow in porous media and was the first to demonstrate that oil reservoirs are not sterile environments but contain indigenous micro-organisms that can be cultivated to improve oil recovery. Experimentally demonstrated that oil recovery is proportional to biosurfactant production. Developed the first mathematical model to simulate microbial activity in porous media and to predict permeability reduction. Developed a three-dimensional, three-phase, multiple component numerical simulator. (Report DOE/BC/14662-15). Developed experimental protocols for MEOR research which are now standard practice.

**Innovative MIOR Process Utilizing Indigenous Reservoir Constituents**
**Contract:** DE-FC22-99BC15214
**Performer:** Geo-Microbial Technology
**Project Dates:** 1999-2003
**Objectives:** Develop and demonstrate the capability of a unique *in situ* biosystem to increase oil recovery in model core studies.
**Results:** Made significant contributions to the basic understanding of using the beneficial properties of bacteria to improve oil recovery. Microbial populations were isolated and found to grow on low-cost inorganic nutrients in sand pack models. Oil recovery in the sand pack increased up to 19% more than waterflood recovery, and the polymer producing cultures were isolated and used to reduce permeability by as much as 40%. The biosystem designed in the project was successfully field tested in California in 2002.

**Bio-Engineering High Performance Microbial Strains for MEOR by Directed Protein Evolution Technology**
**Contract:** DE-FC26-04NT15525
**Performer:** California Institute of Technology
**Project Dates:** 2004-2007
**Objectives:** (1) apply advanced bio-engineering methods to increase bacteria biosurfactant production to commercially useful rates, and (2) implant the genetic information for rapid biosurfactant production into microbes adaptable in an oil reservoir environment
**Results:** Laboratory techniques were developed to create and evaluate mutated bacteria for their increased ability to make biosurfactants. The production rates are expected to be several orders of magnitude higher than the naturally occurring strains. The bio-based surfactant alternatives developed in this project are environmentally friendly, come from renewable resources, and are expected to cost less than conventional chemicals.

**Microbial Enhanced Oil Recovery - Surfactant from Waste Products and Biotechnologies for Oilfield Application**
**Contract:** FEW 5AC312
**Performer:** Idaho National Engineering and Environmental Laboratory
**Project Dates:** 1989-2004
**Objectives:** Investigate the application of biotechnology for exploration and production and for the mitigation of detrimental field conditions.
**Results:** Increased understanding of microbial mechanisms responsible for oil production with emphasis on heavy oils. Documented the applicability of microbial surfactants that were either generated in situ or injected after generation on the surface. Developed instrumentation to evaluate interfacial tensions by video image analysis and to measure the changes induced by microbial surfactants. Investigated agricultural sources of surfactants from high-starch waste streams from potato processing. Designed and operated a bioreactor for surfactant production and separation in a single step. Generated a patent on MEOR processes.

**Microbial Selective Plugging Technology**
**Contract:** DE-AC22-90BC14664, DE-AC26-99BC15210
**Performer:** Mississippi State University
**Project Dates:** 1990-1999
**Objectives:** Develop information on the bacteria indigenous to oil reservoirs and determine their potential role in MEOR.
**Results:** Significant numbers of microorganisms were found in the 5 reservoirs examined with each reservoir having a distinctive bacteria population. A total of 37 pure cultures were analyzed and all grew anaerobically and produced one or more products of potential value to MEOR including gas, acid, emulsifiers, polymers and solvents.

**The Use of Indigenous Microflora to Selectively Plug Porous Zones – Class 1**
**Contract:** DE-FC22-94BC14962
**Performer:** Hughes Eastern
**Project Dates:** 1994-1999
**Objectives:** Demonstrate the ability of indigenous microorganisms to preferentially plug the more porous zones of previously water swept areas of the North Blowhorn Field, Alabama.
**Result:** Successfully demonstrated that stimulation/growth of *in situ* bacteria can divert injected fluids into lower porosity zones and improve sweep efficiency of waterfloods. The microbial treatment of the reservoir extended the life of the reservoir by 5 years with a total increase of 595,000 bbls of oil above natural decline. By December 1998 69,000 BO had been produced by MEOR.
**Project Report:** Final report BC14962-24, November 1999
**The Development of Luminescent Bacteria as Tracers for Geological Reservoir Characterization**
**Contract:** DE-AC22-90BC14666
**Performer:** Farleigh Dickinson University
**Project Dates:** 1990-991
**Objectives:** Develop a low-cost method for small independent oil companies to define reservoir characteristics to improve oil production with a biological tracer
**Results:** Developed a bioluminescent tracer to improve reservoir characterization and environmental monitoring. Three luminescent bacteria strains that could be distinguished with the human eye were found to be tolerant to variations in nutrient additions, and reservoir salts and temperature.

## *Improved Waterflooding*

### *Process Description and Problems*

Waterflooding is by far the most widely applied method for improved oil recovery. It accounts for more than one-half of U.S. domestic oil production. Although waterflooding is considered a secondary recovery process, high molecular weight polymers are commonly added to the water to increase the viscosity of the water and improve sweep efficiency.

The problems with adding polymers to a waterflood are the high cost of the chemical, low injection rate caused by high viscosity (which impacts economic rate of return), degradation at higher temperatures, intolerance to high salinity, polymer deterioration from shear stress imparted by pumping, flow through tubulars and perforations, and long-term instability in the reservoir environment.

### *Significant Technology Development*

Although waterflooding is not part of the EOR program, work done in chemical EOR can be applied to enhance waterflooding operations. The projects in this section include one focused on water chemistry for optimum waterflood recovery. The other two projects are from the Reservoir Class program and illustrate how an accepted practice applied in a different way can significantly increase oil recovery.

### *Selected Project Summaries*

**Improved Waterflooding Through Brine/Improved Waterflooding by Injection-Brine Modification**
**Contract:** INEEL/EXT-02-01591
**Performers:** Idaho National Engineering and Environmental Laboratory (INEL), University of Wyoming and BP Amoco
**Project Dates:** 1996-2002
**Objectives:** (1) determine the effects of brine composition, temperature, and crude oil properties on wettability and its effects on oil recovery; (2) conduct a field test to verify laboratory results; (3) develop screening criteria that can be used for the selection of suitable field test candidates.
**Results:** Three key conditions were identified that are related to the success of improved waterflooding: (1) the presence of polar components in the crude oil that can adsorb on the rock surfaces, (2) the presence of clay in the rock, and (3) the presence of connate water. Laboratory tests have shown that for sandstone and several crude oils, changes in brine composition can result in differences in waterflood recovery of 15 to 50% of original oil, in place. Waterflood oil recovery comparisons from historical field data from the Powder River Basin support laboratory observations that injection of low-salinity water tends to improve oil recovery during waterflooding.

**Green River Formation Water Flood Demonstration Project -- Class I**
**Contract:** DE-FC22-93BC14958
**Performer:** Inland Resources (formerly Lomax Exploration)
**Project Dates:** 1992-1996
**Objectives:** Evaluate the effectiveness of waterflooding in a low permeability, heterogeneous reservoir with paraffinic oil in Monument Butte field, UT
**Results:** Waterflood was successfully demonstrated and produced 241,768 barrels of incremental oil from project start in 1992 to project end in 1994. The success of this project spurred development of 60 sections and drilling of 740 production wells as of May 2003. Incremental

cumulative production from additional applications the waterflooding technology was 25 million bbl of oil and 70 billion cubic feet of gas by May, 2003.
**Project Publications:** Final report BC14958-15, November 1996

**Enhanced Oil Recovery by Horizontal Waterflooding**
**Contract:** DE-FC26-02NT15452
**Performer:** Grand Resources
**Project Dates:** 2002-2005
**Objectives:** Demonstrate that horizontal waterflooding can be technically and economically effective in the recovery of oil from the 100-year-old Wolco field, Oklahoma
**Results:** Two horizontal producing wells were drilled that were positioned in a high oil saturation zone and a vertical well near the toes of the horizontal wells was converted into an injection well. Oil recovery increased from 8 barrels per day to 15 barrels per day, while water production was dramatically reduced from 700 barrels per day to 135 barrels per day.

## *Simulation and Models*

Significant advances have been made in the resolution and the ability to model complex systems in simulation technology over the last 20 years. However today more types of reservoir measurements are being made at increasingly higher resolutions in more complex reservoirs that all serve to generate orders of magnitude more reservoir data than before.

Greater accuracy in numerical models is required to minimize the risk of reservoir development decisions. These requirements impose huge mathematical and computational challenges, but several key technologies are now available such as the use of massive parallel computing, more accurate physical models, accurate and flexible gridding of the reservoir, fast and robust solvers, and integration with other applications.

### *Process Description and Problems*

Reservoir simulation, or modeling, is one of the most powerful techniques currently available to reservoir engineers. Modeling requires a computer, and compared to most other reservoir calculations, massive amounts of reservoir fluid and petrophysical data. Building a reservoir model requires that the reservoir under study be described by system of cells or gridblocks, the number of which can range from thousands to millions. Each cell must be assigned values for reservoir properties to describe the reservoir. Typically, as fluids are withdrawn or injected into the reservoir at points where wells are located, the computer program simultaneously solves the flow equations that relate how fluid transfer occurs across all of the many block faces within the reservoir model. As the values in each cell changes, corresponding values are calculated for the other blocks in the grid. Changes in fluid saturation and pressure can be tracked across the reservoir over time.

Usually, the simulator is calibrated using historic reservoir pressure and production data in a process referred to as “history matching.” Once the simulator has been successfully calibrated, it is used to predict future reservoir performance under a series of potential scenarios, such as the drilling of new wells or the injection of various fluids.

### *Significant Technology Development*

From 1978 to 1983, most of the simulation research carried out under the EOR Program was on modeling laboratory data from the various EOR methods. From 1983 to 2000, funding shifted to the chemical EOR processes with the development of the UTCHEM simulator by the University of Texas at Austin. In the early 1990s, some funding was directed to develop field simulators for gas injection and especially carbon dioxide injection (MASTER). In 2000, the research was refocused toward improving fluid flow simulators and developing simulators that could help predict mobility control methods for both chemical and gas processes.

From 1978 to 2007, there were 29 projects in simulation, the majority of which was performed by Stanford University, University of Southern California, University of Texas Austin, University of Utah, Idaho National Energy Laboratory, Los Alamos National Laboratory, and NIPER/BDM-Oklahoma. Funding levels for the simulation component of the EOR program are presented in Figure 12.

The major contributions from EOR Program simulation R&D are the reservoir simulators: BOAST (a black oil simulator) UTCHEM (Chemical flooding), MASTER (Miscible Applied Simulation Techniques for Energy Recovery) and several predictive screening models. While these programs were developed in the mid-80's, upgrades have made them usable today. The simulators, predictive models and databases can be accessed at: www.netl.doe.gov/technologies/oil-gas/software/software_main.html.

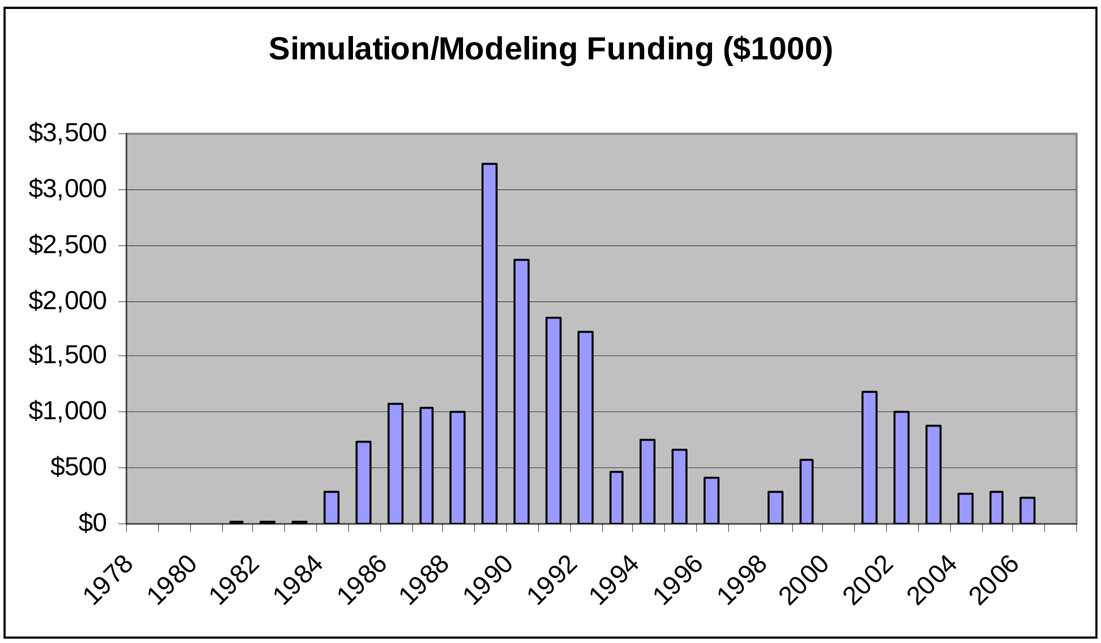


**Figure 12. Funding for simulation and modeling research (FY 1981 thru 2007).**

**BOAST**

Boast is a finite-difference, implicit pressure-explicit saturation (IMPES) three-dimensional numerical simulator that was programmed in Fortran and designed to simulate primary depletion, pressure maintenance by water and/or gas injection, and basic secondary recovery operations in an oil reservoir. It was released in 1982 as the first black oil simulation freeware. At the time, the only other simulators that were available required payment of a substantial fee.

Upgrades to the software included BOAST II, released in 1987 and BOAST III released in 1996, which offered enhanced printing/plotting capabilities. BOAST98, released in 1998, included fluid saturation values corrected by the water-oil contact and gas-oil contact. BOAST-NFR released in 1999 had the ability to simulate horizontal and slant wells with input and output data written in MS EXCEL spreadsheets, and offered a dual-porosity option so that so it could be used to simulate production from fractures. EdBOAST, the final version, offered 32 bit memory. BOAST is still widely used by industry, with an average of 230 copies being downloaded monthly from the NETL webpage as of 2000 (Casteel, 2000).

**UTCHEM**

UTCHEM is a chemical flooding simulator that was developed in the mid-1980s by the University of Texas at Austin. The simulator includes options for predicting the behavior of tracers, polymers, polymer gels, surfactants and alkaline agents injected into oil reservoirs. The simulator can also be used for profile control, tracer tests, formation damage, soil remediation, microbial enhanced oil recovery, surfactant/foam, and wettability alteration. In 2000, more than 60 organizations including more than 20 oil companies were using this simulator. Better management of reservoirs has saved these companies more than $23 million, $8 million of which flowed back to the U.S. Treasury (Casteel, 2000).

**MASTER**

The reservoir simulator MASTER was developed in 1991 by the Morgantown Energy Technology Center to predict the performance of miscible gas injection projects. MASTER is a 3-dimensional, multicomponent simulator that can simultaneously track stock tank oil, natural gas, water, up to four solvent species, and a surfactant. The model uses mixing parameters to account for the density and viscosity changes that occur with the development of a miscible gas displacement. MASTER is intended to approximate results that can be obtained with a fully compositional simulator. The model was developed using the code from the BOAST model.

The major advantage of MASTER was its capability to predict a wide range of reservoir applications, including primary recovery, waterflooding, and miscible gas injection. The model has a switch that allows the miscible gas portion to be turned on or off as required. Thus, it is possible to use the model for history-matching the performance of primary production or a waterflood as well as the performance of miscible gas injection. This capability allows the model to honor the appropriate reservoir description and the fluid saturations that exist at the time a miscible gas project is initiated.

A review of the model's use in 2000 indicated that use of the MASTER simulator by various organizations had been responsible for generating a 3-billion barrel increase in potential reserves (Casteel, 2000).

**$CO_2$ PROPHET**

The $CO_2$ injection prediction software Prophet was conceived by Texaco Exploration and Production Technology Department (EPTD), and was partially developed as part of the DOE Class I cost-share program "Post Waterflood, $CO_2$ Flood in a Light Oil, Fluvial Dominated Deltaic Reservoir" under DOE Contract No. DE-FC22-93BC14960.

**PC-GEL**

PC-Gel is a three-dimensional, three-phase, permeability modification model. The software specifically targets the needs of oil producers who do not have access to costly and complex reservoir simulators.

**Other Tools**

A number of other tools were developed as part of the EOR Program. These include:

**Microbial Transport Simulator (MTS**), a 3D, three-phase, multiple-component numerical model that permits the study of the transport of microorganisms and nutrients in porous media. Microbial parameters incorporated into MTS included microbial growth and decay, microbial deposition, chemotaxis, diffusion, convective dispersion, tumbling, and nutrient consumption.

**Predictive and Screening Models**, easy-to-use tools for quickly and inexpensively estimating the amount of oil that can be recovered from a specific reservoir by an EOR process allowing the calculation of economics and the feasibility of the project. The models for steamflooding, *in situ* combustion, polymer flooding, surfactant flooding and $CO_2$ miscible injection were developed in conjunction with the National Petroleum Council. These EOR screening models were developed by Scientific Software in a joint agreement between DOE and the Ministry of Energy and Mines of the Republic of Venezuela. In 1984, the models were updated to predict performance based on correlations with actual field data.

The accuracy of these models lies between that of simple screening guidelines and the results of an actual reservoir simulator. These predictive tools require minimal amounts of data, are easy to use, and can screen a large number of prospective reservoirs for EOR potential. As of 2000, more than 1000 copies of the model had been distributed to oil field operators, drilling and service companies, consultants, and researchers. The use of these models has been estimated to have saved the industry $400 million by screening out uneconomical projects (Casteel, 2000).

The models are currently available online at (http://www.netl.doe.gov/technologies/oil-gas/Software/Software_main.html).

**NPC Public Database**: (NPCPUBDB.GEO) is a spreadsheet format database developed by the National Petroleum Council (NPC) for its 1984 assessment of the nation's enhanced oil recovery (EOR) potential. The database is available online at (http://www.netl.doe.gov/technologies/oil-gas/Software/database.html#npc).

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Pautz, J. F., C. A. Sellers, C. Nautiyal and E. Allison, 1992, "Enhanced Oil Recovery Project Data Base," April, Publication identification number NIPER-583.

The following EOR-related CDs are available from the National Energy Technology Laboratory:

Basin Oriented Strategies for $CO_2$ Enhanced Oil Recovery (April 2005)

$CO_2$ Solicitation, Brochure, and Project Reports (June 2006)

Heavy Oil Publications, Selected Reports from Heavy Oil Projects (August 2006)

Available from the Library:

U.S. Department of Energy
National Energy Technology Laboratory
Jo Ann Yuill, Library
US/DOE - NETL  MS: B-02
3610 Collins Ferry Road
Morgantown, West Virginia  26505-0880
Library@netl.doe.gov
www.netl.doe.gov
http://www.netl.doe.gov/publications/cdordering

# Appendix A. Summaries of Field Demonstration Projects

## *Cost-Shared EOR Field Demonstration Program*

The oil embargo of the early 1970s prompted the U.S. government to support the application of technologies to increase domestic oil production. EOR methods were emerging as potential technologies to increase oil recovery from fields being produced by primary or secondary methods. A series of 23 cost-shared EOR field demonstration projects were initiated in 1974 to stimulate the application of emerging EOR methods.

During this same time period (1979), the Department of Energy launched a tertiary incentive crude oil program designed to allow producers to offset costs associated with expensive enhanced oil recovery projects by recouping 75% of the front-end money through decontrol of old oil. A producer could recoup up to $20 million through this program. Before the end of that program, applications for certifications to the DOE Energy Regulatory Administration numbered approximately 300. Another primary economic incentive for enhanced recovery projects was the Windfall Profit Tax break for incremental oil production attributable to a qualified tertiary oil recovery project. Certification under the Act entitled an operator to the lowest permissible tax rate of 30%. The certification also accelerated the base level decline, which freed more oil for the lower tax.

Oil company participants included Gulf, Exxon, Conoco, and Shell. Pilot projects employing $CO_2$ injection, polymer-enhanced waterflooding, alkaline waterflooding, surfactant flooding, micellar-polymer flooding and other processes were demonstrated. While many of the demonstrations were technical successes, only a few were technical and economic successes. However, the demonstrations were extremely valuable in identifying problems associated with various EOR methods and guided future EOR R&D for both DOE and the operators.

An EOR Project Data Base was designed in 1981 that contained data from the cost-shared projects in the 1976 EOR field demonstration, 433 Tertiary Incentive projects (tax credit for implementing EOR), and data compiled by the Gulf Universities Research Consortium (GURC) in 1978 on 173 EOR projects (Pautz, et al, 1992). General project information was included in the database as well as rock and fluid characteristics of the reservoirs, the types and amounts of injectants, the size of the project area and number of wells, a success rating and any other information available. By 1992, the data base contained information on 1,388 EOR projects in 569 different oil fields recording projects as old as 1949 (Pautz et al., 1992). Projects from literature searches resulted in the addition of 768 projects.

Although the original project reports are not available, post-project evaluations were performed by Keplinger and Associates. Report ID numbers for the evaluation reports are listed in Table 1. The database lists 10 post-project evaluation reports (Table 1). The reports marked by an asterisk are available on the CD accompanying this report.

