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TECHNICAL CONSTRAINTS LIMITING APPLICATION OF ENHANCED OIL RECOVERY TECHNIQUES TO PETROLEUM PRODUCTION IN THE UNITED STATES

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by

BETC Staff

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Bartlesville Energy Technology Center
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ABSTRACT

In the interval since the publication in September 1980 of the technical constraints[1] that inhibit the application of enhanced oil recovery techniques in the United States, there has been a large number of successful field trials of EOR techniques. The Department of Energy has shared the costs of 28 field demonstrations of EOR with industry, and the results have been made available to the public through DOE documents, symposiums and the technical literature. This report reexamines the constraints listed in 1980, evaluates the state-of-the-art and outlines the areas where more research is needed. Comparison of the 1980 constraints with the present state-of-the-art indicates that most of the constraints have remained the same; however, the constraints have become more specific.

INTRODUCTION

In 1974, the Energy Research and Development Administration (a predecessor of the Department of Energy) started granting cost-sharing contracts for enhanced oil recovery projects with companies actively engaged in the production of oil and gas. Through June 1975, cost-sharing contracts had been made with private industry for seven enhanced oil recovery projects. The program continued to expand until the number of cost-shared demonstration enhanced oil recovery projects between private industry and the Department of Energy reached 28.

In 1980, a list of technical constraints that inhibited the application of enhanced oil recovery techniques in the United States was published[1] by the Department of Energy. Also, a summary of the results of several of the more mature cost-shared projects was included in the publication. The results of the DOE cost-shared projects have been made available to the public through DOE documents, symposiums and the technical literature. Also, the results of other EOR projects have been disclosed extensively. The result has been a wealth of information on enhanced oil recovery processes.

The examination of the technical constraints for enhanced oil recovery published[1] by the U.S. Department of Energy in 1980 and comparison with the present state-of-the-art indicate that most of the constraints have remained the same; however, the constraints have become more specific. For example, it is now known that the displacement mechanisms of surfactant systems are dominated by phase behavior. The phase changes that may occur when the surfactant system is exposed to reservoir crude oil and brine must be understood before the surfactant system is injected into a reservoir.

The recent appearance in the technical literature of review articles has helped immeasurably in the preparation of this report. The selected references were restricted for the most part to the review articles, and the reader desiring a comprehensive bibliography is referred to them. Also, the Department of Energy Progress Reviews, Annual Reports and Final Reports for the various cost-shared projects were used extensively but these were not included in the references.

CONSTRAINTS COMMON TO ENHANCED OIL RECOVERY PROCESSES

Several common constraints apply to all the enhanced oil recovery processes and even to waterflooding. The most important of these and perhaps the most important problem in oil recovery today is poor sweep efficiency. It can be divided into vertical and areal sweep efficiency, and its causes are many among which are reservoir heterogeneity, permeability barriers, unfavorable mobility ratios, viscous fingering, gravity override, fractures, etc. The available tools for improving sweep efficiency are water-alternating-gas injection (WAG), foams, and polymers.

The beneficial effects of the use of foams on steamfloods and polymers on waterfloods have proved the value of these remedies for improving sweep efficiency. Nevertheless, the improvement is small in terms of the additional oil recovered compared to the original oil in place. There is an immense opportunity for improvement which seems to be overlooked. Polymer flooding and the use of foams point in the proper direction but an order of magnitude increase in effect is needed. Such an occurrence would be considered a breakthrough of major importance.

A second constraint to trials of enhanced oil recovery lies in reservoir management. Reports on the field trials of enhanced recovery systems complain frequently about "drift" or "regional drift" in a reservoir or complain that reservoir pressures were too high to inject at the planned rate. These possibilities should be recognized early, and remedial measures should be taken to overcome or minimize the effects of pressure and pressure gradients in the reservoir.

Other technical constraints are the high degree of planning and the specialized knowledge required to ensure the success of an enhanced oil recovery project. The technology ranges from moderately difficult for polymer flooding to exceptionally complex for surfactant/polymer flooding. At the present state of knowledge, answers for many of the problems cannot be found by "rule of thumb" methods but must be found through careful laboratory studies.

Simulation and laboratory modeling of enhanced oil recovery processes are valuable tools but interactive tools. The normal progression is to combine laboratory work and mathematical simulation to make a prediction of production for a particular process in a particular reservoir for the purpose of an economic evaluation. The next step is to conduct a pilot test and then to calibrate the simulation model with the results from the pilot and to use the revised model to make another economic study. Simulation models are available from descriptions in the literature and are available commercially, but the need is at all times for more accuracy. Therefore simulation must be approached as an interactive endeavor with developing knowledge of the process and field results.

A comprehensive knowledge of the reservoir is a necessity. This includes the oil saturation and its variation from place to place in the reservoir, the presence of gas caps or bottom water, net pay, and reservoir continuity. There is no substitute for a careful geological and reservoir study.

All enhanced oil recovery projects require an adequate supply of water. Requirements for quality and rate of usage vary from process to process with dry fireflooding being low on the amount of water required and surfactant/polymer flooding being high on water usage. The water usage, quality and sources become a part of the necessary planning of an EOR project.

The principal general technical constraints for enhanced oil recovery may be summarized as follows:

1. The need for methods to increase sweep efficiency.
2. The early recognition of reservoir management problems and the correction of such problems before starting a field trial.
3. The high degree of planning and specialized knowledge for a successful field project.
4. The need for more accurate simulation methods.
5. The need for a comprehensive geological and reservoir study.
6. Water of adequate quality and quantity is a requirement.

MISCIBLE FLOODING (INCLUDING CO_2)

Miscible flooding grew out of the concept of using a solvent to remove crude oil from reservoir rock. The complexity of miscible flooding grew out of the attempts to improve the economics of the process by substituting less costly materials for a simple solvent. At first, propane or liquefied petroleum gases were used as the solvent but research and pilot testing showed that normally gaseous material at high pressure or in an appropriate composition at lesser pressures could act as a solvent for the oil. Under miscible conditions, interfaces and capillary forces between the oil and the gas are eliminated. Natural gas at high pressure and natural gas with added intermediate-molecular-weight hydrocarbons were researched and field tested, and the results indicated the desirability of alternates to the hydrocarbon gases because of the costs (in the United States) relative to the amount of oil recovered. Attention was turned to the use of nitrogen, flue gases and carbon dioxide (CO_2) as substitutes for all or part of the hydrocarbon gases used in the miscible displacement process. The ranges of compositions, phase relations, pressures and temperatures at which the various mixtures are effective have been outlined extensively in the literature.

After 30 or more years of research and field trials, miscible flooding as an enhanced oil recovery technique has come "of age" and it is now at the beginning of the mature stage. The principal mechanisms involved in miscible flooding are well documented in the literature. Pilot testing has shown that CO_2 is effective for displacing oil in sand reservoirs at temperatures and pressures as low as 73°F and miscibility pressures about 1,000 psi and as high as 225°F and 5,100 psi. A pilot test in a carbonate reservoir indicated that CO_2 would displace oil at 245°F and 3,180 psia.

An excellent review article by Stalkup[2] divides miscible flooding into three types: the first-contact miscible process; the vaporizing-gas drive process; and the condensing-gas drive or enriched-gas drive. In the first-contact miscible process, the recovery agent as injected is a solvent for the reservoir oil. It is miscible with the oil in all proportions, and the mixtures always are single phase. The vaporizing-gas drive process achieves miscibility under appropriate pressures and compositions by vaporization of the intermediate components of the reservoir oil into the gas. The condensing-gas drive achieves miscibility by solution of the heavier components from the injected gas into the reservoir oil. Stalkup, after reviewing more than 50 field tests of the first-contact, 19 condensing-gas and 11 vaporizing-gas projects, concludes from the available data that no one process performed appreciably better or worse than another for a given slug size.

Economics has influenced the recent evolution of the miscible processes in that CO_2 as the recovery agent appears to be the least expensive of the miscible flooding agents, especially in those areas where CO_2 is available in large quantities. CO_2 also has the advantage in that it has a much lower miscibility pressure with certain reservoir oils. Holm[3] indicates that the time has come for wide spread application of CO_2 for enhanced oil recovery, summarizes factors to be considered in selection of reservoirs and concludes that a ratio of CO_2 to oil of 8 Mcf/bbl will be required for profitable operation (1982) but in many reservoirs ultimately 3 Mcf of CO_2 will remain in the reservoir for each barrel of oil recovered.

The use of nitrogen and flue gases has been reviewed and compared with CO_2 for use in enhanced recovery by Anada[4] for the Department of Energy. Anada concluded that nitrogen may have a cost advantage over flue gas and CO_2 but it has the disadvantage of very high miscibility pressures. Flue gases are generally corrosive in the presence of water and may require the removal of sulfur compounds before use. However, at the time (1980) the lack of field results prevented Anada from making an economic comparison between the use of nitrogen, flue gases and CO_2 for enhanced oil recovery.

Conclusions from DOE Cost-Shared Field Tests of CO_2

Cost-shared EOR field projects between industry and the Department of Energy are listed in Table 1. Some of the conclusions applicable to or derived from these projects are as follows.

1. CO_2 can be used for tertiary recovery and will displace oil and will form a high oil-cut bank in a watered-out sandstone reservoir.
2. Confinement of CO_2 to the immediate area of a pilot trial in a large oil reservoir is virtually impossible with present day technology. This is a result of the unfavorable mobility ratio and the heterogeneity of the reservoirs.
3. Pilot tests can demonstrate technical feasibility of the process but are unlikely to demonstrate the economics of the process.
4. A non-producing minitest indicated that the CO_2-WAG process could reduce oil saturation to 5 percent in a dolomitized carbonate reservoir at 3,180 psia and 240°-245°F. Areal sweep was considered good but vertical sweep was poor.
5. A mixture of 5 percent natural gas and 95 percent CO_2 reduced oil saturation to less than 1 percent in a sand reservoir at 225°F and 5,100 psi. Cumulative oil production as of December 31, 1982, was 88,400 bbl which exceeded the projected water drive recovery by 23,400 bbl. Production continued at rate of 245

BOPD.

Constraints for Miscible Flooding

The list of constraints for miscible flooding have remained about constant since publication of the first DOE document[1] in May 1980, but now it is possible to be more specific in defining the constraints. As examples, immediate breakthrough of the solvent and drive gas can be expected with present day methods for mobility control; therefore recovery methods and equipment for recycling the solvent should be planned and installed at the start of a commercial project. Also, experience has shown that a determination of miscibility pressure alone is not sufficient. Improved understanding of phase behavior and displacement mechanisms is needed to tailor the recovery system properly to the reservoir oil and reservoir conditions.

Presently, CO_2, CO_2 with added components, and CO_2 vaporizing-gas drive appear to be the most favored of the miscible processes for economic enhanced recovery of oil on a commercial scale. The listed constraints that follow are weighted heavily toward the CO_2 and related processes for commercial application.

1. An early and premature breakthrough of the CO_2 recovery system for horizontal floods

can be expected. It is believed to be caused by reservoir heterogeneity, adverse mobility, gravity override and viscous fingering.

2. In the absence of an order of magnitude improvement in methods for controlling premature breakthrough, it is necessary to plan and install equipment to recover the miscible solvent system at the start of a commercial project.
3. Methods for the accurate prediction of miscibility pressure, displacement efficiencies for various system compositions, single contact phase properties, and dynamic phase behavior are primitive at best or unknown. Consequently, extensive laboratory work is needed for design of any of the miscible processes. Probably at best, laboratory results will be necessary to fine-tune the processes.
4. No methods or guidelines are available for selection of the best miscible process for a specific reservoir oil at given reservoir conditions or for optimizing slug sizes and compositions for the selected process. Again, fine-tuning probably will require laboratory work.
5. CO_2 is probably most efficient with reservoir oils of low or moderate viscosity.
6. Miscible CO_2 flooding requires a reservoir deep enough to withstand the miscibility pressure.

Needed Research for Miscible Flooding

- Since miscible flooding usually involves an unfavorable mobility ratio, the improvement of sweep efficiency becomes exceptionally important.
- If CO_2 overrides the oil zone and breaks through to several producing wells, a technology capable of stopping the by-passing of the oil zone is needed.
- Experimental work is needed to increase understanding of the recovery mechanisms and the effects of phase behavior on the recovery mechanisms.
- Knowledge is needed regarding the effects of impurities and additives on the phase behavior of miscible systems.
- Guidelines are needed for selection of the best miscible process for a specific reservoir oil at given reservoir conditions and for optimizing slug sizes and compositions for the selected process.