**Table 1. Reports evaluating DOE cost-shared EOR projects.**

| Publication Date | Report Title | Industry Partner | Evaluation Publication ID |
|---|---|---|---|
| 01-Apr-86 | Evaluation of the Little Knife $CO_2$ Minitest | Gulf Oil Corp. | DOE/BC/10830-3* |
| 01-Nov-88 | A Review of the West Sussex Unit $CO_2$ Flood Project | Conoco, Inc. | DOE/BC/10830-7* |
| 01-Feb-89 | An Evaluation of the $CO_2$ Pilot Maljamar Field Lea County, New Mexico | Conoco | DOE/BC/10830-12* |
| 01-Feb-89 | An Evaluation of the Weeks Island "S" Sand Reservoir B Gravity Stable $CO_2$ Displacement Project Iberia Parish, Louisiana | Shell Oil Company | DOE/BC/10830-11* |
| 01-Oct-82 | Evaluation of the Bodcau (Bellevue) In Situ Combustion Project | Cities Service Oil Company | DOE/BC/10033-4* |
| 1-Oct-82 | An Evaluation of the Bell Creek Field Micellar-Polymer Pilot | Gary Energy Corporation | DOE/BC/10033-5* |
| 1-Oct-84 | Project Evaluation: Penn Grade Micellar Displacement Project | Pennzoil Company | DOE/BC/10033-10* |
| 01-Dec-87 | Evaluation of Micellar-Polymer Flood Projects in a Highly Saline Environment in the El Dorado Field | Cities Service | DOE/BC/10830-6* |
| 01-Nov-88 | A Review of the Loudon Surfactant Flood Pilot Test | Exxon | DOE/BC/10830-8* |
| 0-May-87 | An Evaluation of the Alkaline Waterflooding Demonstration Project, Ranger Zone Wilmington Field, California | THUMS/ City of Long Beach | DOE/BC/10830-5* |
| Oct-83 | An Evaluation of the Wilmington Field Micellar Polymer Project | City of Long Beach | DOE/BC10033-8* |
| 01-Dec-88 | An Evaluation of the Big Muddy Field Low-Tension Flood Demonstration Project | Conoco | DOE/BC/10830-9 |
| 01-Mar-86 | Evaluation of the Storms Pool Improved Waterflood Project | Energy Resources Co. | DOE/BC/10830-1* |
| Apr-83 | Evaluation of the Coalinga Polymer Demonstration | Shell Oil | DOE/BC/10033-7* |
| Aug-82 | An Evaluation of the North Burbank Unit Tertiary Recovery Pilot Test | Phillips Petroleum | DOE/BC/10033-2* |
| 01-Nov-86 | A Review and Statistical Analysis of Micellar-Polymer Field Test Data | Keplinger Technology Consultants | DOE/BC/10830-4* |

## *$CO_2$ Injection Projects*

**Evaluation of the Little Knife $CO_2$ Minitest**
**Contract:** NA
**Performer:** Gulf Oil Corporation
**Project Dates:** NA
Location: Little Knife Field, North Dakota
Objectives: Determine the commercialization potential of $CO_2$ miscible displacement in dolomitized carbonate oil reservoirs that have high remaining oil saturations in a 4-spot, nonproducing minitest.
**Results:** The minitest was a technical success. Simulation studies using the data collected from the minitest predicted an economically favorable cost per barrel. Although a nonproducing minitest using a logging-observation well reduced the time and expense, the absence of production data reduced the ability to estimate oil recovery, volumetrics and reservoir heterogeneity.
**Project Evaluation Report:** DOE/MC/08383-45

**A Review of the West Sussex Unit $CO_2$ Flood Project**
**Contract:** NA
**Performer:** Conoco, Inc
**Project Dates:** 1982 - 1983
**Location:** West Sussex Field, WY
**Objectives:** Determine whether $CO_2$ injection can recover economic quantities of oil in the West Sussex field.
**Results:** The operators considered the pilot successful and potentially economic if expanded. The pilot recovered 16,000 bbl of incremental oil representing 7.8% OOIP. However, the oil recovery may have been due to the water injected with the $CO_2$ rather than a response to miscible $CO_2$ injection.
**Project publication:** Hoiland, *et al.*, 1986 "Case History of a Successful Rocky Mountain Pilot $CO_2$ Flood", SPE/DOE 14939, presented at the Fifth Symposium on Enhanced Oil Recovery or the Society of Engineers, Tulsa, OK April 20-23, 1986.
Project Evaluation Report: "Review of West Sussex Unit $CO_2$ Flood Project" DOE/BC/10830-7*

**An Evaluation of the $CO_2$ Pilot Maljamar Field, Lea County, New Mexico**
**Contract:** NA
**Performer:** Conoco Oil Company
**Project Dates:** 1981 - 1986
**Location:** Maljamar Field, Lea County, New Mexico
**Objectives:** Provide data for computer modeling of the reservoir and for facilities design and economic analysis of a full scale project.
**Results:** The success of this pilot spurred field wide expansion of $CO_2$ injection in the Maljamar field. The pilot experienced problems with corrosion, well tests and oil handling. The solutions found to these problems were valuable to the design of the full-scale operation.
**Project publications:**
Albright, J.C., 1986, "Use of Well Logs to Characterize Fluid Flow in the Maljamar Pilot," Journal of Petroleum Technology, August, pp. 883-890
Moore, J.S. and Clark, G.C., 1988, "History Match of the Maljamar $CO_2$ Pilot Performance," SPE/DOE paper 17323, presented at the SPE/DOE Enhanced Oil Recovery Symposium, Tulsa, Oklahoma, April 17-20.
Pittaway, K.R., *et al.*, 1985, "Development and Status of the Maljamar $CO_2$ Pilot," Journal of Petroleum Technology, March, pp.537-544.

Pittaway, K.R., *et al*, 1987, "The Maljamar $CO_2$ Pilot: Review and Results," Journal of Petroleum Technology, October, pp. 1256-1260.
**Project Evaluation Report:** DOE/BC/10830-12*

**An Evaluation of the Weeks Island "S" Sand Reservoir B Gravity Stable $CO_2$ displacement Project, Iberia Parish, Louisiana**
**Contract:** NA
**Performer:** Shell Oil Company
**Project Dates:** 1978 - 1982
**Location:** Weeks Island Field, Iberia Parish, Louisiana.
**Objectives:** Demonstrate that a gravity stable $CO_2$ process can recover significant amounts of oil after waterflooding in high permeability, steeply dipping reservoirs.
**Results:** The pilot successfully recovered 261,500 bbls oil showing that the gravity stable $CO_2$ displacement process was highly efficient in the Weeks Island Sand Reservoirs. However, further economic evaluation showed that gravity stable displacement by gas cap expansion, although recovering slightly less oil, is more economically attractive than the gravity stable $CO_2$ displacement process. For either process to be economically attractive, the displacement must be implemented early in the field life in lieu of waterflooding.
Project publications:
Johnston, J.R., 1988, "Weeks Island Gravity Stable CO2 Pilot," SPE/DOE paper 17351, presented at the Sixth Enhanced Oil Recovery Symposium, Tulsa, Oklahoma, April 17-20, 1988.
Perry, G.E., *et al*, 1982, "Weeks Island 'S' Sand Reservoir B Gravity Stable Miscible CO2 Displacement, Iberia Parish, Louisiana," SPE/DOE paper 10695 presented at the Third Joint Symposium on Enhanced Oil Recovery, Tulsa, Oklahoma, April 4-7.
**Project Evaluation Report:** DOE/BC/10830-11

## *Chemical Flooding Projects*

**A Review and Statistical Analysis of Micellar-Polymer Field Test Data**
**Contract:** DE-AC19-85BC10830
**Performer:** Keplinger Technology Consultants, Inc.
**Project Date:** 1986
**Objectives:** Identify variables limiting oil recovery from micellar-polymer processes in 21 field tests using statistical methods
**Results:** Three significant correlations were found: (1) oil recovery is inversely related to connate water salinity; (2) oil recovery increased as the project size decreased; and (3) oil recovery is related to the quantity of surfactant used.
**Project Evaluation Report:** DOE/BC/10833-4

**A Review of the Loudon Surfactant Flood Pilot Test**
**Contract:** NA
**Performer:** Exxon
**Project Date:** 1981
**Location:** Loudon Field, IL
**Objectives:** Demonstrate that the surfactant flood process can economically recover oil from a low pressure, shallow reservoir.
**Results:** About 60% of the residual oil saturation was recovered within the pattern area. The carefully designed chemical system tailored for the formation water salinity and hardness was a key to the success of this pilot. Two main problems emerged during the project: (1) emulsion

problems after the surfactant reached the production well, and (2) bacterial degradation of the polymer. Project demonstrated the need for a better understanding of the many complex and interrelated factors which influence the degradation of biopolymers.
Project Publication:
Bragg, *et al,* 1982, "Loudon Surfactant Flood Pilot Test," SPE/DOE paper 10862, presented at the 1982 SPE/DOE Joint Symposium on Enhanced Oil Recovery, Tulsa, OK, April 4-7.
**Project Evaluation Report:** DOE/BC/10830-8

## *Enhanced Waterflood Projects*

**Evaluation of the Storms Pool Improved Waterflood Project**
**Contract:** DE-AC01-78ET12065
**Performer:** Energy Resources Company, Inc. (ERCO)
**Project Date:** 1977-1982
**Location:** Storms Pool field, Illinois
**Objectives:** Evaluate the technical efficiency and economic feasibility of polymer-enhanced waterflooding as a tertiary recovery process in a heterogeneous sandstone reservoir that had been successfully waterflooded.
**Results:** Insignificant amounts of oil were produced during the 100-acre polymer-enhanced waterflood. The poor response was attributed to the lower than anticipated oil saturation left after waterflooding and the degradation of the polymer. Recommendations for future projects are to: (1) obtain reservoir information to ascertain the suitability of the reservoir for the process planned; (2) use polymers and procedures that are optimum for the field; and (3) incorporate a program for collecting reservoir data and evaluating performance.
**Project evaluation report:** DOE/ET/12065-66

**An Evaluation of the Big Muddy Field Low-Tension Flood Demonstration Project**
**Contract:** NA
**Performer:** Conoco
**Project Date:** NA
**Location:** Big Muddy field Wyoming
**Objectives:** Evaluate the technical efficiency and economic feasibility of a commercial scale low-tension flood (micellar-polymer) demonstration project conducted in the Second Wall Creek Reservoir in the Big Muddy field in east central Wyoming.
**Results:** The low-tension process successfully mobilized waterflood residual oil, however oil recovery was significantly less than originally predicted. Factors behind the low recovery included: (1) lack of containment of the injected fluids in the reservoir; (2) behind-pipe communication in abandoned or reconditioned wellbores allowed fluid to migrate away from the reservoir; and (3) fluid entry from other reservoirs occurred concurrently with migration of the fluids from the reservoir. Fluid containment deteriorated significantly when injection pressures during the polymer injection period were allowed to exceed the formation parting pressure. Injectivity in the relatively low permeability reservoir was a continuing operational problem.
**Project Evaluation Report:** DOE/BC/10830-9

## *Reservoir Class Field Demonstration Program Projects*

The Reservoir Class Field Demonstration program, started in 1991, was based on the importance of geology in controlling the aerial distribution of porosity and permeability, and the belief that facies geometry defined, to a large part, fluid flow in a reservoir. Reservoir characterization was a major element in the Class projects. The program was based on the "play" concept and the thesis that reservoirs of similar depositional environments will have similar reservoir properties and thus will present similar challenges to enhanced recovery of residual oil. Three Reservoir Class solicitations addressed each of three depositional environment types: fluvially-dominated deltaic reservoirs, shallow-shelf carbonate reservoirs, and marine shelf and basin sandstone reservoirs. A fourth solicitation, Class Revisit, selected 10 new projects in the three depositional classes. The projects listed below focused on using state-of-the-art diagnostic and imaging technologies to determine the best approaches for subsequent application of EOR. Each project consisted of two phases: Phase 1 entailed reservoir characterization of the demonstration reservoir and process design. In Phase II, the field demonstration was implemented. The Class Revisit projects added a third phase – monitoring.

**Goals and Objectives of the Program**

The stated goals of the Class Program were to:

- Extend the economic production of domestic fields by slowing the rate of well abandonments and preserving industry infrastructure (including facilities, wells, operating units, data, and expertise).
- Increase ultimate recovery in known fields by demonstrating better methods of reservoir characterization (both rock and fluid), advanced oil recovery and production technologies, advanced environmental compliance technologies, and improved reservoir management techniques.
- Use field demonstrations to broaden information exchange and technology application among stakeholders by expanding participation in DOE projects to include both traditional and nontraditional participants, and by increasing third-party participation and interaction throughout the life of DOE-sponsored projects.
- Integrate field demonstration activities with activities of other areas of the advanced oil recovery program by actively pursuing demonstration activities from work developed in other program areas, assessing field demonstration efforts regarding future directions and research needs, and informing the research community of research needs and opportunities identified in demonstration projects.

Out of 39 projects conducted in the Class program, the following 23 projects applied an EOR process. Prior to 2003 annual and final reports were published and distributed. After May 2003 submitted reports were sent to OSTI, but not published.

### *Gas Injection*

**West Hackberry Tertiary Project -- Class I**
**Contract**: DE-FC22-93C14963
**Performer**: Amoco Exploration and Production Co.
**Project Dates**: 9/3/1993 to 7/2/2002
**Oligocene Hackberry Formation –** West Hackberry Field (8,000 ft.), Cameron Parish, Louisiana, Mississippi Salt Basin
**Objectives**: Field test the concept that air injection can be combined with the double displacement process (gas displacement of a water-invaded oil column to generate tertiary oil

recovery through gravity drainage) to create a new EOR process for light oil reservoirs that would be profitable. Although other gasses such as nitrogen or carbon dioxide can be combined with the double displacement process, air is lower cost and universally accessible, even in remote or environmentally sensitive areas.
**Results**: The project design called for air injection into the high-pressure West Flank reservoir at West Hackberry field, Louisiana. Air injection coupled with gravity drainage was determined to be the best method to recovery the 30-40% of oil left after normal waterflood recovery. By July 1999, 50% of the planned air volume had been injected in the West Flank reservoir. The reservoir pressure has risen by 500 psi, but the reservoir had not responded as expected. Analysis determined that the oil-water contact had not moved sufficiently down structure to reach the producing wells.

In 1996 the project was expanded to include the North Flank of West Hackberry field. Three North Flank reservoirs were put under air injection and showed a positive response within two months. Between July 1996 and July 1999 the North Flank reservoirs had produced 224,000 barrels of incremental oil. The success of the North Flank reservoirs is attributed to the ability of the air injection and double displacement gravity flow process to work effectively in low-pressure reservoirs. In the low-pressure reservoir the process was able to push the oil-water contact down structure sufficiently to make contact with the producing wells. As of July 1999, when BP/Amoco sold West Hackberry field, the North Flank reservoirs were producing 270 barrels of incremental oil per day.

The Amoco project was moderately successful in increasing incremental production. When British Petroleum took over Amoco in 1997, a two year extension of Phase I was requested. When the extension was up BP Amoco decided that they did not wish to commit themselves to the research and implementation of Phase II; and agreed to terminate the project, and to submit a final report.
**Project publication**: The final report, BC14963-21, 2000.

**Improved Miscible Nitrogen Flood Performance Utilizing Advanced Reservoir Characterization & Horizontal Laterals in a Class I Reservoir - East Binger (Marchand) Unit/Class Revisits**
**Contract**: DE-AC26-00BC15121
**Performer**: Binger Operations
**Project Dates**: 4/11/2000 to 4/10/2005
**Upper Pennsylvanian Upper Marchand Sand (Hoxbar Group) Fm. –** East Binger Unit (9,900 to 10,010 ft.), Caddo Co., OK, Anadarko Basin
**Objectives**: Demonstrate use of nitrogen as a widely available, cost-effective and environmentally superior injectant for miscible floods, and demonstrate the effectiveness of horizontal wellbores in reducing gas breakthrough and cycling.
**Results**: Through the process of evaluating the benefits of horizontal wells in the East Binger Unit, Marchand sand reservoir, a greater understanding of the reservoir flow mechanisms was obtained, allowing further development and improved recovery for the field. This geologic and reservoir setting, combined with the recovery mechanism employed, proved to be more appropriate for vertical wells. Based on results achieved, additional drilling beyond the scope of the original project has been completed.

Binger Operations drilled and completed three horizontal and seven vertical wells, converted five producer wells to injectors, completed modeling and fluid flow characterization work to identify critical fluid flow mechanisms, and evaluated over 200 gas samples to monitor gas cycling and the effects of producer-to-injector conversions.

Three horizontal wells were drilled into the Pennsylvanian Hoxbar formation of the Eastern Anadarko Basin, where previously only one such well had been drilled. Drilling difficulties were encountered and overcome. Although these technologies were not proven to be the most cost-effective for this field—in large part due to the recovery mechanism employed—they very likely will be the most cost-effective drilling technique in similar reservoirs with different recovery mechanisms. Project development work has added 200-300 barrels of oil per day to field production, roughly doubling production in the project area.
**Project publication(s)**: Final report submitted in 2005.

## *$CO_2$ Flooding*

**Post Waterflood $CO_2$ Miscible Flood in Light Oil Fluvial-Dominated Deltaic Reservoirs -- Class I**
**Contract**: DE-FC22-93BC14960
**Performer**: Texaco E&P
**Project Dates**: 6/1/1993 to 12/31/1997
**Oligocene Frio Formation –** Port Neches Field (5,900 ft.), Orange Co., TX, East Texas Basin
**Objectives:** The objectives of the project were to analyze the use of $CO_2$ miscible flooding by horizontal gas injection into a watered-out salt dome reservoir and to transfer the technologies developed to operators of similar light oil reservoirs.
**Results**: The scope of work in Phase I was to conduct reservoir characterization and develop software models for an improved method for screening candidate reservoirs for $CO_2$ flooding, and huff-n-flood technologies. A screening model was used with 3-D seismic to select sites for horizontal injection wells in Port Neches field, and was used to screen data from 197 fields in Louisiana for $CO_2$ flood potential. The water alternating gas (WAG) process was used and proved to be effective in mobility control in highly permeable sands. The technology used for miscible $CO_2$ flooding was technically successfully, but Texaco did not feel that it increased production or revenues sufficiently to continue the process due to constraints in the Port Neches field. There were mechanical problems relating to drilling the horizontal injection well, premature $CO_2$ breakthrough, and size limits in the production unit. Texaco did not continue the project to Phase II. The project ended in December 1997.
**Project publication (s)**: Final report BC14960-19 published in 2002.

**Applications of Advanced Petroleum Production Technology and Water Alternating Gas Injection - Class I**
**Contract**: DE-FC22-93BC14955
**Performer**: American Oil Recovery
**Project Dates**: 1/1/1993 to 3/31/1995
**Mississippian Cypress Sandstone –** Mattoon Field (1,800 ft.), Coles Co., Illinois, Illinois Basin
**Objectives**: (1) Characterize the Cypress Sandstone and design and implement water-alternating-gas (WAG) injection using carbon dioxide; (2) develop a numerical model to select test sites for the demonstrations; (3) Compare WAG to waterflooding and cyclic gas injection in different parts of the reservoir.
**Results**: The reservoir geology was completed including detailed stratigraphic cross sections, structure maps, isopach maps, lithofacies maps and 3-D reservoir computer model using STRATAMODEL software. Five distinct facies defined waterflood sub-units (FDWS) were identified and injectivity tests using carbon dioxide were conducted. The simulator was used to verify and enhance reservoir characterization work and aid in the site selection and design of the WAG scheduled for Phase II. Laboratory testing such as produced gas analysis and oil PVT tests

were conducted. The site for an infill well/core hole was selected based upon the results of reservoir geology and injectivity tests. The project terminated at the end of Phase I.
**Project publication(s)**: Annual report BC14955-8, 1995.

**CO2 Huff-n-Puff Process in Light Oil Shallow Shelf Carbonate Reservoir (Central Vacuum Unit), Vacuum Field, Lea County, New Mexico -- Class II**
**Contract**: DE-FC22-93BC14986
**Performer**: Texaco E&P
**Project Dates**: 2/10/1994 to 12/31/1997
**Permian San Andres/Grayburg Fm. –** Central Vacuum Field (4,550 ft.), Lea Co., NM and Slaughter Field, Hockley Co., TX, Permian Basin
**Objectives**:(1) Determine the feasibility and practicality of applying $CO_2$ huff-n-puff technology in the Vacuum Unit (CVU) and Sundown Slaughter Unit (SSU); (2) Use the results of parametric simulation of the $CO_2$ huff-n-puff process coupled with the CVU reservoir characterization components to determine if this process is technically and economically feasible for field implementation; (3) Disseminate the knowledge gained in support of the DOE objective of increasing domestic oil production and deferring the abandonment of shallow shelf carbonate (SSC) reservoirs.
**Results:** A 4-Dimensional, 3-Component seismic survey was conducted to dynamically monitor saturation changes and frontal movement associated with the $CO_2$ injectant. Evaluation and history matching with compositional simulation of the Central Vacuum field was completed. Due to the lack of trapped gas in the near-wellbore vicinity, approximately 100% of the injected $CO_2$ was expected to be recovered, suggesting the process was not well suited to the Central Vacuum reservoir. The analysis of the Central Vacuum site suggested that the process was not an economic alternative within waterflooded shallow shelf carbonate reservoirs. The addition of a new site (Sundown Slaughter Unit of Slaughter Field) was used to evaluate findings from the first demonstration. Following the project, technologies used in this field demonstration were successfully applied in a nearby carbonate reservoir. The huff-n-puff process was not successful in either field; however, the final report for the project provided a good "Lessons Learned" evaluation of how to operate a huff-n-puff process, and the field criteria necessary prior to implementation. Results in 2000-2002 suggest there may be some long term response in production as the result of the project.
**Project publication(s)**: Final report BC14986-14, 1999.