POLYMER FLOODING

Polymer flooding generally has been received as a means for improving waterflood recovery with the result that it has not emerged as a full-fledged technique for enhanced oil recovery. However, the wide use of polymers in surfactant flooding and occasionally in CO_2 miscible flooding emphasizes the need for mobility control and overcoming the effects of reservoir heterogeneity in enhanced recovery methods. Therefore an understanding of the objectives, the failures and the successes of polymer flooding is an advantage in the planning of future enhanced recovery projects.

Presently, two types of polymers have been available commercially for mixing with injection water: synthetic polymers (such as polyacrylamides) and biologically produced polymers (such as polysaccharides). The polymers improve the mobility ratio of the waterflood by a marked increase in viscosity over that of water alone. Although the increase in viscosity is important, the capacity of the polymers to decrease the permeability of reservoir rocks to water is of extreme importance to enhanced recovery operations. Field trials[5,6,7] in the North Burbank and North Stanley fields in Oklahoma have shown that the change in permeability caused by partially hydrolyzed polyacrylamides lasts for several years. It must be realized that the capacity of the polyacrylamides to decrease the permeability of reservoir rocks to water and for the decrease to last for several years after the injection of the polymer has been stopped is due to the adsorption or entrapment of the polymer on or in the reservoir rock. Consequently, adsorption or entrapment is not necessarily a harmful effect.

Although the use of polymers to improve waterflooding has provided at best only a modest improvement in waterflood recovery, their use has given a clue towards the solution of perhaps the most important need in enhanced oil recovery: a major breakthrough in improvement of sweep efficiency. Efforts in this direction have led to a few trials of polymeric gels. Further research and field trials of advanced mobility control systems will be needed to realize the required necessary improvement.

Although the influence of fluid mobilities on waterflood recovery was known in 1949, no marked improvement was made until Pye[8] and Sandiford[9] discovered that the mobility of water in porous media could be reduced markedly by small amounts of a water soluble polyacrylamide. In 1978, Chang[10] reviewed polymer flooding and published an excellent bibliography. He listed in detail the pertinent facts about 16 field tests. Since then, polymer flood projects (polymer only) have been announced for at least three field trials[11,12].

Conclusions from DOE Cost-Shared Field Tests of Polymer Flooding

Cost-shared projects between industry and the Department of Energy are listed in Table 2. The conclusions resulting from these field trials of polymer flooding follow.

1. The ultimate incremental oil recovery from a waterflooded sand reservoir as a result of a polymer flood with polyacrylamide was estimated to be 570,000 bbl or about 1.4 percent of the original oil-in-place. Under mid-1982 economic conditions the project was judged to be economically attractive.
2. The field trials of the biopolymers in polymer flooding indicated that maintaining injectivity can present serious problems when the bacterial debris has not been removed from the injection fluid. The use of a biocide was necessary.
3. A scant technical success was the most that could be achieved by one of the biopolymer field trials.

Constraints for Polymer Flooding

Since polymer flooding (without surfactants) has been one of the enhanced recovery techniques shown to be economically feasible and since polymer flooding is used as a part of other recovery processes, a full understanding of the limitations of polymers and their usage is vitally important. Unfortunately, polymers are only moderately effective in mobility control and improvement of sweep efficiency. Therefore more research and field testing on agents to improve mobility control and sweep efficiency are necessary for enhanced recovery of oil to become economically feasible in a wide range of reservoirs.

Constraints for polymer flooding follow.

1. The polymer solutions must be thoroughly compatible with the crude oil, resident reservoir brine and reservoir rock. If not, preflush conditioning of the reservoir is necessary.
2. Polymers, especially the polyacrylamides, are subject to shear degradation. Care should be taken in selecting pumps, valves, orifices and perforations to keep shearing to a minimum.
3. Polymers degrade at temperatures about 200°-225°F in the absence of oxygen.
4. Trace amounts of oxygen degrade polymers. Consequently, oxygen scavengers and inert gas blankets are necessary to protect the polymer.
5. The use of biocides is recommended for polyacrylamides and is a necessity for biopolymers.
6. The polyacrylamides are sensitive to salinity. Their efficient use depends upon a source of fresh water.
7. There is probably an optimum molecular weight range for the polyacrylamides that depends upon the pore size distribution of the reservoir rock. A low-molecular weight polymer would not be effective in a reservoir where flow is dominated by hair-line fractures.

8. Polymers decrease the mobility of water; therefore, there must be enough injection capacity to permit a constant injection rate during the injection of the polymer solution else there will be a decrease in the production rate for waterflooding.

Needed Research for Polymer Flooding

- Methods to determine the appropriate polymer molecule for a specific reservoir rock are needed to improve polymer flooding.
- Polymeric gels and cross-linked polymers have been used occasionally to improve sweep efficiency. Their usage needs to be explored more fully by field testing to see if they are an improvement over polymers alone.
- Polymers that are more resistant to high temperatures, high salinity, shear degradation and microbial degradation are needed.
- More efficient biocides are needed for use with polyacrylamides and expecially with polysaccrides.

SURFACTANT FLOODING

Surfactant flooding is the outgrowth of the concept that oil could be washed or laundered out of the reservoir rock. On a more scientific basis, it involves the reduction of the interfacial tension between the oil and the recovery system to an extremely low level so that the capillary forces between the oil and the recovery system nearly disappear. If the capillary forces were reduced to zero the oil would be miscible with the recovery system. In effect, the surfactant system displaces the oil under nearly miscible conditions.

In actual field practice, the surfactant systems have ranged from a large pore volume fraction of a low-concentration surfactant dispersion in water to a small pore volume fraction of a more concentrated surfactant system of several components. Surfactant systems consist of a surface active agent usually a mixture of petroleum or synthetic sulfonates of a specified range of equivalent weights, a co-surfactant which may be a moderate molecular weight alcohol, salts at specific concentrations, water and, in certain preparations, crude oil and a refined oil. Other chemicals may be added to the system. Most surfactant systems carry trademarks and have been patented, and the exact compositions may be considered proprietary. Surfactant flooding has been called micellar or microemulsion flooding and is usually followed by a polymer flood; hence, the terms micellar/polymer or microemulsion/polymer flooding. The behavior of surfactant systems in the presence of the reservoir oil, the resident reservoir water and the reservoir rock is indeed complex. Phase changes can occur that may result in a rejection of a very viscous fraction from the oil, a microemulsion with several times the viscosity of either the surfactant system or the oil or outright precipitation of one or more of the components as a metallic salt. A vast amount of experience is necessary to anticipate the behavior of a surfactant system under reservoir conditions, and even then unwelcome surprises can occur. Often these show up as unexplained decreases in well injectivity.

Surfactant systems have been the subject of numerous publications and patents. Gogarty[13] reviewed the state-of-the-art in 1978 and presented a large bibliography. Also, the Department of Energy has supported research on surfactants and surfactant systems at several universities and in seven large field trials. These have resulted in numerous technical papers. In addition, surfactant flooding has been the subject of a great number of papers at the three SPE/DOE Joint Symposiums on Enhanced Oil Recovery in 1980, 1981 and 1982.

Most recently, the field trials seem to favor the high-concentration surfactant systems. Since these systems consist of relatively expensive chemicals, the principal problem has been to maintain the integrity of the surfactant slug from the injection well to the producing well. Possible threats involve degradation of the slug by adsorption, dilution or chemical reaction with reservoir oil or the resident reservoir water, dispersion, partitioning of the chemicals between phases, reservoir heterogeneity and other factors perhaps not recognized at this time. These are complex and difficult problems and the difficulties should not be underestimated in the planning of a surfactant flood.

In addition to the difficulty of maintaining the integrity of the surfactant slug, there is the added constraint of the interfacial tension between the oil and the displacing fluid. (The relationship can be expressed as the critical capillary number below which the residual oil will not be displaced by the flowing fluid. Since the critical capillary number for displacement of residual oil in most reservoirs is several orders of magnitude larger than that achieved in a typical waterflood, the only practical means for displacing the waterflood residual oil is to reduce the interfacial tension by several orders of magnitude[5]). Displacement tests[5] in Berea cores showed that recovery of residual hexadecane was essentially complete at an interfacial tension between the displacing surfactant dispersion and the hexadecane of 0.025 mN/m (dynes/cm). Fanchi and Dauben[14] state that mobilization of residual oil is best achieved at interfacial tension values below 10^{-3} mN/m for most reservoir rocks. The phase properties that result in such low interfacial tensions have been described in the literature[14-18]. Reed[18] emphasizes that the mechanisms of surfactant flooding are dominated by the phase behavior of the surfactant/oil/brine system. He also states that the first major breakthrough was recognition that conditions of temperature, salinity, oil type, surfactant and co-surfactant type etc., giving rise to a middle-phase microemulsion, are near optimal for oil recovery. Thus for surfactant flooding to be successful in a commercial sense, a detailed knowledge is needed of the interfacial tension and phase behavior that occurs when the system is exposed to the reservoir rock, the reservoir oil, and the resident water in the reservoir. Present knowledge renders short cuts and rules of thumb dangerous to successful surfactant flooding. An example of the careful evaluation and laboratory work necessary for achieving a technical success in surfactant flooding is given by Fanchi, Duane and Hill[19] and Fanchi and Dauben[14]. Until the mechanisms and theoretical phase behavior have been developed and thoroughly understood, the matching of a surfactant system to a given reservoir oil, resident reservoir water and reservoir conditions must be done in the laboratory. Probably, the fine-tuning of the system will require laboratory work.

Conclusions from DOE Cost-Shared Field Tests of Surfactant Flooding

Cost-shared surfactant floods between industry and the Department of Energy are listed in Table 3. It appears that the state-of-the-art varies from surfactant system to surfactant system as is evident from the variable amount of ad hoc research needed to carry out the projects. Results have ranged from a minor displacement of additional oil to recovery of substantial quantities of additional oil.

By June 1983, the economics of only one of the DOE cost shared projects had been explored for commercial expansion. Trantham[20] concluded that economics for commercial-scale expansion of the particular surfactant system used in the North Burbank Unit reservoir were marginal at an after-tax discounted-cash-flow rate of return of about 15 percent. Regarding the Robinson Field project, 1,002,588 bbl of additional oil have been produced through August 1983 from a 407-acre tract and additional recovery is expected in future years. It is believed the economics for the Robinson Field project will be considered at least marginal.

The conclusions resulting from the DOE cost shared field trials of surfactant flooding follow.

1. Surfactant flooding under favorable circumstances can produce significant quantities of additional oil. However, "favorable circumstances" cannot be defined precisely at this time. Nevertheless, all but one of the systems used in the trials displaced additional oil.
2. More accurate means are needed for determining the size and nature of the preflushes required to protect the surfactant system from reservoir brines and ion exchange with clay

minerals.

3. Maintenance of well injectivity and well productivity remains a difficult problem as not all the causes of well damage have been identified. The ordinary scaling problems apparently do not account for all the well damage problems.
4. Efficient biocides are needed to control bacterial growth if biopolymers are used in the surfactant system.
5. Corrosion does not appear to be a problem.

Constraints for Surfactant Flooding

Since polymers are widely used in controlling mobility in surfactant flooding the constraints listed under polymer flooding are also applicable to surfactant flooding in which polymers are used. In addition to the constraints involved in the application of polymers to improve sweep efficiency, the surfactant system by itself is perhaps the most complicated of the enhanced recovery techniques and as a result, it has constraints that are narrow and restrictive. The constraints for surfactant flooding follow.

1. Present knowledge indicates that adsorption, dispersion, chemical reactions with various ions in resident water and minerals in the reservoir rock itself, and uncontrolled or

unanticipated phase changes are the most destructive factors influencing surfactant flooding. Therefore, extensive laboratory work is required before application to control phase properties and destructive influences so that the integrity of the surfactant slug and sufficiently low interfacial tensions are maintained between injection and producing wells.

2. Better guidelines are needed for the design of preflushes to protect the surfactant system from the resident water in the reservoir rock and to remove divalent ions from reservoir clays.
3. Surfactant systems more tolerant of the ions found in reservoir fluids are needed.
4. Many surfactant floods have been plagued with well injectivity and productivity problems. The causes need to be identified and remedial measures devised.
5. If polymers are used in the surfactant system or in afterflushes, the constraints for polymer flooding also apply.

Needed Research for Surfactant Flooding

- Design criteria should be determined for the preflushes needed to condition reservoirs for surfactant systems.

- Methods for controlling ion exchange between surfactant systems and the clays in the reservoirs should be explored.
- Surfactant systems need to be made more tolerant to the divalent ions found in reservoir fluids.
- Surfactant systems for use in high temperature and high salinity reservoirs should be devised.