**Increased Oil Production and Reserves Utilizing Secondary/Tertiary Recovery Techniques on Small Reservoirs in the Paradox Basin, Utah -- Class II**
**Contract**: DE-FC22-93BC14988
**Performer**: Utah Geological Survey
**Project Dates**: 2/9/1995 to 8/31/2005
**Pennsylvanian Paradox Formation –** Anasazi, Runway, Blue Hogan, Mule, and Heron North fields (5,700 ft.), San Juan County, UT and Navajo Nation, Paradox Basin
**Objectives**: (1) Increase production and reserves from the shallow shelf carbonate reservoir in the Paradox Basin of Utah and Colorado through geological and engineering investigations, leading to the application of advanced secondary recovery technology; and (2) conduct technical studies on five diverse small fields located within the Navajo Nation to select the best candidate field for a pilot demonstration.
**Results**: Total additional Paradox Basin potential was estimated to be more than 200 million bbl of oil. The establishment of the general facies belts and stratigraphic patterns within the shallow-shelf carbonate Desert Creek zone of the Paradox Formation led to a better understanding of reservoir heterogeneity and capacity of the five fields being evaluated for the pilot demonstration,

and a greater level of predictability of petroleum potential for exploration targets. Outcrops of the Paradox Formation Ismay zone along the San Juan River provided small-scale analogues of reservoir heterogeneity, flow barriers and baffles, lithofacies, and geometry. These analogues were used in reservoir simulation models for secondary/tertiary recovery of oil from small fields in the basin. No previous waterfloods, $CO_2$ floods, detailed study of reservoir heterogeneities, or reservoir simulations had been conducted on such small, one-to-three well fields in the Paradox Basin.

After completion of the study of waterflood and $CO_2$ potential for these Paradox Basin small carbonate fields, continuous $CO_2$ injection without gas processing was recommended for the algal mounds. Reservoir modeling used 20 geostatistical models to predict $CO_2$ flood performance history; matches were made by tying to previous production and reservoir pressure history so that future reservoir performance could be predicted. Engineering analysis and reservoir simulation of Anasazi and Runway fields was completed in June 1998. The Anasazi field was selected and approved for the Phase II $CO_2$ flood based on the reservoir evaluation and geostatistical modeling, which predicted an economic return with payout in 35 months.

The project was delayed for two years under no-cost extensions while attempting to establish a $CO_2$ source. Texaco's planned pipeline was delayed due to low oil prices in 1998-99, and when it was finally completed the Greater Aneth field took the entire capacity. The original operator, Harken Energy, was sold and the new company declined to continue the search for a $CO_2$ source. The project terminated in 2002 without entering Budget Period II.
**Project publication(s)**: Final report, December 2002.

**Application of Reservoir Characterization and Advanced Technology Improves Recovery and Economics in Lower Quality Shallow Shelf San Andres Reservoirs -- Class II**
**Contract:** DE-FC22-93BC14990
**Performer**: OXY USA
**Project Dates**: 8/3/1994 to 9/3/2002
**Permian San Andres Formation –** West Welch Field (4,800 ft.), Dawson Co., TX, Permian Basin
**Objectives**: Demonstrate the application of cross wellbore tomography, hydraulic fracture orientation detection, 3-D seismic methods, and cyclic $CO_2$ stimulation to improve the economics of conventional $CO_2$ flooding.
**Results**: 3-D Seismic integration was used to map reserves with an estimated 300,000 bbls of additional reserves for the West Welch Unit. Evaluation of seismic responses led to the development of a statistical relationship between pore volume and seismic attributes. Five new wells showed that seismically guided mapping was an accurate substitute for porosity mapping. Pressure bombs run in the injection well measuring $CO_2$ bottom hole injection pressure determined that the appropriate $CO_2$ surface pressure for optimal $CO_2$ injection increased the $CO_2$ injection rate by approximately 20%. Ten well workovers were done to enhance wellbore conditions. Positive results have been realized, but not in all wells. Efforts to improve performance in other wells used stimulation through lift revisions and optimization of the pump-off controllers. A horizontal well was drilled in December 2000 for the purpose of capturing poorly swept oil zones from a 7-spot pattern. The horizontal well was drilled to length of 3,000 ft. and hydraulically fractured, which increased production 10-fold. $CO_2$ injection was terminated at West Welch field in April 2002 due to poor economic response after five years. Injection was not sufficiently cost-effective to continue or expand the $CO_2$ process.
**Project publication(s)**: The final report BC14989-23 was published in March 2000.

**Design and implementation of a $CO_2$ Flood Utilizing Advanced Reservoir Characterization and Horizontal Injection Wells in a Shallow Shelf Carbonate Approaching Waterflood Depletion -- Class II**
**Contract**: DE-FC22-93BC14991
**Performer:** Phillips Petroleum
**Project Dates**: 6/30/1994 to 9/2/2002
**Permian Grayburg/San Andres Fm. –** South Cowden Field (4,450 ft.), Ector Co., TX, Permian Basin
**Objectives**: (1) Demonstrate the economic viability and widespread applicability of an innovative reservoir management and approach for improving $CO_2$ flood project economics in shallow shelf carbonate reservoirs; (2) reduce the number and cost of new injection wells, wellheads, and equipment; (3) concentrate the surface reinjection facilities; and minimize the cost associated with the $CO_2$ distribution system.
**Results**: Successful application of the horizontal drilling and $CO_2$ flood optimization techniques developed demonstrated economic benefits. The techniques applied could potentially recover an additional 3 million bbl of oil from the unit. Application to other Permian Basin carbonate reservoirs could recover up to 1 billion bbl. Using one-third the number of injectors previously required and improvements in $CO_2$ sweep efficiency using horizontal injection wells resulted in over 25% reduction in capital and drilling costs. New injection wells were completed in 1996-97, and 2 horizontal and 3 vertical wells were drilled in 1997-98. An additional 16 wells were converted or reactivated. Two surfactants identified improved $CO_2$ foam mobility and diversion. The average production increase at the South Cowden demonstration was 200 BOPD. The average rate of productivity increase for seven wells was 92%. Total incremental production after twenty months of $CO_2$ injection was 448 BOPD. Cumulative incremental production was 500,000 bbl at the end of the project in September 2002.
**Project publication(s)**: The final report BC14991-23 in November 2002.

**Application of Advanced Reservoir Characterization, Simulation and Production Optimization Strategies to Maximize Recovery in Slope and Basin Clastic Reservoirs, West Texas (Delaware Basin) -- Class III**
**Contract**: DE-FC22-95BC14936
**Performer**: Bureau of Economic Geology, University of Texas, Austin
**Project Dates**: 3/31/1995 to 8/31/2001
**Permian Bell Canyon Formation and Ramsey Sandstone –** East Ford and Geraldine Ford Fields (2,700 ft.), Reeves & Culbertson Counties, TX, Delaware Basin
**Objectives**: Demonstrate that detailed reservoir characterization is a cost-effective way to recover a higher percentage of the original oil in place through strategic placement of infill wells and geologically based field development.
**Results**: Slope and basin clastic reservoirs in the sandstones of the Delaware Mountain Group in the Delaware Basin (the western subbasin of the Permian Basin) of West Texas and New Mexico contained more than 1.8 billion bbl of original oil at discovery. Recovery efficiencies of these reservoirs have been considerably lower than that of the national average. Thus, a substantial amount of the original oil in place still remains in these reservoirs. The immediate target for the project was the 16.9 million bbl of remaining oil in place in the East Ford field. Budget Period I was conducted in Ford Geraldine and West Ford fields with Conoco as the operator. An extension of Budget Period I transferred the project to East Ford Field with Orla Petco as the field operator. This project demonstrated that (1) enhanced oil recovery by $CO_2$ flood can increase production from slope and basin clastic reservoirs of the Delaware Mountain Group, and (2) reservoir characterization can improve EOR projects in general. $CO_2$ injection in the East Ford unit began in July 1995. As a result of the $CO_2$ flood, production has increased from 30 BOPD at the end of primary production to more than 185 BOPD in 2001.

The East Ford unit produced 180,097 bbl of oil from the start of tertiary recovery through May 2001; essentially all production can be attributed to the enhanced oil recovery project.

Application of project technology to East Ford field resulted in 1.7 MMbbl of incremental oil recovery. Of the 12.2 MMbbl of remaining oil in place in the East Ford demonstration area, an estimated 1.2 to 3.7 MMbbl will be ultimately recoverable through $CO_2$ flood. Technology transfer will benefit development of other Delaware Reservoirs, which contain 1,558 MMBO of remaining oil.
**Project publication(s)**: The final report BC14936-18 was published in November 2001.

**Advanced Reservoir Characterization in the Antelope Shale to Establish the Viability of $CO_2$-Enhanced Oil Recovery in California's Monterey Fm. Siliceous Shales -- Class III**
**Contract**: DE-FC22-95BC14938
**Performer**: Chevron
**Project Dates**: 2/12/1996 to 2/28/2003
**Miocene Monterey Formation (Antelope Shale) –** Buena Vista Hills Field (4,4450 ft.), Kern Co., CA, San Joaquin Basin
**Miocene Monterey Formation (Belridge Diatomite) –** Lost Hills Field (1,300 ft.), Kern Co., CA, San Joaquin Basin
**Objectives**: Increase oil recovery from the Monterey/Antelope Siliceous Shale through the application of an innovative reservoir management plan.
**Results**: The original goal was to increase oil recovery from the Monterey/Antelope Siliceous Shale through the application of an innovative reservoir management plan and $CO_2$ flooding. The Buena Vista Hills reservoir discovered in 1952 produced only 9 million bbl of oil by 1994, representing 6.5% of the estimated 130 million bbl of original-oil-in-place. Production from wells in this field, and in the Antelope Shale in general, has been declining, and the wells were in danger of being abandoned. However, based on the reservoir characterization of the Buena Vista Hills field carried out during Phase 1, the Antelope shale was deemed unsuitable for a $CO_2$ flood. Phase II was transferred to an 8-acre site in Lost Hills field for the pilot $CO_2$ flood demonstration. The Lost Hills Belridge diatomite is a unique reservoir and its unusual properties such as extremely small pore size, high porosity and low permeability have historically led to low primary oil recovery (3-4% OOIP). Due to the low primary recovery and large amount of remaining oil in place, Lost Hills presented an attractive target for EOR.

Remediation programs were developed and implemented throughout 2001 and 2002. Sanding became severe and caused a major blowout in the casing in one well. Tracer and salinity surveys suggested that the producers and injectors were directly connected. Simulation showed that higher flow channels in the reservoir were having an adverse affect on the performance of the pilot. It appeared that $CO_2$ was capable of increasing oil recovery from diatomite, however in the Lost Hills pilot the $CO_2$ followed the "path of least resistance" and bypassed matrix oil. $CO_2$ predominantly flowed through induced hydraulic fractures and faults, and the channels through a very small part of the reservoir carryed sand at high velocity. The sand-laden $CO_2$ found holes formed by subsidence-related well failures and exacerbated the sanding problems. After an evaluation of the problems, $CO_2$ injection was terminated on January 30, 2003.
**Project publication (s)**: The final report BC14938 was submitted June 2003.

**Advanced Reservoir Characterization and Evaluation of $CO_2$-Gravity Drainage in the Naturally Fractured Spraberry Reservoir -- Class III**
**Contract**: DE-FC22-95BC14942
**Performer**: Pioneer Natural Resources (formerly Parker and Parsley)
**Project Dates**: 7/24/1995 to 7/23/2002

**Permian Spraberry Formation (Spraberry Trend) –** E. T. O'Daniel Field (6,800 ft.), Midland Co., TX, Permian Basin
**Objectives**: Determine the technical and economic feasibility of continuous CO2 injection in the naturally fractured reservoirs of the Spraberry Trend.
**Results**: Waterflooding was initiated in the Spraberry in the 1950s, but recovery of oil from this process was relatively poor and only marginally economic. Ultimate recovery under current operations for the Spraberry is extremely low, no greater than 12% of the original oil in place. Because the Spraberry is a fractured reservoir, "conventional wisdom" implied that oil recovery could not be substantially improved by $CO_2$ flooding. The project tested the hypotheses that when $CO_2$ is injected under near-miscible conditions, significant amounts of oil previously unaffected by water injection can be drained by a gravity mechanism from the rock pores into the fractures and moved to producing wells.

$CO_2$ gravity drainage experiments in Spraberry and Berea whole cores at reservoir conditions validated the premise that $CO_2$ could recover oil from the tight, unconfined Spraberry matrix. Injection tests indicated that the pilot needed to be waterflooded prior to $CO_2$ flooding to obtain the necessary reservoir pressure, and waterflooding began in 1999. A line drive waterflood was implemented rather than the typical west Texas five spot flood pattern. The waterflood aligned with the Spraberry fracture pattern with spectacular results. Due to the surprising waterflood response and the distance from injection wells to responding wells, the initial pilot area was expanded from 60 acres to 1,200 acres. Because of the success of the new waterflooding techniques, plans to implement the $CO_2$ flood were put on hold and Pioneer expanded the waterflood technology to numerous other leases in the Spraberry Trend, buying acerage and drilling new wells.

Oil recovery had reached 18% of OOIP by 2001, arresting the decline in production. The pilot produced 150,000 bbl of incremental oil from four wells. Indivdual wells went from 10-15 BOPD (average over 10 years) prior to waterflooding to 90 BOPD and sustained proudction of 80 BOPD per well through September 2003. A followup project was awarded under the PUMP program to Texas A&M to fully understand the process and the success of the waterflooding.
**Project publications)**: The final report BC14942-15 was published in July 2002.

**Field Demonstration of Carbon Dioxide Miscible Flooding in the Lansing-Kansas City Formation, Central Kansas/Class Revisit**
**Contract**: DE-FC26-00BC15124
**Performer**: University of Kansas
**Project Dates**: 3/8/2000 to 3/7/2010
**Upper Pennsylvanian Lansing-Kansas City Formation –** Hall-Gurney Field (2,985 ft.), Russell Co., KS, Central Kansas Uplift
**Objectives**: (1) Demonstrate the viability of $CO_2$ miscible flooding in the Lansing-Kansas City formation on the Central Kansas Uplift; (2) obtain data concerning reservoir properties, flood performance, and operating costs and methods to aid operators in future floods; (3) perform a $CO_2$ miscible flood in a 40-acre pilot in a representative oomoldic limestone reservoir in the Hall-Gurney Field, Russell County, Kansas; (4) characterize the reservoir geologic and engineering properties, model the flood using reservoir simulation; (5) design and construct facilities and remediate existing wells, implement the planned flood, and monitor the flood process; and (6) disseminate the results of this project through various technology transfer activities.
**Results**: There were no miscible $CO_2$ floods in Kansas, due primarily to the distance from $CO_2$ sources. Originally the project proposed to encourage Kansas independents to bring a $CO_2$ pipeline from the Texas Panhandle, however, a closer more efficient source was identified; $CO_2$

output from a 40 million gallon per year ethanol plant. $CO_2$, a fermentation process byproduct of ethanol production, is being utilized for the $CO_2$ miscible flood project in Hall-Gurney field.

The $CO_2$ flood was initiated in December 2003 and showed an initial response in August 2006. The economics are not favorable for the small pilot demonstration, but the project confirms that miscible $CO_2$ flooding is viable for the Lansing-Kansas City formation and that the technology can be applied to other reservoirs in Kansas. The project is ongoing.

## *Thermal Recovery*

**Reactivation of an Idle Lease to Increase Heavy Oil Recovery through Application of Conventional Steam Drive Technology -- Class III**
**Contract**: DE-FC22-95BC14937
**Performer**: University of Utah
**Project Dates**: 6/14/1995 to 3/30/2001
**Miocene Monarch Sandstone –** Midway-Sunset Field, Pru Lease(1,250 ft.), Kern Co., CA, San Joaquin Basin
**Objectives**: The objectives of the project are (1) to return the shut-in portion of the reservoir to commercial production; (2) to accurately describe the reservoir and recovery process; and (3) to convey the details of this activity to the domestic petroleum industry, especially to other producers in California, through an aggressive technology transfer program.
**Results**: The previously idle portion of the Midway-Sunset field, Aera Energy's Pru Fee property, was brought back into commercial production through tight integration of geologic characterization, geostatistical modeling, reservoir simulation, and petroleum engineering. This property, shut-in in 1980 as economically marginal using conventional cyclic steaming methods, had stood idle for over 10 years. The 200-300 foot thick oil column of the Monarch Sand lacked effective steam barriers and had a thick water-saturation zone above the oil-water contact. These factors required an innovative approach to steam flood production design to balance optimal total oil production against economically viable steam-oil ratios and production rates.

Total Pru Fee production following the first steam cycle was 70 BOPD and 300 BWPD in 1996. The average daily production for the 8-acre steam pilot rose to 444 BOPD in March 2000. For the remaining portion of the Pru lease, production rose from 430 BOPD to 760 BOPD. Cumulative incremental production for the 8-acre pilot at the end of the project was 366,000 bbl. Total cumulative incremental production for the 40 acre Pru Fee Lease was over 1.1 million barrels of oil. In addition to the Monarch sand, the study found that the overlying Tulare sand at the Pru Fee lease was productive. A total of 54 wells were drilled in the Pru lease in addition to the nine DOE wells, and daily production rose to over 1,500 bopd in the second half of 2000. AERA transferred the steamflood technology to three adjoining leases. Recoverable reserves were revised to 4.4 million by the end of the project.

As of July 2003 production data from the state of California indicated that production had starting to show a slight natural decline. This is some five years later than the decline curve predicted following inception of the steamflood in 1996, resulting in a much extended reservoir life in the once abandoned lease. Cumulative production passed the 2.52 million barrel mark in March 2004. Monthly production from the 40-acre Pru lease was nearly 30,000 BOPD in 2003-2004.
**Project publication(s)**: Final report BC14937-13 published February 2002.

**Increasing Heavy Oil Reserves in the Wilmington Oil Field through Advanced Reservoir Characterization and Thermal Production Technologies -- Class III**
**Contract**: DE-FC22-95BC14939
**Performer:** City Long Beach, Operator-Tidelands Oil Company
**Project Dates**: 3/30/1995 to 3/31/2007
**Miocene Puente Formation –** Wilmington Field (3,000 ft.), Los Angeles County, CA, Los Angeles Basin
**Objectives**: (1) Develop and apply advanced characterization and production technologies to increase heavy oil reserves and decrease thermal recovery operating costs in slope and basin type reservoirs; (2) apply hotwater alternating steam (WAS) drive, a novel alkaline steam completion technique to control well sanding problems and fluid entry profiles;and (3) implement a pilot horizontal well steamflood project that targets million barrels of oil in the pilot zones.
**Results**: The horizontal well steamflood pilot peaked at 350 BOPD, and stabilized at 300 BOPD. The novel sand completion technique allowed sand free operation using steam consolidation that saved $90K per vertical well and $150K per horizontal well, resulting in 25% reduction of capital costs for drilling wells in unconsolidated sediments. Operating costs were further reduced through application of an innovative new commercial $H_2S$ scrubber technology that can strip out $H_2S$ gases created in the steamflood at a 50% reduction in cost.

During 2002-2003 the project focused on the post steamflood operation in Tar II-A, the Tar V horizontal well steamflood and post steamflood pilots. A new 3-D deterministic reservoir simulation model was developed for the Tar V steamflood pilot in 2004, similar but simpler than the Tar II-A model, to determine the status of reservoir heating from steam injection. At the end of Phase 1 in early 2003 there were 25 active producers and 14 active injectors in Tar II-A, and an horizontal producer in Tar V. The main objectives of Phase 2 were to increase oil production, and improve the water cuts and operating cost structure for the Tar II-A and Tar V projects. The improvements will extend the life of the reservoir and increase oil reserves by an estimated 2-3 million barrels.

Phase 2 work resulted in the redevelopment of the Tar II-A and Tar V post-steamflood projects by drilling a few new wells and converting idle wells to more effectively drain the remaining oil reserves, by improving injection sweep efficiency and reducing water cuts while minimizing further thermal-related formation compaction. Additional testing of cold heavy oil production techniques were conducted due to lack of steam to manimize recovery.
**Project publication(s)**: The final report submitted in August 2007.

## *Chemical Flooding*

**Alkaline-Surfactant-Polymer Flooding and Reservoir Characterization of the Cypress and Bridgeport Reservoirs of the Lawrence Field/Class Revisit**
**Contract**: *DE-FC26-00BC15126*
**Performer**: Plains Illinois
**Project Dates**: 12/7/1999 to 9/12/2005 (ended after Budget Period I, 5/14/03)
**Pennsylvanian and Mississippian Bridgeport and Cypress Formation –** Lawrence Field (3,000 ft.), Lawrence Co., IL, Illinois Basin
**Objectives**: Determine lower cost flood patterns, comparison of EOR techniques, field expansion, and cost efficiencies of flooding multiple reservoirs simultaneously.
**Results**: Sandstones of the Pennsylvanian Bridgeport and Mississippian Cypress formations at Lawrence field, Illinois were producing at less than a 3% oil cut and approaching their economic limit. The 60-acre alkaline-surfactant-polymer ASP project was designed to utilize reservoir

characterization of the fluvial dominated deltaic sandstone reservoirs as a means of reviving production. Lawrence field at 96 years old was reaching a “now or never point” in development with an estimated 40 to 70% of OOIP remaining in place. The ASP flood was designed to target the residual oil and maintain long-term production. The project tested three flood patterns with simultaneous ASP injection in the Bridgeport and Cypress sandstones.
Previous surfactant floods had demonstrated some effectiveness in this field, but had not been cost-effective. The blend of ASP chemicals was expected to increase production in a cost-effective manner, which would benefit other independent producers in the Illinois Basin. The pilot at Lawrence field targeted 42,000 MBO reserves within a 60-acre EOR demonstration. An area of seven sq. miles at Lawrence field was identified as prospective for ASP flooding. Based on the initial response of the ASP pilot the full field project was anticipated to be self-funding after 3 years, which would have extended reservoir life for an additional 14 years. However, the project was terminated at the end of Phase I, due primarily to other commitments of the parent company.
**Project publication(s)**: No final report was submitted, see project Summary Sheet.

## *Microbial EOR*

**Utilization of the Microflora Indigenous to and Present in Oil-Bearing Formations to Selectively Plug the More Porous Zones Thereby Increasing Oil Recovery During Waterflooding -- Class I**
**Contract**: DE-FC22-94BC14962
**Performer:** Hughes Eastern Corporation
**Project Dates**: 1/1/1994 to 6/30/1999
**Mississippian Age Carter Sandstone –** North Blowhorn Creek Field (2,300 ft.), Lamar Co., Alabama, Black Warrior Basin
**Objectives**: Test the ability of indigenous microorganisms to preferentially plug the more porous zones of previously waterswept areas of the Carter sandstone in North Blowhorn Field, Lamar County, Alabama, thereby increasing oil recovery during waterflood.
**Results**: The project differed from other MEOR projects by using inorganic nitrogen and phosphorus fertilizer, and molasses to stimulate the growth of indigenous microorganisms. The nutrients were injected in carefully controlled concentrations and sequences to preclude overgrowth. Live cores from newly drilled wells were employed to validate the nutrient injection scheme and make any necessary adjustments to ensure maximum efficiency. Waterflood fluid diversion in the reservoir through stimulation/growth of *in situ* microoganisms extended the life of the reservoir by 5 years with a total increase of 595,000 bbls of oil above the natural decline. By December 1998 (the end of the project) 69,000 BO had been produced by MEOR. Operators in fields in several other states are considering implementing the microbial technology as the result of presentations on the project. In 2000, the microbial techniques developed in this project were incorporated into the University of Alabama’s Class Revist project at Womack Hill field in Alabama.
**Project publication(s)**: Final report BC14962-24 published November 1999.

## *Simulation*

**Increased Oil Production and Reserves from Improved Completion Techniques in the Bluebell Field -- Class I**
**Contract**: DE-FC22-93BC14953
**Performer**: Utah Geological Survey

**Project Dates**: 9/30/1993 to 9/29/1999
**Eocene Green River & Wasatch Fm. –** Bluebell Field (10,000 to 14,000 ft.), Duchesne Co., Utah, Uinta Basin
**Objectives**: (1) Develop a multidisciplinary reservoir characterization approach to overcoming low petroleum recovery caused by poor completion practices in fractured, clayey reservoirs in the Bluebell field, Uinta Basin, northeast Utah; (2) demonstrate the application of multidisciplinary geological and engineering techniques, such as facies analysis and fracture trend analysis to improve production and increase reserves; and (3) conduct a technology transfer plan that includes workshops and database distribution.
**Results**: The primary problem with completing wells in the Bluebell field was adequately identifying pay zones in the thick, heterogeneous sequence. The project was primarily a drilling and recompletion program, but analysis carried out by a subcontract at the University of Utah employed numerical simulation to estalish the optimum zones to perforate. Pre-completion logging analysis using simulation runs were instrumental in reducing the number of zones selected for completion in the 3rd well well drilled. Typically 40 to 60 beds are selected for completion based mainly on drilling shows. In the new well, 19 zones were pereforated. The benefits included lower completion costs, increased productivity of treated zones, and a reduction in produced water.
**Project publication(s)**: Final report published January 2000, two topical reports (one on simulation) were published in July 2000.

## *Waterflooding*

Secondary Oil Recovery From Selected Carter Sandstone Oil Fields -- Class I
**Contract**: DE-FC22-93BC14952
**Performer**: Anderman/Smith Operating
**Project Dates**: 10/21/1992 to 11/30/1994
**Mississippian Carter Sandstone –** Bluff and North Fairview fields (2,500 ft.), Lamar Co., Alabama, Black Warrior Basin
**Objectives**: (1) Initiate waterflooding of Carter sandstones at three sites in the Bluff and North Fairview fields where the major production constraints are low bottomhole pressures and reservoir heterogeneity; (2) quantify heterogeneities using standard geological and production/reservoir studies and reservoir computer simulation; (3) develop a methodology for optimum application of geologic and engineering reservoir characterization technologies; and (4) transfer project results to industry.
**Results**: The project developed a methodology for optimum application of geologic and engineering reservoir characterization technologies and initiated a waterflood. Water injection began at the North Fairview Unit in June 1993 and oil production increased only 45 bopd after initiation. The project terminated prior to the end of Phase I.
**Project publication (s):** No final report submitted.

**Improved Secondary Recovery Demonstration for the Sooner Unit -- Class I**
**Contract**: DE-FC22-93BC14954
**Performer**: Diversified Operating
**Project Dates**: 10/21/1992 to 11/30/1995
**Cretaceous Muddy (D) Formation –** Sooner Unit (6, 300 ft.), Weld Co., CO, Denver-Julesburg Basin
**Objectives**: Demonstrate the cost-effectiveness of geologically targeted infill drilling and improved reservoir management to increase waterflood recovery of the Cretaceous Muddy "D" formation in the Denver-Julesburg Basin, northeast Colorado.

**Results**: The “D” Sand had good primary recovery but disappointing waterflood performance. The majority of waterflood projects produced only about 20% of the OOIP. Poor waterflood recovery was attributed to reservoir heterogeneity and poor reservoir management practices. Three-dimensional seismic had not been used in the D-J Basin for exploration or development of “D” Sand reservoirs prior to this project.
An effective tool for targeting infill and edge locations was developed using attribute correlation of 3-D seismic with petrophysical data. The 3-D survey at the Sooner Unit precipitated an additional 13 3-D surveys in the D-J Basin for the purpose of “D” Sand development and exploration by the end of the project in 1996. As of February, 1996 daily production from the Sooner Unit had increased more than 100% above the trend established before the project was initiated. Incremental proved-producing reserves attributed to the project was 305,000 bbl. Recovery had been boosted from 15% OOIP to 20% by mid 1996.
**Project publication(s)**: Final report BC14954-14 published November 1996.

**Green River Formation Water Flood Demonstration Project -- Class I**
**Contract**: DE-FC22-93BC14958
**Performer**: Inland Resources (formerly Lomax Exploration)
**Project Dates**: 10/21/1992 to 3/31/1996
**Eocene Green River Formation –** Monument Butte Unit (5,600 ft.), Duchesne Co., UT, Uinta Basin
**Objectives**: (1) evaluate the success of the Monument Butte Unit waterflood and determine the recovery mechanisms, (2) extend the waterflooding technology to the nearby Travis and Boundary Unit project areas, (3) develop new techniques to characterize reservoir heterogeneity and evaluate the response of the reservoir to the waterflood, and (4) transfer the technology to operators, regulators, and other government agencies.
**Results**: Waterflooding technology was not commonly used in the Uinta Basin due to the low permeability, heterogeneity and paraffinic oil of the reservoirs. Primary methods produced about 5% of the original oil in place (OOIP). Production from waterflooding was estimated to increase recovery to 20% of OOIP. This project was initiated by Lomax Exploration, which was sold to Inlands Resources during the course of the project.

At the end of the project, December 1994, a total of 241,768 bbl of incremental oil was produced from the Monument Butte and Travis Units. Both the waterflooding process demonstrated and the techniques used were applied to other fields in the area, as well as to other high-paraffin, heterogeneous reservoirs. Thirteen waterflood projects were initiated by other companies in the area. The widespread application of the waterflooding technology to other high-paraffin oil reservoirs has added reserves estimated to be in the tens of millions of barrels of oil.

In 2003 NETL reviewed the project as part of an analysis of the long term benefits of DOE R&D. Inland Resources credited the expansion of the pilot from a 2 section Monument Butte Unit to the entire 125,000 acre field entirely to the technology developed under DOE’s funding. The return on the R&D investment averaged an annual rate of 33% from 1992 to 2003. The life of the Monument Butte reservoir was extended by up to 20 years. Three large independent operators, Petrocliffe, Questar and Berry Petroleum acquired leases in the area to expand the waterflood technologies developed by Lomax/Inlands across the Uinta Basin.
**Project publication (s)**: Final report BC14958-15 published November 1996.

**An Integrated Study of the Grayburg/San Andres Reservoir, Foster and South Cowden Fields, Ector County, Texas -- Class II**
**Contract**: DE-FC22-93BC14982
**Performer**: Laguna Petroleum Company

**Project Dates**: 8/2/1994 to 8/2/2000
**Early Permian Grayburg/San Andres Fm. –** Foster & South Cowden fields (4,200 ft.), Ector Co., TX, Permian Basin.
**Objectives**: Demonstrate that 3-D seismic data can be used to aid in identifying porosity zones, permeability barriers, and thief zones and thereby improve waterflood design.
**Results**: In 1994, Foster and South Cowden fields were reaching their economic limit and the 68-year old lease was expected to be abandoned within 10 years. A multi-disciplinary approach to waterflood design and implementation along with selective infill drilling and deepening was designed to increase reserves, extend reservoir life, and improve production. Reservoir characterization was improved by the integration of seismic derived reservoir properties, geological characterization techniques, and 3-D reservoir simulation.

Added reserves from the project were approximately 2.5 million bbl. Potential additional incremental reserves, assuming the technology were to be applied to other shallow shelf carbonate reservoirs in the Permian Basin, were estimated to be greater than 1.5 billion bbl. From June 1996 to September 1998, field production increased from 9,700 BOPM to 14,000 BOPM. Incremental production as of September 2000 was 190,000 barrels of oil. Four wells in Foster/S. Cowden fields demonstrated a 7-fold production increase. Estimates of reserves arrived at in 1996 were 403,000 bbl with nine years of reservoir life remaining. In September 1999, the new estimate of reserves based on decline curves was 973,000 bbl with 16 years of reservoir life remaining.
**Project publication(s)**: Final report BC14982-20 published April 2001.

**Application of Integrated Reservoir Management and Reservoir Characterization to Optimize Infill Drilling -- Class II**
**Contract**: DE-FC22-93BC14989
**Performer**: Fina, USA
**Project Dates**: 6/13/1994 to 6/12/1999
**Permian Clearfork Formation –** North Robertson Field (6,500 ft.), Gaines Co., TX, Permian Basin
**Objectives**: Demonstrate the application of advanced secondary recovery technologies to remedy producibility problems in shallow-shelf carbonate reservoirs in the Permian Basin.
**Results**: Typical Clearfork reservoirs have recovered only 15% to 22% of the oil they originally contained, and use of targeted infill drilling in combination with waterflooding could recover as much as 2.5 billion barrels of additional oil from these reservoirs alone. At North Robertson, cross-borehole tomography, geostatistical modeling, and rigorous decline type curve analysis, were used to quantify reservoir quality and the degree of interwell communication. These results were used to develop a 3-D simulation model for prediction of infill locations. Unit production averaged approximately 2700 BOPD at the end of the project with the contribution from 14 waterflooded producing wells averaging 400 BOPD. This was a 26% increase in production for the Unit, resulting in an overall increase of field production of 18% since beginning the field demonstration.
**Project publication(s)**: Final report DE-FC22-93BC14989-23 published March 2000.

**Advanced Reservoir Characterization and Development Through High Resolution 3C3D Seismic and Horizontal Drilling: Eva South Morrow Sand Unit, Texas County, OK/Class Revisit**
**Contract**: DE-FC26-00BC15120
**Performer**: Ensign Operating Company
**Project Dates**: 2/29/2000 to 7/31/2001

**Pennsylvanian Morrow Formation –** Eva South Field (5,600 ft.), Texas Co., OK, Anadarko Basin (Hugoton Embayment)
**Objectives**: Improve waterflood sweep efficiency at the Eva South Unit, Oklahoma using high resolution 3C3D (three component 3D) seismic and horizontal drilling.
**Results**: Ensign Operating Company acquired the field in 1993 and initiated a waterflood project. The field responded in nine months. Due primarily to compartmentalization, it was determined that an additional 450,000 barrels of oil could be recovered if sweep efficiency could be improved. Four reservoir compartments formed by abandoned channel-fill deposits and faulting defined the Eva South Unit. Synthetic seismic models were constructed that indicated the compartmentalization could be resolved through high-resolution 3D seismic.

In additional to the standard compressional (P-wave) component, two mode-converted shear-wave (S-wave) components were recorded (3C3D). The 3C3D seismic was used to identify the location of a horizontal well which was successful in adding 122,000 barrels of incremental reserves, representing 1.7% of the original oil in place in the field.

The project produced two recommendations for drilling horizontal wells in the Morrow formation: (1) operators should review the drilling records of all wells in the area for indications of lost circulation prior to directional drilling and plan corrective action as part of the drilling program; and (2) horizontal wells in the Morrow should be drilled until a few feet of the reservoir has been encountered, then casing should be set immediately to minimize the potental for sloughing or caving of the shale intervals. The project ended in March 2002, and in a July 2003 update Ensign indicated that they plan future horizontal wells and 3C3D seismic.
**Project publication(s)**: Final report published March 2002.

# Appendix B. Summaries of Selected EOR Projects

Appendix B provides summary details on another 56 individual projects selected from the total of 322 as particularly significant in terms of their contribution to the progress of EOR nationwide. The projects summarized below were conducted from 2001 to 2007.

## *Gas Injection*

**Improvement of Sweep Efficiency in Gas Flooding**
**Contract**: DE-FC26-04NT15535
**Performer**: University of Houston
**Project Dates**: October 1, 2004 - September 30, 2007
**Objectives**: (1) Evaluate sweep efficiency of various miscible flooding processes in a laboratory model; (2) develop numerical tools to estimate sweep efficiency at the field scale; and (3) identify solvent composition, mobility control method, and well architecture that improve sweep efficiency.
**Results**: A high-pressure quarter 5-spot cell was constructed to conduct multicontact miscible WAG displacements at reservoir conditions. Multicontact miscible solvents were identified by conducting slimtube experiments for a medium viscosity oil (78 cp). Coreflood experiments were conducted to determine microscopic displacement efficiency as a function of WAG ratio. Quarter 5-spot experiments were conducted to infer sweep efficiency in a 3-D geometry at the laboratory scale. A compositional model has been developed to simulate such displacements in the laboratory and in the field.

As of January 2006, researchers had completed four subtasks: slimtube tests, high-pressure model construction, corefloods, and 1-D compositional modeling. Three-dimensional modeling of the sweep efficiency of gas/WAG floods were conducted. Tests of other oil/solvent systems and foams and field-scale modeling were conducted in 2007. The following observations have been made from the work performed:

- Ethane is a multi-contact miscible solvent for one of the oils tested at pressures higher than 1,340 psi. WAG improves the microscopic displacement efficiency (~100%) over continuous gas injection followed by waterflood (~67%) in corefloods.
- WAG improves oil recovery (~75%) in the quarter 5-spot over continuous gas injection followed by waterflood (~64%). WAG injection slows down gas breakthrough. A decrease in the slug size improves the oil recovery in WAG floods. Use of a horizontal production well lowers oil recovery vs. a vertical production well during continuous gas injection.
- The sweep efficiency was not measured directly in the quarter 5-spot cell, but it is expected that as the recovery increases so does the sweep efficiency. These experiments will be matched by compositional simulations to infer the sweep efficiency of these processes.

**High Resolution Production of Gas Injection Process Performance for Heterogeneous Reservoirs**
**Contract**: DE-FC22-00BC15319
**Performer:** Stanford University
**Project Dates**: 9/01/ 2000 – 2/ 29/2004
**Objectives**: Develop a new set of ultra-fast reservoir simulation tools for the prediction of interactions of phase behavior of complex oil/gas mixtures with flow in heterogeneous reservoirs.
**Results**: A three-dimensional (3-D), streamline-based compositional simulator was developed. It allows assessment of the performance of gas displacement processes using numerical or

analytical solutions for multi-component displacement along a streamline in combination with high-resolution representation of heterogeneities in the calculation of streamline locations. The resulting predictions of process performance were found to be more accurate than conventional finite-difference compositional simulations and could be obtained in a fraction of the computation time. The computational technique developed allows accurate analysis of gas injection processes at field scale. Conventional compositional simulation was too slow to allow such analysis at field scale; hence the results of this project make possible detailed process performance predictions that could not be done before.

**Industrial Compositional Streamline Simulation for Efficient and Accurate Prediction of Gas Injection and WAG Processes**
**Contract**: DE-FC26-04NT15530
**Performer**: Stanford University
**Project Dates**: 10/1/2004 – 9/30/2007
**Objectives**: (1) extend and improve a novel and fully adaptive compositional streamline simulator CSLS to three-phase flow; (2) increase its computational efficiency, so that it will be suitable for use in industry and laboratories for the study of realistic reservoir and production scenarios for a wide variety of gas injection and CO2 sequestration projects.
**Results**: On this project, work has shown that compositional streamline simulation (CSLS) has very high potential for the simulation of (near) miscible gas injection processes. Researchers extended and improved a novel and fully adaptive compositional streamline simulator CSLS to three-phase flows. The goal is to increase its computational efficiency, so that it will be suitable for use in industry and laboratories for the study of realistic reservoir and production scenarios for a wide variety of gas injection and $CO_2$ sequestration projects. The simulator development is supported by an experimental program designed to improve understanding of three-phase flows, which could lead to improved mathematical models for three-phase relative permeability functions. Researchers developed:

- A novel and accurate pressure solver on Cartesian Cell-based Anisotropically Refined (CCAR) grids. The adaptivity allows refinement in important flow zones, which greatly improves the flow accuracy.
- A novel multi-level permeability and transmissibility upscaling strategy for CCAR grids that significantly reduces the process dependency of the flow solver. This strategy is applicable to other grid refinement strategies.
- A relaxation method for the accurate solution of multi-phase, multi-component flows. Preliminary results showed this new method may resolve numerical difficulties associated with the strong nonlinearities inherent in these problems.

The CSLS has a high potential for use in quick and reliable assessments of performance and development of management strategies for a wide range of reservoirs involving multi-phase flows. The high-resolution capabilities of CSLS will contribute to a better understanding of the physical processes of multi-phase, multi-component flows in porous media. CSLS will provide fast and accurate performance predictions of oil and gas reservoirs. It is suited for coupling to optimization algorithms for well placement, surface facilities locations, or reservoir management strategies and will enable optimization studies to be performed in realistic timeframes by industry. This is especially important in remote and/or hostile areas where infill drilling may not be an option and production costs are high.

**Advanced Technology for Predicting the Fluid Flow Attributes of Naturally Fractured Reservoirs from Quantitative Data and Modeling**
**Contract**: DE-FC22-01BC15318
**Performer**: University of Texas at Austin

**Project Dates**: 9/28/2000 – 1/15/2004
**Objectives**: Provide the scientific and engineering basis for improved design of foam processes for enhanced oil recovery, by studying polymer-enhanced foam, gas trapping in the presence of foam, and mechanisms of foam generation.
**Results**: Numerical models and simulation studies of foam mechanism were developed to improve prediction of foam movement through the reservoir. An area of unstable foam generation was identified that provided important information for foam design in field applications. This research provided the foundation for more-accurate predictive modeling of foam processes to improve oil recovery, improve process design, enable wider application of foams and gas injection, and increase domestic oil production.