ALKALINE OR CAUSTIC FLOODING

Even though alkaline or caustic flooding has been known since the 1920's, it is in several ways the least understood of the major processes for enhanced recovery of oil. Successful and technically successful field trials of alkaline flooding have been reported in the literature but no opinions have been offered as to why alkaline flooding appears to be effective for enhanced oil recovery in one reservoir but not in another. In addition to being the primary agent for an enhanced recovery process, alkaline flooding has been proposed and used in the preflush for micellar/polymer projects. Mayer, Berg, Carmichael and Weinbrandt[21] recently reviewed alkaline flooding and concluded that present tests and research should establish conclusively the profitability of alkaline flooding.

Previously, Johnson[22] reviewed alkaline flooding and listed four mechanisms by which alkaline flooding recovers additional oil. Mayer et al[21] listed a fifth mechanism which was traced to previous investigators. These were:

1. Emulsification and entrainment
2. Wettability reversal (oil-wet to water wet)
3. Wettability reversal (water-wet to oil wet)
4. Emulsification and entrapment
5. Reaction with divalent ions and precipitation of solids to plug high-permeability channels.

A possible sixth mechanism has been suggested[22] in the literature and that is the reaction of the alkaline agent with components in the crude oil to form surface active agents which lower the interfacial tension between the displacing agent and the crude oil. Although much research has been conducted on alkaline flooding, there still remains an apparent ambiguity in the literature as to the mechanism or mechanisms by which alkaline flooding is supposed to recover additional oil from a reservoir. It appears that much more research should be done to establish the mechanism or mechanisms if such exist by which additional oil can be recovered by alkaline flooding.

Mayer et al[21] listed 12 completed field tests of alkaline flooding from which some judgement could be made regarding economics, 5 completed but undocumented tests and the certification of 41 alkaline projects under the DOE Tertiary Incentive program. The completed tests with documentation indicate that incremental oil was recovered at costs from \$0.36 to \$6.35 per barrel of oil based on a cost of $0.15 per lbm for sodium hydroxide for the more successful projects. The costs for the other documented projects were much higher. The alkaline agents considered in alkaline flooding have been sodium hydroxide, sodium orthosilicate, sodium metasilicate, sodium carbonate and ammonia. Polymers and various salts have been considered or used in connection with alkaline flooding.

Conclusions from DOE Cost-Shared Field Tests of Alkaline Flooding

The two field trials of alkaline flooding cost-shared between industry and the Department of Energy are listed in Table 4. Both tests were in California reservoirs where alkaline flooding was believed to be most applicable but results have been disappointing. The final report for one project states there has been no significant response to the alkaline injection, but there has been an indication of decreases in the water to oil ratio in the central producing well in the inverted 5-spot pattern area. The other project showed an early increase in production of about 200 BOPD which was believed to be the result of remedial work on wells. Net production has decreased about 40 percent since then. However, the water-to-oil ratio has not increased as much as would be expected under waterflooding. This project, also, is considered disappointing.

No firm conclusions are justified by the results of these two tests but it can be speculated that the consumption of the alkali in the reservoir was much greater than anticipated by the laboratory work. As a result, neither test constitutes a realistic trial of alkaline flooding, but this is sheer speculation.

Constraints for Alkaline Flooding

Since alkaline flooding has been reported as successful in some reservoirs and a failure in other seemingly similar reservoirs and reservoir oils, questions arise as to whether the mechanisms by which alkaline flooding enhances oil recovery are known with any degree of certainty. If it is conceded that the mechanisms have been identified, then it must be asked whether the consumption of alkali has been determined accurately in all cases. If the mechanism is a reaction with components in the crude oil to form surfactants which lower the interfacial tension, between the displacing fluid and the crude oil, the questions become--is the interfacial tension low enough to improve displacement and can the zone of low interfacial tension be propagated across a reservoir. In view of these questions the technical constraints for alkaline flooding become:

1. Identification of the mechanisms by which alkaline flooding enhances oil recovery and determination of reservoir and crude oil properties that are conducive

to alkaline flooding is uncertain.

2. The consumption of the alkali agent by the specific reservoir and crude oil and the estimation of the amount of agent necessary to move the front from an injection well to a producing well must be determined.

Needed Research for Alkaline Flooding

- It appears that research on alkaline flooding is still in the beginning stage. Some field tests appear to succeed whereas others fail without any apparent reason. At least six mechanisms have been suggested by which alkaline flooding recovers additional oil; yet they range from emulsification, to reduced interfacial tension, to mobility control with precipitates. For alkaline flooding to become established the mechanisms by which additional oil is recovered must be known.

THERMAL RECOVERY

Thermal recovery processes are the most advanced of the enhanced recovery techniques. They already have made an impact on oil production in the United States, Venezuela and Canada. Prats[23] reports that thermal recovery methods resulted in 388,000 BOPD of additional oil recovery in 1981 in the United States. Of that amount only about 20,000 BOPD was from combustion processes. Matthews[24] reports the current production from steam to be about 550,000 BOPD world-wide and estimates in 1990 the overall world production from steam processes will be about 850,000 BOPD.

The principal mechanism by which thermal methods enhance the recovery of crude oil is the reduction of the resistance to flow in the reservoir through a reduction in the viscosity of the crude oil. The heat to decrease the viscosity can be generated in place or introduced into the reservoir by the injection of hot fluids. In practice, the methods fall into two principal types--in-situ combustion and steam injection. Also, heat has been introduced into reservoirs by injection of hot water and hot gases which are usually the products of combustion conducted on the surface. Thus, thermal recovery involves the complexities of heat transfer, flow of fluids in porous media and for in-situ combustion the kinetics of combustion.

These diverse aspects of thermal recovery have been collected and unified into an excellent reference volume by Prats[23]. The evolution and current status of steamflooding have been summarized very ably by Matthews[24]. In commercial practice today, steamflooding is more widely accepted than in-situ combustion whereas the injection of hot water and hot combustion gases have not been practiced to any great extent. However, Prats[23] lists conditions that might make combustion more attractive than steam. These are (1) high injection pressures that make steam generation difficult, (2) deep reservoirs that make heat losses with steam excessive in injection wells, (3) a lack of fresh water or excessive water treatment costs that make steam generation too expensive, (4) clay swelling problems caused by fresh water in the reservoir, and (5) thin or low permeability reservoirs where wet combustion is more efficient.

Traditionally, thermal methods have been thought to be most applicable to viscous or heavy oil reservoirs but the lower viscosity limitation has almost disappeared from screening criteria. Prats[23] states that where condensed steam does not cause formation damage or where there is not enough fuel for combustion there are few known technical reasons for not considering thermal recovery methods for light crude oils. In this regard, Chu[25] lists 40° API as the upper gravity limit for crude oils in fireflooding.