**Reviving Abandoned Reservoirs with High-Pressure Air Injection: Application in a Fractured and Karsted Dolomite Reservoir**
**Contract**: DE-FC26-02NT15442
**Performer**: University of Texas
**Project Dates**: 10/1/2002 – 9/30/2006
**Objectives**: Evaluate the applicability of high-pressure air injection (HPAI) in revitalizing a nearly abandoned carbonate oil reservoir in the Permian Basin of West Texas.
**Results**: The Lower Ellenburger carbonate reservoir studies indicated a complex fractured reservoir where the fractures were produced by karst (collapsed paleocave) processes. A simulation model was developed based on available laboratory and field data. The model was utilized to perform waterflood and air injection simulation runs in stratified and fractured reservoir environments. The results obtained after an extensive history-matching exercise using combustion tube data indicate that the reservoir under study is a very good candidate for HPAI. Initial field results indicated that HPAI does work in the field. Early results from the pilot demonstrated that the technology is a success in the reservoir. High-pressure air was injected in a test well, and results indicated that combustion took place and a response was recorded in the producing well. This program is designed to help oil and gas operators effectively apply an exciting new technology that has a huge potential for dramatically increasing the recovery of oil from underexploited, mature carbonate reservoirs. HPAI previously has been applied in heavy oil reservoirs but only rarely attempted in light oil reservoirs, where a much greater remaining oil resource lies. Researchers tested this technology in a carbonate reservoir that, because of pressure depletion, had been nearly abandoned. Success from this study will stimulate application throughout the Permian Basin.

**Improved Gas Flooding Efficiency**
**Contract**: DE-FC26-04NT15532
**Performer**: New Mexico Technological Institute
**Project Dates**: 4/1/2005 – 9/30/2007
**Objectives**: (1) Acquire the information to develop adsorption/desorption models for reservoir rock at reservoir conditions; (2) determine economic sweep efficiency and injectivity criteria for reservoir scale systems; (3) expand foam gas flooding to shallow reservoirs; and (4) develop models and modules for simulating carbon dioxide flooding mechanisms.
**Results**: This work was based on laboratory tests, supplemented with modeling to determine practical information for designing gas foam systems for a wide range of reservoir types. Major accomplishments include the following:

- Designing, setting up, and testing a large, high-pressure, high-temperature coreflood apparatus for testing foam adsorption, desorption, and mobility changes due to foam, and consequent oil recovery.
- Performing adsorption, desorption, and mobility tests at reservoir conditions and at various surfactant concentrations and foam quality at reservoir pressure.

- Determining rate of adsorption versus available system surfactant for powdered, pure core material; several rock core samples; and surfactant types.
- Ascertaining the rate of gas saturation reduction versus saturation of flowing brine.

Project results are expected to benefit the future of gas injection IOR by; reducing surfactant cost, expanding $CO_2$ flooding to low-pressure reservoirs, delaying production of $CO_2$ and/or increasing retention of $CO_2$ in geologic formations, and improving injectivity of $CO_2$ and water, enhancing $CO_2$ flooding predictions, and decreasing $CO_2$ mobility.

## *$CO_2$ Injection*

**Origin of Scale-Dependent Dispersivity and Its Implications for Miscible Gas Flooding**
**Contract**: DE-FC26-04NT15534
**Performer**: University of Texas at Austin
**Project Dates**: 10/1/2004 – 9/30/2007
**Objectives**: (1) perform a novel fundamental study of the mechanism of dispersion; (2) develop an improved multiscale statistical model of dispersion: (3) use this advance in understanding to optimize field-scale gas injection.
**Results**: Conducting organic polymer-based nitrate ion selective electrodes (ISEs) were fabricated at sizes ranging from 7 to 100 microns in diameter. These prototypes were successfully tested in batch systems with small reference electrode (2 mm diameter). The reference electrode was miniaturized to make it optimal for use with micron-scale ISEs in porous media tests. Column tests with the new sensors were successfully completed. High-resolution simulations of fluid flow in two-dimensional models of heterogeneous porous media established a pore-scale basis for non-locality of dispersivity. Re-analysis of dispersivity vs. length data summarized in the literature show that lithology accounts for much of the scatter, and that dispersivity values level off at greater lengths.

The ultimate oil recovery efficiency from $CO_2$ injection is low. The $CO_2$ utilization rate—the amount of $CO_2$ injected to recover a barrel of oil—is high. The performance of a $CO_2$ process is strongly influenced by hydrodynamic dispersion, but the basis for dispersion and rigorous methods for modeling it remain poorly understood.

**Time-Lapse Seismic Modeling and Inversion of $CO_2$ Saturation for Sequestration and Enhanced Oil Recovery**
**Contract**: DE-FC26-03NT15417
**Performer**: 4th Wave Imaging Corp.
**Project Dates**: 9/30/2003 – 12/31/2005
**Objectives**: (1) improve current methods of rock physics and time-lapse seismic reflection modeling for $CO_2$ sequestration and miscible $CO_2$ floods in oil and gas reservoirs; and (2) develop new strategies to invert such data to estimate changes in pressure, oil saturation, water saturation, and $CO_2$ saturation over time.
**Results**: This project has resulted in new algorithms to accurately model time-lapse seismic changes during $CO_2$ injection and to invert these data to estimate changes in reservoir properties, such as pressure and $CO_2$ saturation that cause the seismic anomalies. Both modeling and inversion algorithms rely on rock physics relations to estimate seismic parameters, such as velocities and densities, as a function of $CO_2$ saturation and pressure. Among the major achievements of this project, researchers have:

- Investigated new ways to compute fluid properties of oil-water-$CO_2$ mixtures using both EOS methods and molecular dynamics modeling.
- Wrote a 1-D seismic modeling program that uses time-lapse changes in well-log velocities and densities to predict changes in seismic data during $CO_2$ injection.
- Wrote an algorithm to accomplish the first step of the inversion procedure, namely, the generation of time-lapse seismic attribute changes as a function of changes in $CO_2$ saturation and pressure.
- Completed a preliminary evaluation of time-lapse seismic anomalies in different vintages of the Sleipner North Sea 3-D data set.

$CO_2$ is widely viewed as an important agent in global warming. In addition, miscible $CO_2$ flooding has become an increasingly important enhanced oil recovery (EOR) method for recovering residual or bypassed oil. For example, roughly half the $CO_2$ floods in the world are located in the Permian Basin, accounting for more than 20% of the area's total oil production. By developing an accurate approach for tracking $CO_2$ fronts during EOR operations, this project is expected to help improve recovery rates, optimize well patterns, locate bypassed oil, and minimize the cost of injected $CO_2$. Project results will also benefit the public by improving current methods for monitoring reservoir leaks and verifying the location and quantity of sequestered $CO_2$ in order to minimize its emission.

**Demonstration of a Novel, Integrated, Multi-Scale Procedure for High-Resolution 3D Reservoir Characterization and Improved $CO_2$-EOR Sequestration Management, SACROC Unit, TX**
**Contract**: DE-FC26-04NT15514
**Performer**: Advanced Resources International
**Project Dates**: 9/20/2004 – 3/31/2007
**Objectives**: (1) Demonstrate the application and benefits of data-driven modeling for multi-scale data integration for high-resolution 3-D reservoir characterization to better address management of $CO_2$ EOR floods and carbon sequestration projects; and (2) use advanced pattern-recognition technologies (self-organizing maps, artificial neural networks, and fuzzy logic) to establish relationships between data at different scales, and by doing so, create a "transform" to derive core-scale reservoir properties from 3-D surface seismic data.
**Results**: Preliminary research was done to compare advantages and drawbacks of various data-driven modeling techniques currently utilized in reservoir characterization tasks. A model-based neural system was adopted. The mathematical framework of this system is called Maximum Likelihood Adaptive Neural System; it is a neural system that combines *a priori* knowledge, adaptability, and fuzzy logic. Statistical analysis of geophysical well logs was done to provide summary descriptions, cross-information, and detection of trends, correlations, and possible anomalies. Pattern recognition procedures were applied in a cored well to produce preliminary rock-type classifications and to test the influence capacity of different types of geophysical well logs.

Oil reserves in the Permian Basin are estimated at 4.2 billion barrels. If the proposed technology can be applied to only 5% of the reservoirs that correspond to this reserve estimate and can improve recovery on average by 25% (i.e., improving recovery from 40% to 50% of OOIP), the technology developed in this project would facilitate the recovery of 53 million barrels of additional oil. At a market price of $50/bbl (2006), an increase in economic activity of $2.65 billion would result. If the local, state, and federal government share of that economic activity were 20% (i.e., production taxes, employment taxes, income taxes, etc.), the government share would be $530 million. Even if substantially reduced by the application of risk factors, the potential payoff for the project, for industry and government alike, is highly attractive.

**Oil Reservoir Characterization and $CO_2$ Injection Monitoring in the Permian Basin with Cross-Well Electromagnetic Imaging**
**Contract**: DE-FC26-00BC15307
**Performer**: ElectroMagnetic Instruments
**Project Dates**: 9/11/2000 – 8/2/2004
**Objectives**: (1) Build on the previous development of resistivity logging tools to develop cross-well imaging hardware and software; (2) calibrate and field-test the transmitter and receiver systems; (3) use the cross-well imaging tool for monitoring carbon dioxide injection; and (4) develop a cross-well electromagnetic system (EM) to provide a formation resistivity distribution between steel-cased wells and apply it in the Permian Basin.
**Results**: The Crosswell Electromagnetic Imaging Tool was developed at Lawrence Livermore National Laboratory (LLNL) from 1991 to 2000. ElectroMagnetic Instruments, Inc. (EMI) was created by former LLNL scientists to further the research and commercialization of the Crosswell Electromagnetic Imaging downhole logging tool. EMI developed a five-well pattern test site in Richmond, CA, to continue testing and construction of the tool prior to commercial field tests.

Crosswell electromagnetic logging involves the use of a string of receivers in one well and a transmitter lowered into a neighboring wellbore. The development of sensitive receivers, advanced transmitters, and fiber optics was an essential part of the implementation of crosswell logging, and these advances have been incorporated into the development of the EM extended-logging tool. The project has refined transmitter and geophone receiver design and deployed the EM tool in uncased, fiberglass-cased, and steel-cased wellbores.

The Geo-BILT tool, a modified prototype EM imaging tool designed and tested by EMI, successfully demonstrated that multicomponent logging was applicable in several different geological environments. Geo-BILT has the advantage that it is capable of single-well extended logging. The tool uses a transmitter situated 3 meters above the receivers on a line and provides a 3-D image of the wellbore area up to a radius of 50 to 250 meters. Single-well logging will significantly reduce logging cost while providing critical reservoir data.

Crosswell electromagnetic imaging was used to monitor $CO_2$ injection performance in New Mexico’s Vacuum field, operated by ChevronTexaco. This project involved development of crosswell EM dual-steel casing logging tools, software development, data processing, and imaging of low-induction frequencies. The results were used to develop resistivity models showing the distribution, size, and depth of the low-resistivity zones, which could be correlated to interwell $CO_2$ migration.

**Technology Development and Demonstration of Microhole Oil Production at the Rocky Mountain Oilfield Test Center**
**Contract**: FEW03FE06-04
**Performer**: Los Alamos National Laboratory
**Project Dates**: May 2004 – May 2006
**Objectives**: (1) Demonstrate that microholes provide downhole access at significantly lower cost than conventional-sized wells, and provide superior acoustic performance when compared to the use of temporarily converted production or injection wells; and (2) evaluate new prototypes of commercial drilling equipment.
**Results**: The use of production and injection wells for seismic data acquisition has a number of disadvantages. Deploying seismic sensors and other logging type tools interrupts field operations

resulting in loss of money through temporarily stopping production and idle time for expensive machinery and equipment.

Production and injection wells are often not positioned in the most advantageous locations for obtaining reservoir data. Conventional wells dedicated to seismic monitoring are expensive to drill. Microholes (wellbores less than 3 ½ inch diameter) have the advantage of being relatively inexpensive to drill and locations and completion designs can be selected for optimal acquisition of seismic data. In previous DOE-funded projects, Los Alamos National Laboratory has demonstrated that coiled-tubing microdrilling of wells as small as 1¾ -inch in diameter and as deep as 800 ft can be achieved. The Los Alamos team also successfully field-tested geophysical micro-instrumentation in microholes cased with 1 ¼ inch tubing.

Project researchers demonstrated the technical and economic feasibility of developing a highly mobile, self-contained, microhole drilling system for seismic data acquisition and other applications. Using prototype systems to simulate the concept microhole drilling system, LANL drilled and completed six microwells at the RMOTC Teapot Dome field. Researchers demonstrated the technical feasibility of microdrilling 1 ½ - 2 ½ inch holes to depths of as much as 1,310 feet using coiled tubing-deployed drilling assemblies consisting of PDC (polycrystalline diamond compact) bits and PDMs (positive displacement motors).

**Technology Development and Demonstration/Microholes for Designer Seismic in Support of $CO_2$ EOR**
**Contract**: FEW03FE06-06
**Performer**: Los Alamos National Laboratory
**Project Dates**: 2/15/2006 – 2/14/2007
**Objectives**: Demonstrate that a Coiled Tubing Microhole Drilling Rig can be used to drill shallow (800 feet) instrumentation wells for the installation of the Microhole Vertical Seismic Profile Array in order to monitor the movement of injected Carbon Dioxide into an oil reservoir for the purposes of EOR and $CO_2$ Sequestration.
**Results**:  Field demonstrations were conducted at RMOTC's Teapot Dome oilfield at the Naval Petroleum Reserve No. 3 in Central Wyoming using a prototype coiled tubing unit, an off-the-shelf drilling-mud cleaning unit, and a surplus shallow-well cementing unit to simulate a highly mobile, self-contained, microhole drilling system. These supported microdrilling operations and optimize drilling performance using off-the-shelf components that in many cases were not designed for—nor well suited for—openhole drilling service.

**Implementing a Novel Cyclic $CO_2$ Flood in Paleozoic Reefs**
**Contract**: DE-FC26-02NT15441
**Performer**: Michigan Technological University
**Project Dates**: 1/2/2003 – 12/31/2005
**Objectives**: (1) demonstrate that significant quantities of bypassed hydrocarbons can be recovered from pinnacle reefs with a novel $CO_2$ cycling technology; (2) conduct a field demonstration, identifying abandoned or shut-in reefs that are suitable candidates for similar recovery efforts; and (3) communicate the project results and data to small, independent producers via an aggressive technology transfer program.
**Results**:  Two $CO_2$ projects in the Michigan pinnacle reefs had reported incremental production of 160,000 and 430,000 barrels. Those volumes represent 14% and 33%, respectively, of the primary recovery produced in just 5 years. One of the projects, at Dover field in Otsego County, is close this project's demonstration well. Data released to the State of Michigan indicated that the $CO_2$ flood restored the production to nearly initial conditions. However, the details of the

operations were not been made public, and this has been a serious impediment to widespread adoption of the technology.

Pinnacle reefs have a high vertical relief and are nearly hermetically sealed. $CO_2$ was injected into the top of the reef, and the hydrocarbons were collected from a horizontal drain well drilled at the base of the reef. The $CO_2$ was obtained from nearby natural gas wells producing from the Antrim Formation, where the gas was compressed and dehydrated, then piped a short distance (1 mile) to the demonstration well. There it was injected to bring the reef back to nearly virgin pressure, and the remobilized hydrocarbons migrated to the bottom of the reservoir as the gas cap expanded.

Nearby well logs that penetrate the reef were analyzed using a new approach that has been developed at Michigan Technological University. This approach has been termed Log Curve Amplitude Slicing (LCAS) and uses suites of well logs to map the horizon of interest at 1-foot intervals, essentially utilizing the full information content of the log. The technique is similar to mapping formation tops from log picks or drillers' reports, except that the attribute is mapped at much more closely spaced intervals (e.g., 1 foot).

A production response of more than 80 barrels of oil per day resulted from the initial stage of repressurization of a depleted Niagaran pinnacle reef using Antrim waste $CO_2$. Detailed reservoir modeling of Niagaran reefs using the technique of well log tomography is producing a new reservoir characterization tool that can be used for the visualization of permeability and porosity distribution in oil and gas reservoirs.

**Improved $CO_2$ Efficiency for Recovering Oil in Heterogeneous Reservoirs**
**Contract**: DE-FC26-02BC15364
**Performer**: New Mexico Petroleum Recovery Research Center (PRRC)
**Project Dates**: 9/28/2001 – 9/27/2005
**Objectives**: Increase effectiveness and viability of $CO_2$ mobility control by using foaming systems to minimize injectivity losses and to model these mechanisms.
**Results**: Despite favorable characteristics of $CO_2$ for enhanced oil recovery, $CO_2$ floods frequently experience poor sweep efficiency caused by gas fingering and gravity override exacerbated by reservoir heterogeneity. Also, low productivity results from lower-than-expected injectivity. Poor sweep efficiency results from a high mobility ratio caused by the low viscosity of high-density $CO_2$ compared with that of water or oil. The effectiveness of water injection alternating with gas (WAG), a common process used for mobility control during $CO_2$ floods, is reduced by gravity segregation between water and $CO_2$ and amplified by permeability differences. Foaming agents have been introduced in the aqueous phase to control mobility. However, costs incurred by the loss of expensive chemicals to adsorption on reservoir rock often exclude this potentially beneficial option for many well operators.

Systems were developed with low concentrations of good foaming agents that will reduce cost. These systems are derived using a sacrificial agent or a co-surfactant that shows synergistic improvements when mixed with the good foaming agents. Project researchers have achieved the following milestones/insights:

- WAG coreflood experiments conducted on limestone and dolomite core plugs confirmed that carbonate mineral dissolution and deposition can occur over relatively short time periods (hours to days) and in close proximity to each other.
- Two series of core experiments, with nitrogen ($N_2$) and with $CO_2$ injected through core samples, indicate that although the Forchheimer equation is useful in describing high-velocity flow in porous media, in many cases it is not sufficient.

- Results of high-pressure/high-temperature/high-velocity gas flooding experiments on five different rock samples (sandstones and carbonates) under reservoir conditions reconfirm—and extend to new conditions—that permeability increases, while the non-Darcy flow coefficient decreases with increasing effective stresses; both are independent of shear stresses.
- The results of a series of tests on $CO_2$ foams identified reductions in chemical costs derived from the synergistic effects of co-surfactant systems using a good foaming agent and a less-expensive but poor foaming agent. The required good foaming agent was reduced by at least 75%. Additionally, the deleterious effect on injectivity was reduced by as much as 50% using the co-surfactant system, compared with a previously used surfactant system.
- The order (highest to lowest) of calcium lignosulfonate (CLS) adsorption onto five powdered pure minerals common to oil reservoirs is montmorillonite > kaolinite > dolomite > calcite > silica. In each case, adsorption is complete within 1 hour. Core samples of sandstone, limestone, and dolomite took an order of magnitude longer to equilibrate. This difference appears to be related to the pore structure.

**Investigation of Efficiency Improvement during $CO_2$ Injection in Hydraulically and Naturally Fractured Reservoirs**
**Contract**: DE-FC26-01BC15361
**Performer**: Texas Engineering Experimental Station, Texas A&M University
**Project Dates**: 9/28/2001 – 9/27/2005
**Objectives**: Perform unique laboratory experiments with artificial fractured cores (AFCs) and X-ray computer tomography (CT) to examine the physical mechanisms of bypassing in hydraulically and naturally fractured reservoirs that eventually result in less efficient $CO_2$ flooding in heterogeneous or fracture-dominated reservoirs.
**Results**: The fundamental mechanisms of $CO_2$ movement through fracture systems are virtually unexplored. The goal of the proposed work was to advance the understanding of this dynamic process and determine the implications on the ultimate performance of bypassing reserves during $CO_2$ injection.

This project used an X-ray CT scanner to image saturation profiles of flow patterns for direct measurement of bypassing mechanisms and to measure bypassed oil to optimize $CO_2$ flooding efficiency. With this equipment, researchers have established the relationship between fracture aperture distribution and overburden pressures. They found that $CO_2$ gravity drainage still plays an important role in oil recovery, even in a short-matrix block. $CO_2$ sweep efficiency was improved significantly by controlling the $CO_2$ mobility in the fracture with viscosified water and placing a cross-linked gel in the fracture. Project highlights include the following:

- New laboratory experiments have been developed to 1) demonstrate the effect of different overburden pressures and injection rates on fracture aperture and matrix and fracture productivities, and 2) mitigate bypassing mechanisms that will result in less bypassing and more-efficient $CO_2$ flooding in fracture-dominated reservoirs.
- Tests that varied $CO_2$ injection rates and WAG (water-alternating-gas) injection ratios were conducted at the laboratory scale. Fluid flow experiments where a gel polymer was placed in the fracture system were also performed.
- The laboratory techniques have been used to reduce $CO_2$ bypassing and optimize $CO_2$ flood design in the Wasson Field of west Texas.
- Analytical and numerical modeling has been performed to 1) investigate the effect of fracture aperture at variable overburden pressure, 2) study the effect of different rock heterogeneity on flow path contributors, 3) validate the use of cubic law equation, 4) examine the transfer

mechanism during core flooding in fractured cores, and 5) assess the effect of grid orientation in different mobility ratios.

- A new discrete fracture simulator with flexible and unstructured gridding techniques was developed to accurately model the fluid flow through fracture networks with multiple orientations.