Fireflooding

In-situ combustion or fireflooding was the first of the thermal recovery methods to receive considerable attention and may be considered as an advanced technology. It has developed into two types depending upon the use of water to assist in transferring heat from the combustion zone to the displacement zone. Thus the process is divided into dry and wet combustion. A third type called reverse combustion has been mentioned in the literature but it has not been established as a separate process. In this case combustion is initiated at the producing well and the combustion front moves counter to the flow of air towards the injection well. Most investigators now believe that it is only a matter of time until the reverse combustion process converts itself into the forward combustion type. It must be noted that when the conversion occurs the burn front is likely to be very near the producing well.

Chu[25] in January 1982 listed 25 selected successful and 9 aborted firefloods but, historically, there have been many more trials of fireflooding. Thus the strengths and weaknesses of in-situ combustion have been well established. In general, it has been accepted that the air requirements for wet combustion are less than those for dry combustion and that wet combustion gives a quicker production response. In addition, wet combustion results in less severe corrosion of the production equipment than dry combustion. However, in low permeability reservoirs the introduction of water into the injected air may reduce injectivity to unacceptable levels. Also, reaction between the water and swelling clays can reduce injectivity to unacceptable levels.

Conclusions from DOE Cost-Shared Field Tests of Fireflooding

The most successful of the firefloods with costs shared by DOE (listed in Table 5) was the Bodcau project in the Bellevue field, Louisiana, operated by Cities Service Company. This project was judged to be both technically and economically successful by Trantham[26]. The project paid out quickly and produced an attractive rate of return on the investment. The economic success came with the production of 926,000 barrels of additional oil (June 1982) even though operating difficulties were severe and well workovers reached 3.7 per month. The project was well planned and remedial work was performed in a timely manner.

Of the three remaining projects with costs shared by DOE, two were terminated before combustion was started and the third was terminated after difficult operating conditions and high operating costs were evident. The Little Tom project was abandoned after conventional and thermal stimulation methods did not result in profitable producing rates from the wells. Injection pressures were higher than anticipated, and it is doubtful that combustion was ever started during efforts to stimulate the wells thermally. The Lynch Canyon project was terminated after the drilling and coring of four wells provided new and discouraging information on the reservoir. The volume of oil sand was lower than previous estimates, drilling costs were high due to overlying high-pressure water sands, investment costs were higher than expected due to environmental considerations and the reservoir oil was more viscous than anticipated. The Paris Valley project was abandoned after combustion was started when extreme operating difficulties were apparent and costs were excessive.

In spite of the limited experience gained from the DOE cost-shared projects, the resulting conclusion is that proper planning, adequate provision for anticipated difficulties and careful operations can produce a successful fireflood.

Constraints for Fireflooding

1. Gravity override to the upper portion of the reservoir seriously decreases the vertical sweep of the fireflood.

2. Although in-situ combustion has the advantage of supplying its own fuel, for the lighter oils there must be sufficient fuel left behind the displacement front to support combustion and generate enough heat to support the process.

3. Breakthrough of the fire front into producing wells can cause severe damage to casing, cement, tubing and pumps.

4. Well remedial work, as experience has shown, is a continuous and expensive problem. Techniques are needed to avoid well damage.

5. Procedures are needed for keeping wells producing oil after hot fluids appear in the well. Rod fall in heavy viscous oil is a problem before the hot fluids reach the producing well.

6. Lifting viscous oil when water and large volumes of combustion gases are present presents serious difficulties.

7. Without adequate precautions, explosions in the compressed air system can become a dangerous hazard.

8. Sanding, corrosion and heat damage in producing wells and treatment resistant emulsions can become difficult problems to overcome.

<u>Needed Research for Fireflooding</u>

- Research effort is needed to improve the laboratory measurement of parameters that affect the combustion process.
- Serious consideration should be given to methods for overcoming the gravity override difficulties that affect the vertical conformance of the fireflood.
- The simulation methods need to be improved by including gravitational effects, so that project design can be optimized with respect to reservoir and lease boundaries, lease configuration and the presence of underlying aquifers.

Steamflooding

Steamflooding, including cyclic steam stimulation has become the principal enhanced oil recovery process based on the amount of oil produced by each process. Steamflooding started in 1959-60, and the cyclic steam stimulation or steam soak process was discovered by accident in attempting to relieve the reservoir pressure after steam injection. The steam soak process spread quickly through the heavy oil fields of California and became the dominant thermal method until the 1970's when the number of steam drive projects began to grow. Although the steam soak process produced large quantities of oil and contributed much information on the use of steam, its future use will be as a method for stimulating wells, and it will be used for the most part to prepare wells for steam or fireflooding.

The use of steam for enhanced oil recovery has become a mature technology. The literature is replete with theories, descriptions and results of projects. Matthews[24] gives a thorough review, discusses the bases for selecting and designing economic steamfloods and discusses the constraints. Prats[23] presents a comprehensive review of the state-of-the-art, methods for predicting recovery, and production practices.

The conditions most favorable to steamflooding are high oil saturation, thick oil zone, oil of moderately high viscosity, high permeability, porosity more than 20 percent, good continuity between wells, low reservoir pressure and shallow depths. Conditions most unfavorable are deep high-pressure reservoirs, low oil saturation, swelling clays in the reservoir rock and lack of water suitable for steam generation. Heat loss in the injection wellbore can be a serious problem in the deeper reservoirs and in cases where the injection rates are low. If the injection rates are low the ratio of heat lost in the wellbore to the heat delivered to the sand face becomes high. Also, in thin reservoirs the ratio of heat lost to the over- and underburden to the heat remaining in the reservoir can become high. Thus, heat losses in the wellbore and to the over- and underburden reduce the efficiency of the steamflood process. However, methods for predicting such heat losses are well established, and the efficiency of heating the reservoir can be estimated during the design stage.

During the development of steamflooding it became apparent that the effective transmissivity of the reservoir to the desired fluid was important but evasive because it varies even between the injection and the producing well. Transmissivity is defined as the ratio of the product of the permeability to the fluid times the thickness of the formation divided by the viscosity of the fluid. The permeability to the fluid varies with the saturation of the fluid, and the viscosity of the fluid varies with temperature. Thus, it is difficult to set an upper limit on viscosity of the oil beyond which steamflooding (or for that matter fireflooding) should not be considered. Reservoirs with extremely high viscosity oil present a more difficult challenge.