**Field Demonstration of Carbon Dioxide Miscible Flooding in the Lansing-Kansas City Formation, Central Kansas**
**Contract**: DE-FC26-00BC15124
**Performer**: University of Kansas, Kansas Geological Survey
**Project Dates**: 3/8/2000 – 3/7/2010
**Objectives**: Determine the economic and technical feasibility of using $CO_2$ miscible flooding in an EOR project to recover residual and bypassed oil in the Lansing-Kansas City Field in central Kansas.
**Results**: Initial studies of the Lansing-Kansas City carbonate reservoir have determined the technical and economic feasibility of using $CO_2$ miscible flooding to recover residual and bypassed oil in central Kansas. The demonstration is the first time that $CO_2$ from an ethanol plant has been used for EOR. The project offers potential to add significant value to waste $CO_2$ through EOR. The $CO_2$ from the ethanol plant was being vented into the atmosphere before the start of this project.

$CO_2$ flooding began in December 2003. The $CO_2$ was trucked 7 miles from the ethanol plant in Russell, KS, and injected into the depleted Lansing-Kansas City reservoir. If the technology is economically feasible and applied to other Kansas fields, the estimated incremental oil production in the state of Kansas is 100-600 million barrels over 20 years. The pilot covers half of a traditional 5-spot pattern on 10 acres with one central injector, three producers, and two water injection containment wells. $CO_2$ breakthrough and the first incremental oil production began in May 2004.

By the end of June 2005, about 16.92 million pounds of $CO_2$ had been injected. The average rate of $CO_2$ injection for the previous six months was about 245,000 cubic feet per day. The initial production was 100% water, with oil arriving in February 2004. Oil rates averaged 3.8 barrels per day during January–June 2005. Incremental oil production was 1,494 barrels. Since then, neither production well has experienced increased daily oil production rates expected with the arrival of the oil bank. The volume of $CO_2$ produced had remained low, with gas/oil ratios on the order of 4,000-5,000. The amount of gas produced was 4.97 million standard cubic feet, which is about 3.4% of the injected $CO_2$. Injection was converted to water on June 21, 2005, in an effort to reduce operating costs to a breakeven level, with the expectation that sufficient $CO_2$ has been injected to displace the oil bank to the production wells by water injection.
$CO_2$ flooding demonstrated in this project may prevent up to 6,000 mature oilfields in Kansas from being abandoned. The potential target for $CO_2$ flooding in Kansas may total over 250-500 million barrels of incremental oil, equivalent to 5-10 years of additional Kansas production. The project's original objective, to demonstrate to Kansas independents the feasibility of $CO_2$ flooding and to find a viable supply of $CO_2$, is being met by joint industry ventures. This will benefit agriculture, ethanol production, and electrical generation in addition to independent oil producers. At the same time the public will gain the environmental benefit of less $CO_2$ in the atmosphere.

The electrical co-generation, ethanol production, and EOR project is unique in that it brings together three distinctly separate industries in a way that improves the economics of each while also providing a mechanism for value-added geologic sequestration of $CO_2$. If the full $CO_2$ stream from the ethanol plant is utilized for EOR for a 10-year period, the benefits from the three industry linkages would total $88 million.

As of 2006, the $CO_2$ project used only 10% of the $CO_2$ produced from the ethanol plant. Hall-Gurney field could use the full $CO_2$ output of five similar-sized ethanol plants at full-field $CO_2$ EOR development.

**4-D High-Resolution Seismic Reflection Monitoring of Miscible $CO_2$ Injected into a Carbonate Reservoir**
**Contract**: DE-FC26-03NT15414
**Performer**: University of Kansas Center for Research
**Project Dates**: 9/1/ 2003 – 8/31/2009
**Objectives**: Seismically delineate the non-linear movement of a miscible $CO_2$ floodbank through a thin carbonate petroleum reservoir with sufficient resolution to identify reservoir heterogeneities and their influence on sweep uniformity and efficiency.
**Results:** This project was designed to address questions related to both EOR flood management and $CO_2$ sequestration in mature, shallow, and thin carbonate reservoirs. Important aspects related to flood management include delineating preferential $CO_2$ pathways, enhancing sweep efficiency, locating areas of bypassed oil, and defining the mechanisms controlling $CO_2$ movement. As a secondary component, assessing the feasibility of this methodology for applications in $CO_2$ sequestration included identifying preferential pathways for $CO_2$ movement, delineating features that might influence long-term containment of $CO_2$, detecting movement of $CO_2$ outside containment at a high enough resolution to provide the necessary public assurances, and defining the minimum survey requirements for effective long-term monitoring.

Efficiency of EOR programs relies heavily on accurate reservoir models. Movement of miscible $CO_2$ injected into a thin (~5 meters), shallow-shelf, oomoldic carbonate reservoir around 900 meters deep in Russell County, KS, is being monitored successfully with high-resolution 4-D time-lapse seismic techniques. High-resolution seismic methods show great potential for incorporation into $CO_2$ flood management, thus highlighting the necessity of frequently updated reservoir-simulation models, especially for carbonates. Use of an unconventional approach to acquisition and interpretation of the high-resolution time-lapse/4-D seismic data was key to the success of this monitoring project. Twelve 3-D seismic reflection surveys will be conducted over 6 years to develop and refine appropriate methodologies for monitoring the injection and containment of miscible $CO_2$ in a thin carbonate reservoir in central Kansas.

Differences interpreted on consecutive time-lapse seismic horizon slices are consistent with $CO_2$ injection volumetrics, match physical restraints based on engineering data and model amplitude response, and honor production data. Textural characteristics in amplitude envelope images appearing to correspond to non-uniform expansion of the $CO_2$ through the reservoir honors both the lineaments identified on baseline data and changes in containment pressures. Interpretations of a set of time-lapse seismic images can be correlated to a mid-flood alteration of the injection/production scheme intended to improve containment and retard excessive northward movement of the $CO_2$.

The injection of $CO_2$ was halted, and water injection began as part of a water-alternating-gas scheme in July 2005. At that time, seven 3-D surveys had been completed (six monitor and one baseline) within about 18 months. The first monitor survey after water injection was conducted in January 2006. Based on flood simulations, water injection should severely alter the pressure and fluid distribution across the entire field within six months. Results from the January 2006 survey should provide uniquely different images of the reservoir relative to the last year of $CO_2$ injection.

**Evaluation and Enhancement of Carbon Dioxide Flooding Through Sweep Improvement**
**Contract**: DE-FC26-04NT15536
**Performer**: University of Oklahoma
**Project Dates**: 10/1/2004 – 9/30/2007
**Objectives**: This research is studying the effectiveness of carbon dioxide (CO2) flooding in a mature reservoir to identify and develop methods and strategies to improve oil recovery in CO2 floods. The objective of the project is to develop a methodology for improving sweep efficiency and reducing CO2 utilization rates by performing a detailed post-mortem on a mature CO2 project that relates actual reservoir performance with predicted performance. Knowledge gained from this detailed analysis will yield improved operating practices that will serve as a guide to improving oil recovery in active CO2 floods and as a strategy for implementing new CO2 floods.
**Results**: The study of Little Creek field identified strategies to improve recovery from the reservoir through understanding conformance control and sweep in the current operations. Based on the knowledge gained during this study, methods were developed for predicting conformance control and sweep efficiency that can be extended to other $CO_2$ injection projects, in progress or planned, and ultimately yield improved oil recoveries due to $CO_2$ flooding and reduce $CO_2$ utilization rates.

An historical evaluation of sweep efficiency in the Little Creek $CO_2$ flood was conducted. Performance predictions from reservoir simulations were compared with actual historical performance data, including displacement studies, conformance issues, and sweep efficiency. Laboratory displacement studies were conducted to correlate actual reservoir performance to simulation and laboratory studies for $CO_2$ flooding. A simulation exercise was used to match historical reservoir performance prior to the initiation of the $CO_2$ flood in order to develop a dynamic reservoir model for use in predicting performance based on actual reservoir conditions.

The reservoir model developed can be extended to reservoirs that may be $CO_2$ flooding candidates. Laboratory studies of $CO_2$ displacement of heavy oils conducted can be used to improve the confidence of recovery estimates made for this application. The studies are expected to yield an improved understanding of the feasibility of $CO_2$ flooding heavy oil reservoirs, obstacles that need to be overcome, and potential solutions to those obstacles.

**The Synthesis and Evaluation of Inexpensive $CO_2$ Thickeners Designed by Molecular Modeling**
**Contract**: DE-FC26-04NT15533
**Performer**: University of Pittsburgh
**Project Dates**: 9/10/2004 – 8/31/2007
**Objectives**: Use molecular modeling and experimental results to design inexpensive, environmentally benign, $CO_2$-soluble compounds that can decrease the mobility of $CO_2$ at typical enhanced oil recovery (EOR) reservoir conditions.
**Results**: The first $CO_2$ thickener, poly(fluoroacrylate-styrene), or polyFAST, in the laboratory was designed. PolyFAST remains the only $CO_2$ thickener that has ever been reported (DE-FC26-01BC15315). Although this project proved that a thickening agent could be designed for $CO_2$, it was not a practical thickener for field application. Specifically, PolyFAST was expensive, biologically and environmentally persistent, and not available in large volumes. All of these negative attributes were directly the result of the polymer having a high content of fluorine.

A second project (DE-AC26-98BC15108), also funded by DOE, researched inexpensive polymers that could dissolve in carbon dioxide and increase its viscosity, thereby improving mobility control of $CO_2$ floods. The project evaluated numerous polymers that contained no fluorine for this $CO_2$ thickening application. Specific chemical groups that were known to have a strong and favorable interaction with $CO_2$ were selected for study. The research identified the most $CO_2$-soluble, high-molecular-weight, commodity polymer that has yet been reported: poly (vinyl acetate), or PVAc. Unfortunately, the pressure required to dissolve PVAc in $CO_2$ was much greater than the range of the pressures used in most $CO_2$ floods.

Molecular modeling was used to design polymers that are more $CO_2$-soluble than PVAc, will dissolve below the minimum miscibility pressure (MMP), and will generate a two- to ten-fold decrease in $CO_2$ mobility at concentrations of 0.01–1.0 percent by weight. Although most of the thickeners envisioned are copolymers, researchers also evaluated several small hydrogen-bonding agents and surfactants with oligomeric (very short polymer) tails that form viscosity-enhancing structures in solution.

Three steps were required to accomplish the project goals. First, a highly $CO_2$-philic, hydrocarbon-based monomer was identified. Polymers or oligomers (small polymers) of this monomer must exhibit high $CO_2$ solubility at EOR MMP conditions. Second, the molecular weight of a homopolymer of the $CO_2$-phile must be increased as much as possible without causing the polymer to become insoluble in $CO_2$. Finally, a small concentration of a $CO_2$-phobic moiety that promotes viscosity-enhancing macromolecular interactions while not substantially diminishing $CO_2$ solubility must be incorporated into the polymer.

The research group successfully designed the first $CO_2$-soluble ionic surfactants that are highly soluble in $CO_2$. The most promising surfactant has a structure similar to the widely used commercially surfactant Aerosol OT, but the hydrocarbon tails have been replaced with oligomers (short polymers) of PVAc.

Most of the team’s work focused on the use of chemical groups with carbon, hydrogen, and oxygen, such as the acetate group, to enhance $CO_2$ solubility. Researchers also have found that tert-butyl groups, which are composed solely of carbon and hydrogen, also impart $CO_2$ solubility to compounds. They have established this trend for small, non-polar compounds and ionic surfactants and hope to determine whether the t-butyl group can increase the $CO_2$ solubility of polymeric compounds. The inclusion of the simple t-butyl group into compounds may be an inexpensive and easy way to induce $CO_2$ solubility.

The project has resulted in the:

- Successful use of *ab initio* calculations to design polymers. Researchers identified two monomer groups that exhibit stronger interactions with $CO_2$ than with vinyl acetate.
- Synthesis of poly(3-acetoxy oxetane), or PAO, and polymethoxy methyl ether, or PMME. Project performers were able to synthesize and characterize low-molecular-weight versions of both PAO and PMME and expect to test their $CO_2$ solubility soon.
- Synthesis of $CO_2$-soluble ionic surfactants. Researchers synthesized the first non-fluorous $CO_2$-soluble ionic surfactant by using short PVAc “tails” and are to test its ability to reduce mobility soon.

**Application of Time-Lapse Seismic Monitoring for the Control and Optimization of $CO_2$ Enhanced Oil Recovery Operations**
**Contract**: DE-FC26-03NT15425
**Performer**: Schlumberger Data and Consulting Service

**Project Dates**: 3/1/2004 – 2/28/2008
**Objectives**: This project was conducted in two phases. The objective of the first phase was to characterize the reservoir using advanced evaluation methods in order to assess the potential of a $CO_2$ flood of the target reservoir. This reservoir characterization includes advanced petrophysical, geophysical, geological, reservoir engineering, and reservoir simulation technologies. The objective of the second project phase was to demonstrate the benefits of using advanced seismic methods for the monitoring of the $CO_2$ flood fronts.
**Results**: The project has established a mappable correlation between low instantaneous frequency and high porosity. This relationship has been supported by the wave number study conducted with the depth volume. This relationship will be tested in the near future when a new borehole will be drilled into the reef. Once its location has been determined the porosity the borehole will encounter will be predicted with this technique. Should this relationship be proved, it will allow the porosity distribution through these reefs to be mapped accurately. Reservoir simulations needed to optimize the field's $CO_2$ injection parameters then can incorporate seismically detected porosity volumes to predict $CO_2$ migration in carbonates. If it is confirmed that instantaneous frequency can be used to accurately predict the distribution of >5% porosity through-out these reefs, this will allow for highly accurate reservoir simulations and greater reserve recoveries, thereby resulting in the most optimized enhanced oil recovery (EOR) projects possible. Monitoring of $CO_2$ floods will result in the ability to modify the injection parameters to recover more oil and sequester more $CO_2$.

## *Thermal Recovery*

**Heavy and Thermal Oil Recovery Production Mechanisms**
**Contract**: DE-FC22-00BC15311
**Performer**: Stanford University
**Project Dates**: 9/1/2000 – 12/31/2003
**Objectives**: (1) Investigate the mechanisms and factors that control the recovery of heavy oil under primary and enhanced modes of operation; and (2) provide the technical underpinnings needed to improve reservoir recovery efficiencies.
**Results**: The project laid the technical foundations for thermal oil recovery from low-permeability, fractured porous media as well as primary heavy oil recovery using the solution gas drive mechanism. Additionally, *in situ* upgrading of heavy oil was shown to be feasible using in situ combustion. The project also examined the efficiency of reservoir heating using horizontal and multilateral wells. Finally, improved reservoir definition techniques were developed to infer reservoir heterogeneity from production data. This project furthered the application of steam injection by lending support to the technical case for thermal recovery from low-permeability fractured formations, such as diatomite. Diatomite formations in California alone contain 12-80 billion bbl of original-oil-in-place (OOIP), and steam successfully unlocks these resources. Several companies are moving ahead with steam injection pilots and projects in diatomite partially as a result of this research.

**Experimental Investigation and High-Resolution Simulator of In-Situ Combustion Processes**
**Contract:** DE-FC26-03NT15405
**Performer**: Stanford University
**Project Dates**: 9/1/2003 – 8/31/2007
**Objectives**: (1) work in conjunction with the Technical University of Denmark to experimentally examine the dynamics of combustion and how they may be altered beneficially; and (2) develop

process simulation methodologies and capabilities that resolve in-situ combustion dynamics accurately.
**Results**: A new simulation tool was designed. It is based on an efficient Cartesian Adaptive Mesh Refinement (AMR) technique that allows much higher grid densities to be used near typical fronts than current simulators do. AMR reduces the dependency on grid size and empirically determined sub-grid scale models and allows a more accurate representation of the physics. This serves as a foundation for the development of a three-dimensional simulator that can handle realistic reservoir permeability heterogeneity.

Stanford has developed an upscaling method that not only ensures consistency between coarse- and fine-scale models but also uses aggressive adaptation to produce a coarse-scale model that contains far fewer grid points than would be required when using a Cartesian grid to achieve the same accuracy during simulation. The approach of tightly integrating adaptivity with upscaling is particularly well-suited to compositional and non-isothermal recovery methods, which involve several coupled physical processes with a wide range of characteristic spatial and temporal scales. The increased understanding of in-situ combustion dynamics and development of a simulator is expected to allow optimum design and execution of in-situ combustion recovery methods.

**Transformation of Resources to Reserves: Next-Generation Heavy Oil Techniques**
**Contract**: DE-FC26-04NT15526
**Performer**: Stanford University
**Project Dates**: 10/1/2004 – 9/30/2007
**Objectives**: (1) Improve understanding of primary and thermal heavy oil recovery mechanisms so that recovery efficiency increases and heavy oil that is not producible by conventional means becomes accessible; and (2) provide the technical understanding required to bring more heavy oil reservoirs under economic production.
**Results**: Achievements and successes include: (1) A review of the knowledge base with respect to thermal well completions that finds significant technology is available for development in cold environments; (2) development and validation of a semi-analytical model for cyclic steaming in horizontal wells; (3) understanding of the role that hydraulically fractured wells might play in thermal recovery processes; (4) experiments that analyzed foam generation mechanisms in micromodels reinforcing prior work that asserted snap off as a dominant foam generation mechanism; and (5) chemical analysis of heavy and viscous oils which display considerable variation in acid and base numbers. These differences appear to be indicators of oils that present favorable recovery characteristics by heavy oil solution gas drive.

**Investigation of Multiscale and Multiphase Flow, Transport and Reaction in Heavy Oil Recovery Processes**
**Contract**: DE-FC22-99BC15211
**Performer**: University of Southern California
**Project Dates**: 5/9/1999 - 1/5/2003
**Objectives**: Conduct research to provide a fundamental understanding of displacement efficiency directed toward foamy oil production, in situ drive, in situ combustion, steam foams, and the effect of heterogeneity on heavy oil recovery.
**Results**: Pore network simulations were conducted to study the liquid-to-vapor phase change that takes place during foamy oil production and in situ steam drive processes. A theoretical study was conducted to determine the effects of permeability heterogeneity at macroscopic scale on the propagation of thermal fronts in porous media to provide novel methods for upscaling. Properties of steam foams were investigated and the relative permeabilities of flowing foams in porous media were characterized. Mass transfer within pore networks was modeled.

## *Heavy Oil*

**Development of Shallow Viscous Oil Reserves on the North Slope**
**Contract**: DE-FC22-01BC15186
**Performer**: University of Houston
**Project Dates**: 9/26/2001 – 9/25/2004
**Objectives**: Develop tools to find optimum solvents, injection schedules, and well architecture for a water-alternating-gas (WAG) oil recovery process for the Alaska North Slope's shallow, viscous oil reservoirs.
**Results**: The results of the research established the EOR methods that will yield the greatest recovery from the North Slope's heavy oil reservoirs. It determined that: (1) Carbon dioxide injection works better than injection of Prudhoe Bay natural gas liquids (NGL); (2) Simulation modeling demonstrated the best strategy for timing and volume of WAG floods;( 3) Although sweep efficiency may decrease somewhat, horizontal wells were found to deliver more heavy oil than vertical wells. The factors that influence horizontal well performance were identified and can be used to plan horizontal wellbores and predict recovery; and (4) the use of electromagnetic heating of the reservoir can double the recovery of heavy oil. The technologies and strategies for heavy oil recovery developed by the project to optimize production through WAG injection via horizontal wellbores will significantly increase heavy oil production.

## *Chemical Flooding*

**Cost Effective Surfactant Formulations for Improved Oil Recovery in Carbonate Reservoirs**
**Contract**: DE-FC26-01BC15521
**Performer**: California Institute of Technology
**Project Dates**: 10/1/2004 – 9/30/2007
**Objectives**: Develop cost-effective chemical formulations to recover incremental oil beyond water-flood operations in carbonate reservoirs.
**Results**: Studies indicate that the more hydrophobic naphthenic acids (NA) have a greater effect on inducing oil-wet conditions. This work also suggests the wetting effect is independent of the binding energy of a NA on a carbonate surface. Laboratory results demonstrated that some surfactants can recover by imbibition (simple soaking treatments) more than 40% of this crude oil initially saturating 20 md limestone cores. These same successful surfactants are shown to be compatible with synthetic field brine (approximately 3 wt% salinity) at reservoir temperature. Analyses of different surfactants and wettability data have provided a selected suite of surfactants tested for their ability to recover crude oil via imbibition from limestone cores

**Behavior of Surfactant Mixture at Solid/Liquid and Oil/Liquid Interface in Chemical Flooding Systems**
**Contract**: DE-FC26-02NT15312
**Performer**: Columbia University
**Project Dates**: 9/1/2001- 8/31/2004
**Objectives**: Develop a knowledge base to help the design of enhanced processes for mobilizing and extracting untapped oil.
**Results**: The adsorption and aggregation behavior of sugar-based surfactants and their mixtures with other types of surfactants were studied to delineate the relationships between aggregate structures and chemical compositions of the surfactants and gain a full knowledge of the aggregate shape, size and structure, due to the important role played by these aggregates in governing the crude oil removal efficiency.

**Mineral-Surfactant Interactions for Minimum Reagents Precipitation and Adsorption for Improved Oil Recovery**
**Contract**: DE-FC26-03NT15413
**Performer**: Columbia University
**Project Dates**: 9/30/2003 – 9/29/2006
**Objectives**: Understand the role of mineralogy of reservoir rocks in determining interactions of reservoir minerals and their dissolved species with externally add reagants (surfactants/polymers), and their effects on solid-liquid and liquid-liquid interfacial properties such as adsorption, wettability, and interfacial tension and devise schemes to control these interactions in systems relevant to reservoir conditions.
**Results**: The study of interactions between typical reservoir minerals (quartz, alumina, calcite, dolomite, kaolinite, gypsum, pyrite, etc.) and surfactants/polymers has increased the understanding of rock-fluid interactions in oil reservoirs. Predictive models were developed that included minerals, surfactants/polymers, and reservoir conditions such as temperature and salinity. A guide-line for the use of surfactants/polymers in enhanced oil recovery was developed from these models.

Benefits from the projects included: (1) findings that provide valuable information for the study of mechanisms of Improved Oil Recovery (IOR) by chemical flooding and for the utilization of surfactant mixture systems in IOR by means of synergistic/antagonistic micellization and adsorption properties; and (2) new data on interactions between typical reservoir minerals (quartz, alumina, calcite, dolomite, kaolinite, gypsum, pyrite, etc.) and surfactants/polymers. This has increased the understanding of rock-fluid interactions in oil reservoirs. Predictive models have been developed that included minerals, surfactants/polymers, and reservoir conditions such as temperature and salinity. A guide-line for the use of surfactants/polymers in enhanced oil recovery is being developed from these models.

**Altering Reservoir Wettability to Improve Production from Single Wells**
**Contract**: DE-FC26-01NT15527
**Performer**: Correlations Company
**Project Dates**: 10/1/2004 – 9/30/2006
**Objectives**: Develop a surfactant soak technique in order to improve oil recovery by increasing the water-wettability of less than water-wet formations.
**Results**: The work on several research and field demonstration projects by Correlations was based on previous work by the PI at New Mexico PRRC. Technology developed for the Phosphoria formation in Wyoming was adapted to the San Andres formation in the Permian Basin. Laboratory techniques developed during the course of an SBIR (Small Business Research Innovation) project that focused on the Phosphoria formation were extended to include the San Andres formation. Artificial intelligence (AI) correlations developed during the SBIR project were used to design surfactant soak treatments in the San Andres formation of the Fuhrman-Masho field near Andres, TX. AI techniques were developed to establish baseline production trends in order to evaluate San Andres formation surfactant soak treatments in conjunction with the water-frac stimulation process.

Surfactant soaks field experiments were completed in 2006 in the Fuhrman-Masho (San Andres) pool in west Texas. During 2006, high-temperature imbibition tests were run with Stoney Mountain, Red River, Arbuckle, and Interlake cores and fluids at ConocoPhillips Reservoir Mechanisms Section high-temperature laboratory facilities in Bartlesville, OK. Low-cost surfactant soak stimulation treatments will prolong the life of marginally economic wells in oil-wet reservoirs that contain about 22% of the Nation's domestic original-oil-in-place. Most of such reservoirs are oil-wet, heterogeneous, and naturally fractured, and are therefore ideal candidates for the surfactant soak process. An estimated 100,000 of the Nation's 500,000 domestic producing oil wells could benefit from surfactant soak technology.

**Improved Approaches to Design Polymer Gel Treatments in Mature Oil Fields: Field Demonstration in Dickman Field, Ness County, KS**
**Contract**: DE-FC26-03NT15438
**Performer**: Grand Mesa Operating Co.
**Project Dates**: 8/12/2003 – 10/312004
**Objectives**: Accelerate adaptation and evaluation of new technologies, such as gelled polymer technology, specifically for decreasing water production in producing wells through collaboration among independent producers and service companies operating in Kansas.
**Results**: A polymer gel treatment was conducted and performed successfully. This is the first large-scale gel polymer field test of a Mississippian carbonate reservoir in Kansas. Representative samples of cross-linked polymer solution were collected during all treatment stages to ensure that the intended gels ultimately would form. Pre-gel samples were stored at a temperature of 120° F. in an oven onboard the TIORCO portable polymer injection unit. All samples indicated that gels formed as intended.

The project benefits stem from demonstrating the feasibility of polymer gel technology to increase the recovery of reserves from Mississippian reservoirs in Kansas. The increase in recoverable reserves was accomplished by (1) reducing water production from Mississippian producers and the well operating cost; (2) increasing the drawdown on Mississippian producers while boosting oil production and remaining recoverable reserves; and (3) enabling uneconomic producers to be returned to production.

**Microbial Enhanced Oil Recovery-Surfactant from Waste Products and Biotechnologies for Oilfield Application**
**Contract**: FEW5AC312
**Performer**: Idaho National Engineering Laboratory (INEL)
**Project Dates**: 3/7/1989 – 3/14/2004
**Objectives**: Research more cost effective and environmentally acceptable methods of microbiologically based enhanced oil recovery.
**Results**: INEL's Biotechnology for Oilfield Operations program supported the development, engineering and application of biotechnology for exploration and production of petroleum as well as the mitigation of detrimental field conditions.

INEL successfully produced surfactant from potato process effluents for possible use as an economical alternative to chemical surfactants for improving oil recovery. Research at the INL demonstrated the feasibility of producing surfactant in cultures of *Bacillus subtilis* grown on soluble starch as well as the utility of applying biosurfactants to IOR. The project also demonstrated the ability to produce surfactant from agricultural process effluents, described the impact of effluent pretreatment, and evaluated the application of novel reactor configurations for production and separation from actual process effluents. Program execution enabled and initiated technical growth into other important areas in research projects at the University of Tulsa, ConocoPhillips; Texaco; New Mexico PRRC, U. of Wyoming; Montana State University: Halliburton; and the University of Kansas.

**Surfactant-Based Enhanced Oil Recovery Processes and Foam Mobility Control**
**Contract**: DE-FC26-03NT15406
**Performer**: Rice University

**Project Dates**: 6/10/2003 – 9/9/2006
**Objectives**: (1) Develop new cost-effective surfactants and processes; (2) present a mechanistic understanding of how these processes work; and (3) develop simulation tools to scale-up the processes for field application.
**Results**: A surfactant-polymer formulation was developed for a West Texas carbonate reservoir that has a pressure too low for $CO_2$ flooding. The formulation has recovered up to 95% of the oil remaining after waterflooding in reservoir formation core material. The oil-wet character of the crude oil/brine/rock system was such that an oil saturated core placed under formation brine did not recover any oil by spontaneous imbibition. However, when the brine was replaced by an alkaline surfactant solution, oil was spontaneously displaced by gravity drainage. The alkaline surfactant solution both alters wettability and reduces interfacial tension to ultralow values. Thus it overcomes the capillary retardation forces and permits the oil to flow by buoyancy or gravity drainage.

INEL develops surfactant EOR processes for companies that do not have in-house research capability. The oil recovery from laboratory experiments for the surfactant-polymer process is far greater than the best recovery achieved by a vendor contracted by the operator. Development of efficient EOR processes and making the knowledge available to the industry will result in increased oil recovery from the mature oil reservoirs that are nearly depleted by conventional waterflooding.

**Dilute Surfactant Methods for Carbonate Formations**
**Contract**: DE-FC26-02NT15322
**Performer**: University of Houston
**Project Dates**: 6/24, 2002 – 11/23/2005
**Objectives**: Evaluate dilute (hence relatively inexpensive) surfactant methods for carbonate formations and identify conditions under which they can be effective.
**Results**: Surfactants have been identified that alter wettability of calcite minerals aged with a crude oil and that lower interfacial tension. Surfactant adsorption can be minimized by the use of an alkali. Laboratory imbibition tests show about 61% oil recovery with an anionic surfactant and 37% in the case of a cationic surfactant. A numerical model has been developed that fits the rate of imbibition of the laboratory experiments. Field-scale fracture-block simulation shows that as the fracture spacing increases, so does the time of recovery.

The waterflood recovery in fractured carbonate reservoirs is typically very low. This dilute surfactant method can be used to improve the oil recovery in high-permeability reservoirs by almost 60%. The key mechanism for oil recovery in this process is the improvement of oil relative permeability due to wettability alteration. As the surfactant is transported into the matrix, it decreases interfacial tension and contact angle, capillary pressure decreases, and oil relative permeability increases. Gravity helps the oil to flow to the top, and oil is recovered as the surfactant solution imbibes in from the bottom. Fracture spacing and block height affect the recovery rate at the field scale. The chemical cost was estimated to be 50 cents per barrel of oil recovered for one field scenario.

**Using Biosurfactants Produced from Agriculture Process Waste Streams to Improve Oil Recovery in Fractured Carbonate Reservoirs**
**Contract**: DE-FC26-04NT15523
**Performer**: University of Kansas
**Project Dates**: 10/1/2004 – 9/30/2007
**Objectives**: Evaluate the use of low-cost biosurfactants produced from agriculture process waste streams to improve oil recovery in fractured carbonate reservoirs.

**Results**: Interfacial tension of a range of surfactants with Soltrol 130 was determined using a ring tensiometer. Two-phase rapid wettability tests were used to confirm that one of the sample rocks (Miami oolite) could be rendered water-wet by use of an intricate cleaning process, and that the same material could be made oil-wet by aging in crude oil at elevated temperature. Five different core materials, covering a range of porosity, permeability, and pore architecture have been characterized using gravimetric, tracer and nuclear magnetic resonance techniques (the latter at ConocoPhillips in Bartlesville, OK). Static adsorption tests were carried out using crushed core materials and a range of concentrations of benchmark surfactants. A surfactant-ion selective electrode was used to detect the endpoint in potentiometric titrations of the anionic surfactants.

The successful completion of the project led to a method to significantly increase domestic oil production by recovering previously unrecoverable stranded oil and promote the beneficial reuse of agriculture process waste products. It ensures a continued income for operators of established fields and makes possible the exploitation of previously uneconomic reserves. In addition, the production of biosurfactant will provide a use for high-BOD (biochemical oxygen demand) agriculture process stream waste, with benefits for both the operators and the environment.

**Smart Multifunctional Polymers**
**Contract**: DE-FC26-03NT15407
**Performer**: University of Southern Mississippi
**Project Dates**: 9/30/2003 – 3/31/2007
**Objectives**: Synthesize, characterize, and evaluate stimuli-responsive polymer systems that can be formulated into "smart" fluids with rheological and interfacial properties substantially superior to those currently available for EOR with chemical (micellar) flooding.
**Results**: The new "smart" copolymers developed can control fluid mobility and/or conformance in oil recovery processes by altering viscosity and/or permeability using triggers based on pH, salt or temperature variations. The polymer systems developed may demonstrate superior performance as mobility control agents in micellar enhanced EOR processes due to surfactant-induced viscosity enhancement. The "smart" polymers are designed to have "triggerable" properties such as changes in pH and/or salt concentration, which enable them to react to reservoir conditions to stimulate increased oil flow.

The project resulted in the synthesis of several novel chain-transfer agents (CTAs), which has enabled the controlled polymerization of stimuli-responsive polymers with complex architectures allowing for the formation of unimeric and multimeric micelles. These copolymers have been characterized with regard to molecular weight and composition..

Although a number of small molecule surfactants have been utilized for micellar EOR, stimuli-responsive polymeric surfactants have not been tested in the field or the laboratory for advanced recovery. Researchers recently have shown the remarkable ability of polymeric surfactants responsive to pH and temperature to reversibly sequester model compounds, including tetradecane, naphthalene, and *p*-cresol. Unlike small-molecule surfactants, unimeric polysoaps do not require concentrations above the cmc (critical micelle concentration) for sequestration of hydrocarbons, because each polymer contains intramolecular domains. The hydrophobically modified polymeric surfactants can undergo reversible polysoap-to-extended-coil transitions, depending upon conditions. Unimeric or multimeric micelles can be generated in response to pH, ionic strength, or temperature. Surface activity and thus oil mobilization and emulsification can, in theory, be reversibly manipulated. Developing "smart" fluids with properties superior to those currently available for chemical flooding can greatly improve sweep efficiency and thereby bolster the cost-effectiveness of chemical EOR projects.

**Modeling Wettability Alteration Using Chemical EOR Processes in Naturally Fractured Reservoirs**
**Contract**: DE-FC26-04NT15529
**Performer**: University of Texas at Austin
**Project Dates**: 10/1/2004 – 9/30/2007
**Objectives**: Develop a simulation tool to improve the understanding of multiphase surfactant, alkaline, hot water, or surfactant enhanced oil recovery (EOR) processes in naturally fractured oil reservoirs with emphasis on innovative EOR processes that reduce the interfacial tension, reduce the mobility ratio, and enhance production by altering wettability.
**Results**: Two University of Texas projects started in the 1990s and continuing into the 2000s were related to development of an improved simulator for chemical and microbial IOR flooding, leading to the release of the UTCHEM 3-dimensional flood simulator for cost effective surfactant flooding.

Three earlier projects dealt with optimizing chemical floods, studies of improved foam processes, and wettability modeling for EOR processes in fractured reservoirs. The goal was to provide the scientific and engineering basis for improved design of foam processes for enhanced oil recovery, by studying polymer-enhanced foam, gas trapping in the presence of foam, and mechanisms of foam generation. Numerical models and simulation studies of foam mechanism were developed to improve prediction of foam movement through the reservoir. An area of unstable foam generation was identified that provided important information for foam design in field applications. This research provided the foundation for more-accurate predictive modeling of foam processes to improve oil recovery, improve process design, enable wider application of foams and gas injection, and increase domestic oil production.

A user-friendly and efficient platform called UT_IRSP was designed and successfully implemented. The reservoir simulators currently included in the framework are VIP of Halliburton, ECLIPSE of Schlumberger, and UTCHEM. The UT_IRSP approach is used in field-scale development design and optimization projects. An efficient approach has been developed and successfully implemented to obtain the optimum design under uncertainty for a wide range of reservoir simulation applications. This approach significantly reduces the time required to evaluate optimum designs for improved oil recovery processes.

Researchers have performed several surfactant flooding simulations with different permeability and permeability heterogeneities, surfactant concentration, and slug size to identify the key variables that control project life and oil recovery using the experimental design and a simple discounted cash flow analysis. The experimental design module was used to design the simulations varying the primary variables such as reservoir permeability and heterogeneity, surfactant and polymer concentration, and slug size and the provided range for each.

Researchers developed and implemented a model in UTCHEM to account for wettability alteration as the result of surfactant injection. The model presently takes into account the changes on the relative permeability and capillary desaturation curves. To date, researchers have: 1) Developed and implemented a preliminary model for wettability alteration in UTCHEM; 2) Performed field-scale simulations with different wettability conditions; and 3) Conducted surfactant flooding simulations in fractured reservoirs with wettability alteration.

The chemical simulator UTCHEM was upgraded by adding the capability of modeling wettability alteration during chemical EOR processes. This addition provides a unique simulator that can model surfactant floods in naturally fractured reservoirs by coupling wettability effects on relative permeabilities, capillary pressure, and capillary desaturation curves. This is a new and potentially very important application of simulation technology that has never been attempted despite the enormous volumes of oil remaining in naturally fractured reservoirs. Numerical simulations are needed to scale up and predict the performance of field-scale applications of chemical EOR. The upgraded compositional simulator resulting from this project is expected to enable the development of cost-effective chemical EOR processes because it can model surfactant phase behavior, temperature-dependent fluid properties, and wettability-dependent petrophysical properties in naturally fractured reservoirs. This simulator was the first to incorporate all of these features.

## *Polymer Gels*

**Using Chemicals to Optimize Conformance in Fractured Reservoirs**
**Contract**: DE-AC26-98BC15110
**Performer**: New Mexico Technological Institute
**Project Dates**: 9/29/98 - 9/30/2001
**Objectives**: Develop guidelines for using chemicals to optimize blocking agent performance in fractured reservoirs.
**Results**: The project: (1) developed, tested and proved a sound mechanistic model for gel extrusion through fractures (2) demonstrated the benefits of rapid injection during gel extrusion to maximize penetration along fractures; (3) developed software for sizing gelant treatments in hydraulically fractured production wells: and (4) investigated the mechanism for disproportionate permeability reduction using corefloods and imaging experiments using synchrotron x-ray microtomography.

**Conformance Improvement Using Gels**
**Contract**: DE-FC22-01BC15316
**Performer**: New Mexico Technological Institute
**Project Dates**: 9/01/01 - 11/30/2004
**Objectives**: (1) Identify gel compositions and conditions that substantially reduce flow through fractures that allow direct channeling between wells; and (2) optimize treatments in fractured production wells, where the gel must reduce permeability to water much more than that to oil.
**Results**: This project: (1) identified the mechanism for why some gels can reduce permeability to water more than to oil; (2) established the mechanism for propagation of formed gels in fractures and proposed a more credible mechanism for filter-cake formation in fractures; and (3) established a web site that allows anyone to view the state of the art in water-shutoff technology using gels.

**Aperture-Tolerant, Chemical-Based Methods to Reduce Channeling**
**Contract**: DE-FC26-04NT15519
**Performer**: New Mexico Technological Institute
**Project Dates**: 10/1/2004 – 9/30/2007
**Objectives**: (1) Develop aperture-tolerant, chemical-based methods to reduce channeling through voids (e.g., fractures, vugs, karst) during hydrocarbon production; (2) incorporate analyses of selected field applications to evaluate the efficacy and mechanism of action for different gel-treatment approaches; (3) develop materials that can be effectively placed and will consistently minimize flow through voids with a wide range of apertures; and (4) develop methods to minimize water entry into voids from the surrounding rock.

**Results**: New Mexico Technological Institute increased understanding the mechanisms by which gels reduce water and oil production has help increase the reliability of gel treatments during water-shutoff efforts in field applications. Researchers developed a web site that details many different types of water shutoff problems and provides a water shutoff strategy with relevant field examples and important information about the properties of polymers, gelants, and gels—what they can and cannot do, where and how gel treatments should (and should not) be placed, and how to assess the effectiveness of the gel treatment. Better performance of gels in shutting off water production in improved oil recovery (IOR) operations boosts oil production and ultimate reserves recovery while benefiting the environment through mitigating the handling and disposal of large volumes of produced water.

X-ray computed microtomography (XMT) was used to understand why gels reduce permeability to water more than that to oil. That work revealed that “strong” Cr(III)-acetate-HPAM gels formed in virtually all aqueous pore spaces. For normal pressure gradients, water injected after gel placement was forced to flow through the gel itself, experiencing microdarcy permeabilities. In contrast, even for relatively low-pressure gradients, oil injection destroyed gel or reduced the gel volume so as to enhance oil permeability (relative to water flow). During subsequent water flow (after oil flow and after gel placement), the gel trapped much higher levels of residual oil (relative to the $S_{or}$ before gel placement)—thus again providing a permeability to water that was much less than that to oil.

Aperture-tolerant, chemical-based methods were developed to reduce channeling through voids (e.g., fractures, vugs, karst) during hydrocarbon production. Analyses of selected field applications were conducted to evaluate the efficacy and mechanism of action for different gel-treatment approaches. Materials were developed that can be effectively placed and consistently minimize flow through voids with a wide range of apertures. Methods to minimize water entry into voids from the surrounding rock were developed.

Successful developments from this project provided substantial improvements over existing gel treatment technologies, whose reliability currently depends critically on the aperture of the void channel. The results from this work also could be applied to gas shutoff problems (e.g., $CO_2$ channeling) and to other enhanced oil recovery (EOR) processes where channeling of expensive injection fluids is a concern.

**Increased Oil Recovery from Mature Oil Fields Using Gelled Polymer Treatments**
**Contract**: DE-AC26-99BC15209
**Performer**: University of Kansas
**Project Dates**: 6/19/99 - 7/1/2002
**Objectives**: Improve the performance of polymer gels used in waterflooding mature reservoirs.
**Results**: A computer controlled x-y table was constructed and installed, and was used to determine *in situ* water saturations in rock slabs during gelation and post-gelation flow experiments. Results were obtained from a series of flow experiments in Berea sandstone cores and sandpacks. The interpretations of the experiments provide insights into the mechanisms by which a gel treatment reduces water production. Results were obtained on the stability of gels in fractures. Methods were developed to determine the molecular mass and size of aggregates from form in gel systems.
Water control in production wells is based on the two-phase flow characteristics of gelled polymer systems, which are strategically placed in the reservoir and then dehydrated to block the flow of water. The focus on in-depth injection treatment was the development of pre-gel aggregates, which form during the gelation process.

**Development of Polymer Gel Systems to Improve Volumetric Sweep and Reduce Producing Water/Oil Ratios**
**Contract**: DE-FC26-02NT15363
**Performer**: University of Kansas
**Project Dates**: 7/1/2002 – 12/31/2005
**Objectives**: Improve the effectiveness of polymer gels to increase volumetric sweep efficiency of fluid displacement processes and to reduce water production in production wells.
**Results**: Project researchers have accomplished the following: 1) development of a mathematical model that simulates polymer crosslinking processes, 2) kinetic study of the reaction between chromium acetate and polyacrylamide, 3) development of a mathematical model that simulates the transport of chromium acetate through carbonate rocks, and 4) experimental study of the effect of gelant composition and oil/water pressure gradients on disproportionate permeability reduction (DPR). The mathematical model and accompanied data describing the formation and growth of pre-gel aggregates is a major advancement in the fundamental understanding of the placement of gelants in oil reservoirs. Additionally, the role of carbonate dissolution on the in-depth propagation of gelants is more clearly known, and a mathematical model was developed to simulate the chemistry. These tools allow for the improvement of current gel systems and the development of new systems that can be applied in the field. Reduced water production from improved systems reduces operating costs for the oil producer and mitigates environmental concerns of large volumes of produced water. Lower operating costs extend the life of reservoirs, resulting in increased oil production.