Conclusions from DOE Cost-Shared Field Tests of Steamflooding

Costs were shared between industry and DOE on two steamflood projects (see Table 5). A third project in the Paris Valley Field, was originally scheduled as a wet combustion project but, in hindsight, it can be considered as a cyclic steam stimulation project in a reservoir with extremely high viscosity oil. Although complete analyses have not been made for the steamfloods, both projects recovered substantial quantities of additional oil. The cyclic steam stimulation later changed to a steamflood in the Cat Canyon Field recovered oil at rates as high as 418 BOPD for October 1981 from nine producing and four injection wells in a reservoir containing 9° API crude oil at a viscosity of 25,000 cp. However, the results were considered marginal. The steamflood in the "200" Sand of the Midway-Sunset Field had recovered 395,841 barrels of additional oil by December 31, 1982 from a reservoir that had unfavorable response to cyclic steam injection. As of December 31, 1982, steam injection continued in 14 injectors with steam generators operating at full capacity, and oil production was in excess of 10,000 barrels per month. Cumulative steam injection was 4,910,775 barrels for a cumulative ratio to oil of 12.4 bbl per bbl as of December 31, 1982.

The project in the Paris Valley Field is of interest because it was originally planned as a trial of wet combustion. The reservoir contains extremely viscous crude oil ranging in viscosity from 23,000 cp in the Lower Lobe of the Ansberry sand to 227,000 cp in the Upper Lobe. The reservoir also contains bottom water. After producing 108,599 bbl of oil by cyclic steam stimulation the operation was converted to fireflooding. After production of 2,721 bbl of oil by fireflooding, the project was terminated because fireflooding was not considered feasible for the reservoir. Operating expenses were considered very high for both processes.

Although conclusions are limited, steamflooding can be technically successful where cyclic steam stimulation results have not been favorable. With present knowledge, neither steamflooding nor fireflooding should be used in reservoirs with extremely viscous oil or where there is bottom water.

Constraints for Steamflooding

Although the principal constraints for steamflooding have been mentioned previously, they are tabulated here for emphasis. The constraints are:

1. Heat losses in the wellbore restrict the depths to which steam can be applied. Also, heat losses to the over- and underburden set the minimum thickness to which steam can be applied economically.
2. Clays that swell in the presence of fresh water will eliminate a reservoir from consideration for steamflooding if the clays are present in sufficient quantity to cause injection trouble.
3. In flat low-relief reservoirs, steam and hot water will override the oil and flow through a thin zone at the top of the formation to the producer. This can also be true for reservoirs with extremely high permeability. Thus, injection rates must be kept low to control the steam breakthrough with the result that vertical sweep efficiency of the reservoir is improved somewhat but still remains low. There is some minimum steam injection rate for a given reservoir to achieve efficient oil production.
4. Operating problems in reservoirs with extremely high viscosity oil can make steamflooding uneconomical.
5. Successful steamflooding must have an adequate

water supply.

Needed Research for Steamflooding

Although the technology for steamflooding has been labeled as mature, this means that the important problems have been identified and workable solutions have been devised. The industry must now turn its attention to improving the process. For example, if a solution to the general sweep efficiency problem, as mentioned previously, can be devised, perhaps the solution can be applied to the steam override problem.

- Methods for improving sweep efficiency are needed for steamflooding. It is believed the improvement should be at least an order of magnitude greater than that offered by polymers, foams, etc.
- Improved methods for insulating steam injection strings to reduce heat loss would be helpful, but the insulation must be strong enough to withstand normal oil field handling and still be cost effective.

Steamflooding with Ancillary Materials

The use of foams to reduce the mobility of gases in porous media has been known for 20 to 25 years. The results of considerable laboratory work have been reported in the technical literature. The addition of foaming agents to steam in an effort improve cyclic steam stimulation and steamflooding has been practiced for about 10 years but at a low level of activity. Except for the projects with costs shared by DOE the results of the use of foaming agents with steam have not appeared to any great extent in the technical literature.

Conclusions from DOE Cost-Shared Field Tests of Steamflooding with Ancillary Materials

The tests of steamflooding with ancillary materials with costs shared by DOE are listed in Table 5. These have involved foaming agents with noncondensable gases in a total of five tests in the Midway-Sunset, Cat Canyon, and San Ardo fields. Foaming agents with gels were tested in the Kern Front field. The surfactant, Suntech IV, and nitrogen were used in the Kern River field.

Laboratory work done in preparation for the field testing of foaming agents by the CLD Group, Inc. showed that the foaming agents had to be coinjected with noncondensing gas which was mixed with the steam or injected in alternating slugs with the steam. However, noncondensing gas was not used in the Kern Front field tests. All of the tests showed that steam with foaming agents changed the injection profiles in injection wells which indicated that steam was diverted from its original channels. Substantial increases in oil production were observed at several of the tests, and favorable results were observed at all of the tests as outlined in Table 6.

The results presented in Table 6 show that foaming agents can increase the oil recovered by steamflooding. The operator reported the trial in the Kern Front field indicated a chemical cost of about $3.00 for each barrel of additional oil.

Downhole Steam Generator

A downhole steam generator was designed, built and installed in a well at a depth of 2,300 feet in 1981, in the Tar Zone of the Wilmington field, California. The generator was designed to burn diesel fuel with air. The generator was in place 106 days, and 27,000 bbl of water as steam at about 450°F, 40 to 50 percent quality at 1,300 to 1,400 psi along with the combustion gases was injected into the reservoir. The heat generated varied from 2 to 4 million Btu per hour. During the run, 43 restart operations were carried out, of these 23 used glow plugs and 20 used the hypergolic liquid technique. (The use of glow plugs was discontinued after several failures. The hypergolic liquid technique worked well.) Run time was 78 percent, and there were 23 shutdowns due to compressor failures, computer and instrumentation interruptions and generator temperature uncertainty problems. The generator was removed from the well and inspection showed that metallic surfaces in the burner had degraded due to cracking, sulfidation and oxidation. The degradation had proceeded to a condition where uniform and complete combustion was no longer possible.

Thus, the feasibility of a downhole steam generator has been demonstrated but the investment and operating costs are not known. The advantages of the downhole steam generator over surface generation of steam are the elimination of the wellbore heat loss and the automatic injection of the combustion gases into the wellbore. The principal disadvantage as a constraint is the limitation on the size of the generator by the size of the casing. Corrosion could be a serious problem for the generator and well equipment at the bottom of the hole.