## *Microbial EOR*

**Bio-Engineering High Performance Microbial Strains for MEOR by Directed Protein Evolution Technology**
**Contract**: DE-FC26-04NT15525
**Performer**: California Institute of Technology
**Project Dates**: 10/1/2004 – 9/30/2007
**Objectives**: (1) Apply advanced bio-engineering methods (such as genetic manipulation) to induce bacteria that naturally make biosurfactants do so at a much higher, commercially useful rate; and (2) implant the genetic information for rapid biosurfactant production into microbes adaptable in an oil reservoir environment.
**Results**: The researchers developed the laboratory techniques to create and evaluate mutated bacteria for their increased ability to make biosurfactants. The expected result is that these production rates will be orders of magnitude higher than the naturally occurring strains. Bio-based surfactant alternatives offer new (and perhaps better) choices for an EOR project. These chemicals are more environmentally friendly and can come from renewable resources. Oilfield or industrial chemicals may be created with bioprocesses that will produce a product that costs less and is environmentally friendly.

**Augmenting a Microbial Selective Plugging Technique with Polymer Flooding to Increase the Efficiency of Oil Recovery - a Search for Synergy**
**Contract**: DE-FC22-99BC15210
**Performer**: Mississippi State University
**Project Dates**: 4/26/99 - 4/25/2002
**Objectives**: Improve the selective redirection of reservoir fluid flow using combined microbial and polymer technologies.
**Results**: Chemical and microbiological characterization of eight polymers were completed. Of these, one was xanthan, six were polycrylamides, and the final one was a new product obtained

from the University of Kansas. Performance of the polymers was tested in the laboratory on Berea core plugs. Testing of the ability of the polymer solutions and the microbes to redirect flow in sandpacks was traced using radioactive manganese to track water flow through he sandpack. The sandpack experiments clearly showed that the polymer alters the path of water flow in the packs as dowse the growth of microorganisms. It was demonstrated that the path of water flow in a sandpack was altered by the polymer solution, and that after treatment with microbial nutrients, the path of water flow was altered further.

Work continued with core plugs from North Blowhorn Creek field in Alabama. Treatment of the core plugs with polymer prevented or greatly retarded the growth of the indigenous microflora. Other tests conducted with microbial nutrients added prior to the polymer solutions. Electron microscopic analysis showed that the indigenous bacteria in the core material produce copious quantities of polymer when supplemented with nitrate and phosphate. The method of preservation of core samples prior to examination was found to cause distortions and misinterpretations of the results. In some preparations, the initially described polymer "ball ups" were found to be nanobacteria. Successful development of a microbial/polymer combination will potentially provide oil producers with a synergistic, cost-effective process for oil recovery.

**Development of Microorganisms with Improved Transport and Biosurfactant Activity for Enhanced Oil Recovery**
**Contract**: DE-FC26-02NT15321
**Performer**: University of Oklahoma
**Project Dates**: 6/1/2002 – 5/31/2005
**Objectives**: (1) Develop microbial strains with improved biosurfactant properties that use cost-effective nutrients; (2) obtain biosurfactant strains with improved transport properties through sandstones; and (3) determine the empirical relationship between surfactant concentration and interfacial tension (IFT).
**Results**: Project researchers found that (1) diverse microorganisms produce biosurfactants; (2) nutrient manipulation may provide a mechanism to increase biosurfactant activity; (3) spore transport occurs at high efficiencies; (4) biosurfactant concentrations in excess of the critical micelle concentration recover substantial amounts of residual oil; and (5) equations that describe the effect of the biosurfactant on IFT adequately predict residual oil recovery in sandstone cores. The long-term economic potential for enhanced oil recovery (EOR) is large, with more than 300 billion barrels of oil remaining in domestic reservoirs after conventional technologies reach their economic limit. The U.S. DOE Reservoir Data Base contains listings for more than 600 reservoirs with over 12 billion barrels of currently unrecoverable oil that are potential targets for microbially enhanced oil recovery (MEOR). If MEOR could be successfully applied to reduce residual oil saturation by 10% in a fourth of these reservoirs, more than 300 million barrels of oil could be added to U.S. oil reserves.

## *Waterflooding*

**Economic Implementation and Optimization of a Secondary Oil Recovery Process: St. Mary West Cotton Valley Unit, Lafayette County, AR**
**Contract**: DE-FC22-00BC15254
**Performer**: Strand Energy
**Project Dates**: 7/1/2000 – 6/30/ 2006
**Objectives**: Provide successful economics in the operation of a secondary recovery project initiated late in the primary production phase, focusing on reducing injection system installation costs; reducing operating expenses during the fill-up period; and reducing the response time to increased production rates.

**Results**: Using a detailed reservoir model developed through current reservoir characterization practices, the project made a comparison study of the economic optimization of secondary oil recovery processes in a nearly primary depleted, Arkansas oil field to identify the process that provide the most efficient and least costly operation under field conditions.

Results included collection of reservoir and well bore injection performance data obtained during the pilot flood that provided important data for completing the reservoir model and optimization of the secondary recovery process. The pilot project also provided deliverability parameters for the shallow aquifer, important to determining if a full field flood, water source is available.

The secondary recovery water injection rates for the Unit were improved with the addition of a second injection well; hydraulic fracture of the reservoir sands in the injection wells has also been effective in improving injectivity. Reservoir and well bore injection performance data obtained during the pilot project was important to the secondary recovery optimization study. Daily water injection for the two pilot injection wells averaged 650 bopd. Early waterflood response was apparent in one producer located north of the reservoir injection site.

Pressure data from four well bores indicated that measured pressures were 1,000 psi higher than expected for the mature reservoir. This prospect of a significant pressure drive remaining in the reservoir prompted Strand to experiment with a sand propped hydraulic fracture stimulation in an idle well. A seven-fold increase in daily oil production was achieved; additional fracture treatments for the remaining producers were scheduled. Total daily oil production for the Unit was 38 bopd. A successful evaluation to choose the practical secondary recovery process appropriate for the St Mary West reservoir and the implementation of the project in the St Mary West field aided in the development of skills in the small independent population in the area.

**Production Improvement from Increased Permeability Using Engineered Biochemical Secondary Recovery Methodology in Marginal Wells of the East Texas Field.**
**Contract**: DE-FC26-03NT15440
**Performer**: TENECO Energy, LLC
**Project Dates**: 7/1/2003 – 12/31/ 2004
**Objectives**: (1) Test and evaluate a method for increasing oil production by implementing innovative technology using a multi-dimensional biochemical secondary recovery treatment engineered to remove permeability impediments, e.g. paraffin, asphaltene, inorganic scale, iron corrosion, and mobilize residual frac gels, etc., accumulated over the 70 year production history from the East Texas Field; and (2) devise a protocol that has the significant environmental advancement that no petroleum based solvents or additives are required; so that permits, remediation and spill cleanup are avoided.
**Results**: A combination of a regenerating biochemical mixture and an organic surfactant was applied to wells in the East Texas Field to restore permeability, reverse formation damage, mobilize hydrocarbons, and ultimately increase production. Initial work was designed to open the perforations and remove blockages of scale, asphaltene, and other corrosion debris. This was accomplished on three wells that produce from the Woodbine formation, and was necessary to prepare the wells for more substantial treatments. Two wells were treated with much larger quantities of the biochemical mixture, e.g. 25 gallons, with a 2% KCl carrier solution that carried the active biochemical solution into the near wellbore area adjacent to producing reservoir. After a 7 to 10 day acclamation and reaction period, the wells were put back into production. The biochemical solution successfully broke down the scale, paraffin and other binders blocking permeability and released significant debris, which was immediately produced into the flow lines and separators. Oil production was clearly improved and the removed debris was a maintenance issue until the surface equipment could be modified.

The permeability restrictions in a cylindrical area of 10 to 20 feet from the wellbore within the reservoir were treated with the biochemical solution. Fluid was forced into the producing horizon using the hydraulic head of the well filled with 2 % KCl solution, allowed to acclimate, and then withdrawn by pumping. The chloride content of the produce water was measured and production of oil and water monitored. The most significant effect in improving permeability and removing scale and high molecular weight hydrocarbons was accomplished in the wellbore perforations and near wellbore treatments. The effect of deeper insertion of the solution had minimal impact on production.

**Preferred Waterflood Management Practices for the Spraberry Trend Area**
**Contract**: DE-FC22-01BC15274
**Performer**: Texas A&M TEES
**Project Dates**: 12/1/2001 – 8/31/2004
**Objectives**: Design and test different waterflood techniques that have never been used in the Spraberry Trend Area.
**Results**: This PUMP project was a follow up on a Class III project by Pioneer Natural Resources in the Spraberry Trend. The new waterflood aligned injection wells along the fracture trend with production wells. One new injection well was drilled that was not artificially fractured to test whether specific zonal isolation is the primary key. Existing producers with massive hydraulic fracture treatments will be converted to injectors to test whether the hydraulic fractures hinder or aid sweep efficiency. An injection pattern, which is adjacent to, and on-trend with a section containing a majority of plugged wells were dedicated to investigating whether there is still mobile oil in the vicinity of old, abandoned wells and whether this oil can be swept and captured in current producing wells. A comprehensive analysis was provided to identify the preferred management practices and to transfer the information to all Spraberry operators so that other operators can initiate water injection based on the results of the Spraberry Germania Unit Field Demonstration.

The major achievements of the project were 1) provided an integrated solution to technological, regulatory, and data constraints in the Spraberry Trend area; 2) completed a field demonstration via technological innovations; 3) determined that converted production wells are not suitable for injection due to previous fracture treatments; and 4) stimulated investment in further waterflood projects in the Spraberry Trend area. Spraberry was once deemed the "largest uneconomic field in the world. Increased production from Spraberry wells led Pioneer Natural Resources to buy extensive additional leases in the Spraberry area and drill hundreds of new wells using the new waterflood technologies from the Class III and PUMP projects.

## *Simulation Models*

**Advanced Techniques for Reservoir Simulation and Modeling of Nonconventional Wells**
**Contract**: DE-FC22-99BC15213
**Performer**: Stanford University
**Project Dates**: 9/1/99 - 8/31/2004
**Objectives**: Develop innovative simulation tools to enhance the ability of reservoir engineers to model and optimize reservoir performance. The objectives were to develop innovative simulation tools.
**Results**: Significant progress was made on the development of key components of the general purpose flexible grid simulator. Algorithms allowing for a general treatment of multi-component systems were developed and tested. These included algorithms for the reservoir simulator, for gridding and upscaling and for the calculation of reservoir production index. Approaches for

including tensor permeabilities and grid non-orthogonality in the flow calculations were developed. Efficient tools were implemented for the calculation of well productivity for single phase flow for non-conventional wells operating downhole with inflow control devices. Procedures and correlations for estimating drift flux parameters for modeling two-phase flows were also developed.

**Investigation of Multiscale and Multiphase Flow, Transport and Reaction in Heavy Oil Recovery Processes**
**Contract**: DE-FC22-99BC15211
**Performer**: University of Southern California
**Project Dates**: 5/6/99 - 1/5/2003
**Objectives**: Conduct research to provide a fundamental understanding of displacement efficiency directed toward foamy oil production, in situ drive, in situ combustion, steam foams, and the effect of heterogeneity on heavy oil recovery. This project is discussed under both Thermal Recovery and Simulation because of the nature of the research and simulator tools developed to improve heavy oil recovery.
**Results**: The research was experimental using analytical and numerical methods. Pore network simulations were conducted to study the liquid-to-vapor phase change that takes place during foamy oil production and in situ steam drive processes. A theoretical study was conducted to determine the effects of permeability heterogeneity at macroscopic scale on the propagation of thermal fronts in porous media to provide novel methods for upscaling. Properties of steam foams were investigated and the relative permeabilities of flowing foams in porous media were characterized. Mass transfer within pore networks was modeled. Simulation models were developed for several aspects of stream drive heavy oil recovery.

**A New Generation Chemical Flooding Simulator**
**Contract**: DE-FC22-01BC15314
**Performer**: University of Texas at Austin
**Project Dates**: 9/1/01 - 8/31/04
**Objectives**: Develop a new-generation chemical flooding simulator capable of efficiently and accurately simulating oil reservoirs with at least a million gridblocks in less than one day on parallel computers.
**Results**: A fully implicit, parallel compositional reservoir simulator called GPAS was developed with the capability of both equation-of-state gas compositional and surfactant/oil/brine phase behavior. A simulation of over 1 million gridblocks of a surfactant/polymer flood was successfully performed using more than 100 processors. The project: 1) developed a fully implicit, parallel, compositional chemical flooding simulator and validated it against other simulators, 2) determined that the results of parallel runs are almost identical to those on a single processor, 3) showed that the simulator scales well using a cluster of workstations, and 4) successfully performed field-scale, high-resolution surfactant/polymer flood simulations with over 1 million gridblocks. There is a greater demand for parallel computing since the oil industry is requiring reservoir simulations with geological, physical, and chemical models of much more detail.

**History-Matching in Parallel Computational Environments**
**Contract**: DE-FC26-03NT15410
**Performer**: University of Texas at Austin
**Project Dates**: 9/1/2003 – 8/31/2006
**Objectives**: Develop a new numerical methodology for improved performance prediction of petroleum reservoirs.

**Results**: The strategy combined a stochastic approach for updating the underlying geological model of reservoir heterogeneity with a domain-decomposition technique for distributing the flow simulations across multiple processors. Researchers established a general procedure for gradually updating geological models within an assisted history-matching framework. A generic, simulator-independent method of estimating sensitivities via multiple realizations was developed and shown to perform as well as the principal-components analysis. Both methods are more robust ways to adjust permeabilities within the spatial domain. The researchers demonstrated this approach on a realistic 3-D test case. A functional prototype of middleware was tested. The middleware enables a user to apply the history matching algorithm in conjunction with any reservoir simulator. The goal of history-matching was to obtain a model of a reservoir from which reliable forecasts of future production can be obtained. History-matching—which entails choosing a large set of parameters (e.g., local permeability values) so that a small data set (e.g., well flow rates as a function of time)—is under-constrained. A solution to this problem that makes geological sense is more likely to provide reliable forecasts. The second guiding idea is that it must be possible to obtain insight from a computer implementation of the history-matching in a practical length of time (e.g., overnight). The time scale for decision-making in many industrial applications does not allow for lengthy calculations. History-matching is the most time-consuming aspect of any flow simulation project; organizations routinely dedicate several man-months of personnel time to the task. The procedure developed allows for automatic, scheduled jobs running in the background on whichever computing platforms are available, whether parallel or distributed.

**Parallel, Multigrid Finite Element Simulator for Fractured/Faulted and Other Complex Reservoirs Based on CCA**
**Contract**: DE-FC26-04NT15531
**Performer**: University of Utah
**Project Dates**: 9/9/2004 – 8/31/2007
**Objectives**: (1) develop reservoir simulators for complex fractured, faulted systems; (2) create thermal and compositional modules for fractured-faulted systems; and (3) develop new well models for representing complicated wells was also one of the project objectives.
**Results**: A simulation framework was finalized, wherein the "physical models" (black-oil, thermal and compositional) and the "discretization methods" (control-volume finite element, mixed finite element) were completely decoupled. The effectiveness of the decoupling described was demonstrated for a reservoir with complex well system. The original well model was developed for a black-oil simulator. A thermal physical model was coupled to this module. The end result was that thermal simulations could be performed on complex domains with complicated wells. Two distinct discretization methods, the control-volume finite element and the mixed finite element, with their own advantages were created to study complex domains with discrete fractures and faults and a verification hierarchy was created to ensure that the solutions from the models were accurate. One of the outcomes was that a single-phase analytical model for hydraulic fractures was used to validate the control-volume finite element simulation results. A methodology to grid complex, three-dimensional objects with faults and fractures was identified.

Benchmarking studies were performed where it was shown that the performance of simulators developed agreed well with results from other simulators such as Eclipse™. Intuitive well models of complicated wells for the mixed finite-element simulator were developed. A thermal simulation model formulation was completed and implemented for hot water flooding. The simulator structure was modified to use not only the conventional reservoir simulation boundary conditions (bottom hole pressure and rate constraints) but also constant flux boundary conditions and Dirichlet (constant pressure) specifications. The main goal of this project was to overcome difficulties associated with the representation and simulation of complex fractured/faulted systems with complicated wells. Significant advances were made in achieving this goal with the development of modular simulators that are able to access the most modern computational algorithms.

## *Wettability*

**Evaluation of Reservoir Wettability and its Effect on Oil Recovery**
**Contract**: DE-FC22-96ID13421
**Performer**: New Mexico Technological Institute
**Project Dates**: 7/1/96 - 1/31/2002
**Objectives**: (1) Improve understanding of the surface and interfacial properties of crude oils and their interactions with mineral surfaces; (2) apply the results to improve predictions of oil production using laboratory measurements; and (3) recommend ways to improved oil recovery by waterflooding.
**Results**: Published results included investigations into crude oil characterization with respect to their tendency to alter wetting and the use of crude to create mixed-wet conditions for studies of the influence of mixed-wetting on fluid on fluid displacement. Experimental observations of contact angles on mica surfaces treated with synthetic reservoir brines or sea water have led to development of a new standard suite of tests that can be used for comparing the wettability altering tendencies of one oil with another. Relationships between techniques of wettability assessment in porous media were studied.

**Characterization of Mixed Wettability at Different Scales and its Impact on Oil Recovery Efficiency**
**Contract**: DE-FC22-99BC15205
**Performer**: University of Texas at Austin
**Project Dates**: 8/4/99 - 8/31/2003
**Objectives**: Investigate the stability of wetting films on various mineral substrates and the effect of crude oil and brine composition on wettability alteration.
**Results**: A model for asphaltene precipitation was developed that agreed with experimental observations on asphaltene solubility. An equation was formulated which can be used to estimate the phase behavior and interfacial tension of mixtures of associating (polar) molecules. The equation was tested for mixtures of hydrocarbons, methanol and water.

**Wettability and Oil Recovery by Imbibition and Viscous Displacement from Fractured and Heterogeneous Carbonates**
**Contract**: DE-FC26-02NT15344
**Performer**: University of Wyoming
**Project Dates**: 7/18/2002 - 1/17/2006
**Objectives**: (1) Relate wettability alteration of carbonate surfaces to methods of wettability control of carbonate rocks by adsorption from selected crude oils; (2) measure oil recovery and characterize wettability by spontaneous imbibition measurements for strongly water-wet carbonate rocks and for the same rocks after systematic changes in wettability induced by adsorption from crude oil; and (3) investigate the sensitivity of oil recovery to displacement rate for carbonate rocks.
**Results**: Wettability alteration at carbonate surfaces was measured for more than sixteen crude oils. Correlations for imbibition into carbonate rocks for very strongly water-wet and crude oil-induced wettability variations were reported. Sensitivity of oil recovery to flow rate was demonstrated for heterogeneous outcrop limestone for very strongly water wet conditions and for mixed wettability states established by adsorption from crude oil. Rate sensitivity of waterflood residual oil originally observed for reservoir carbonate rocks was demonstrated. The completed parametric studies of oil recovery by spontaneous imbibition and viscous displacement have

many other applications in improved oil recovery and reservoir diagnostics. These results confirm and explain the unexpected but repeatedly observed sensitivity of oil recovery to injection rate reported by industry for reservoir carbonate cores.

**Fundamentals of Reservoir Surface Energy as Related to Surface Properties, Wettability, Capillary Action, and Oil Recovery from Fractured Reservoirs by Spontaneous Imbibition**
**Contract**: DE-FC26-03NT15408
**Performer**: University of Wyoming
**Project Dates**: 7/1,/2003 – 6/6/2008
**Objectives**: Improve oil recovery from fractured reservoirs through improved fundamental understanding of the process of spontaneous imbibition by which oil is displaced from the rock matrix into the fractures.
**Results**: Researchers obtained imbibition data including novel pressure measurements that enabled estimation of pressures acting during imbibition. The effective dynamic pressure acts at the imbibition front and the pressure at the outlet core face that resists production of oil were modeled for imbibition. Extensive new imbibition data sets that greatly extend the parametric range of available imbibition data were reported. Combinations of brine viscosified by addition of glycerol and oils of different viscosity were used to investigate the effect of viscosity ratio, boundary conditions, and sample shape on oil recovery over wide ranges of viscosity. Researchers determined definitive measurements of the effect of radial versus linear flow on oil recovery. Results have been matched numerically by a newly developed simulation model for imbibition that incorporates the physical mechanisms demonstrated by dynamic network modeling. Mathematical models were developed to provide analytic models of similarity solutions for spontaneous imbibition. The results of this project aimed at improved physical understanding of the imbibition process, improved interpretation of routinely measured data, and new approaches to increasing oil recovery from fractured low-permeability oil-wet reservoirs. Very large reservoirs of this type—from which only a small fraction of in place oil has been recovered—occur in Alaska, Wyoming, and other Lower 48 States.