Hot Gas Injection

Hot gas (including steam) injection was used to recover a 19.5° API oil with a viscosity of 1,026 cp from a reservoir at a depth of 870 feet in the Carlyle field, Kansas. The equipment consisted of a high-pressure combustion chamber where the fuel -in this case No. 2 diesel fuel- is burned with compressed air. The hot combustion gases at temperatures up to 3,500°F flow into a steam generation drum where water is injected to cool the combustion gases to about 650°F and generate steam. The combustion gases and the steam flowed at a pressure of 900 psig and 650°F to the injection well. A water level was maintained in the steam generation drum and chemicals were added to the water to reduce corrosion.

The hot gases were injected into two to four producing wells in about the same manner as steam is applied in the cyclic steam stimulation process. Four cycles of hot gas injection were made on two to four wells. During the four cycles, a total of 1,941 million Btu of heat contained in 5,548 barrels of steam and 16,940 Mcf of combustion gases was injected. Total oil recovery was 9,646 bbl which was 8,492 bbl of additional oil over the estimated recovery by primary production.

Hot gas and steam injection incurs heat losses in the wellbore and presents difficulties in pumping viscous oil at high gas-to-oil ratios. Very viscous emulsions were observed during the project, but they responded to chemical treatment. It is doubtful if the test in the Carlyle field demonstrated the economic feasibility of the process because it is not known how oil production would have responded to additional cycles and whether the cyclic stimulation could have been converted into a drive process.

RELATIVE LEARNING STATUSES OF EOR PROCESSES

At this time thermal recovery (both fire- and steamflooding) are considered mature in that a great many of the problems have been solved, predictions and estimates of recovery can be made with a fair degree of accuracy and operating improvements are to be expected. Miscible flooding with carbon dioxide (CO_2) is an expanding technology, new applications are being announced frequently, and the technology can be considered as entering the mature stage. Polymer flooding with the partially hydrolyzed polyacrylamides and to some extent the polysaccharides, is nearing the mature stage as there have been economically successful projects. However, polymer flooding even though economically successful only increases oil recovery over that of waterflooding by a small percent of the original oil in place. Nevertheless the importance of polymer flooding technology should not be underestimated because the technology is an important part of surfactant flooding and possibly alkaline flooding. Polymer flooding is the first step towards solution of a most important problem in EOR -- the improvement of sweep efficiency.

Surfactant flooding could be on the threshold of maturity. It bears much promise for many reservoirs, but it is expensive and heavily "front loaded" with costs. In addition, while it appears to be an extremely complicated technology, it seems that most of the important problems in surfactant flooding have been identified. Much improvement must be made before surfactant flooding can be economic under present oil prices.

Alkaline flooding is the least advanced of the EOR technologies. No one seems to know why alkaline flooding appears to be successful in one field but not in another. Further, no one seems to be certain as to the mechanism or mechanisms by which alkaline flooding recovers oil. Much laboratory work remains to be done before alkaline flooding can be removed from the doubtful stage.

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Table 1. Field Trials of CO_2 Flooding with Costs Shared by the Department of Energy

	Operator	Location
1.	Columbia Gas Transmission Corp.	Granny's Creek Field, West Virginia
2.	Gulf Oil Exploration & Production Co.	Little Knife Field, North Dakota
3.	Guyan Oil Co.	Griffithsville Field, West Virginia*
4.	Pennzoil Co.	Rock Creek Field, West Virginia
5.	Shell Oil Co.	Weeks Island Field, New Iberia, Parish, Louisiana

*Project was stopped before CO_2 was injected.

Table 2. Field Trials of Polymer Flooding with Costs Shared by the Department of Energy

	Operator	Location
1.	Energy Resources Co. (ERCO)	Storms Pool Unit, Illinois
2.	Gulf Oil Exploration & Production Co. (Kewanee)	North Stanley Field, Oklahoma
3.	Shell Oil Co.	East Coalinga Field, California

Table 3. Field Trials of Surfactant Flooding with Costs Shared by the Department of Energy

	Operator	Location
1.	Cities Service Oil Co.	El Dorado Field, Kansas
2.	City of Long Beach	Wilmington Field, California
3.	Continental Oil Co.	Big Muddy Field, Wyoming
4.	Gary Operating Co.	Bell Creek Field, Montana
5.	Marathon Oil Co.	Robinson Field, Illinois
6.	Penn Grade Crude Oil Co.	Bradford Field, Pennsylvania
7.	Phillips Petroleum Co.	North Burbank Unit, Oklahoma

Table 4. Field Trials of Alkaline Flooding with Costs Shared by the Department of Energy

	Operator	Location
1.	Aminoil, USA	Huntington Beach Field, California
2.	City of Long Beach	Wilmington Field, California

Table 5. Field Trials of Thermal Recovery with Costs Shared by the Department of Energy

	Operator	Location
	Fireflooding	
1.	Cities Service Oil Co.	Bellevue Field, Louisiana
2.	Hanover Petroleum Co.	Little Tom Field, Texas
3.	Husky Oil Co.	Paris Valley Field, California
4.	Mobil GC Corporation (General Crude Oil Co.)	Lynch Canyon Field, California
	Steamflooding	
5.	Getty Oil Co.	Cat Canyon Field, California
3.	Husky Oil Co.	Paris Valley Field, California
6.	Santa Fe Energy Co. (Chanslor-Western Development Co.)	Midway-Sunset Field,California
	Steam Flooding with Ancillary Materials	
7.	CLD Group, Inc.	San Ardo & Midway-Sunset, Cat Canyon Fields, California
8.	Petro-Lewis Corp. & CORCO	Kern Front Field, California
9.	Stanford University Petroleum Research Institute	Kern River Field, California
	Downhole Steam Generator	
10.	Sandia National Laboratories	Wilmington Field,etc.,California
	Hot Gas Injection	
11.	Carmel Energy, Inc.	Carlyle Field, Kansas Eastburn (Cherokee)Field, Missouri

Table 6. Results of Field Trials of Steamflooding with Ancillary Materials

Identification	Field	Noncondensing Gas	Results
CLD Group, Inc.			
Test #1	Midway-Sunset	air	65,000 BO
Test #2	Cat Canyon	nitrogen	Minor oil recovery, decreased water cut
Test #3	Midway-Sunset	air	46,000 BO
Test #4	San Ardo	nitrogen	3,500 BO, decreased steam to oil ratio
Test #5	San Ardo	nitrogen	21,500 BO
Petro-Lewis Corp. & CORCO	Kern Front	none	96,000 BO
Stanford University	Kern River	nitrogen	In progress