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RESEARCH NEEDS TO MAXIMIZE ECONOMIC PRODUCIBILITY OF THE DOMESTIC OIL RESOURCE

FINAL REPORT

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RESEARCH NEEDS TO MAXIMIZE ECONOMIC PRODUCIBILITY OF THE DOMESTIC OIL RESOURCE

PART I. LITERATURE REVIEW AND AREAS OF RECOMMENDED RESEARCH

By Min K. Tham, Thomas Burchfield, Ting-Horng Chung, Phil Lorenz, Rebecca Bryant, Partha Sarathi, Ming-Ming Chang, Susan Jackson, and Liviu Tomutsa

PART II. EOR FIELD PROJECTS REVIEW

By Dwight L. Dauben

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ABSTRACT

NIPER was contracted by the U. S. Department of Energy Bartlesville (Okla.) Project Office (DOE/BPO) to identify research needs to increase production of the domestic oil resource, and K & A Energy Consultants, Inc. was subcontracted to review EOR field projects. This report summarizes the findings of that investigation.

Professional society and trade journals, DOE reports, dissertations, and patent literature were reviewed to determine the state-of-the-art of enhanced oil recovery (EOR) and drilling technologies and the constraints to wider application of these technologies. The impacts of EOR on the environment and the constraints to the application of EOR due to environmental regulations were also reviewed. A review of well documented EOR field projects showed that in addition to the technical constraints, management factors also contributed to the lower-than-predicted oil recovery in some of the projects reviewed.

DOE-sponsored projects were reviewed, and the achievements by these projects and the constraints which these projects were designed to overcome were also identified.

Methods of technology transfer utilized by the DOE were reviewed, and several recommendations for future technology transfer were made.

Finally, several research areas were identified and recommended to maximize economic producibility of the domestic oil resource.

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EXECUTIVE SUMMARY

In 1990, the United States imported more than 42% of the oil the Nation consumed. This massive importation of crude oil contributes significantly to the Nation's trade deficit. To reduce the rate of increase in crude oil imports and to reduce vulnerability to oil supply disruption, the U. S. Government, as described in the National Energy Strategy, is using research and development funding to promote the development of advanced recovery technologies (advanced secondary recovery and enhanced oil recovery) to maximize the economic producibility of domestic crude oil. The strategy for accomplishing this was described in the DOE's Oil Research Program Implementation Plan, which is now known as the National Energy Strategy - Advanced Oil Recovery Program Implementation Plan (NES -AORPIP). However, specific areas of research required to achieve the goals of this strategy were not identified in the AORPIP. The objective of this project was to identify constraints to the expansion of enhanced oil recovery (EOR) in the United States and to propose areas of research needed to achieve the objectives of the AORPIP. In this report, the technical constraints to economic producibility of the known domestic oil resource are identified based on reviews of laboratory and field research projects in EOR technologies, and the research efforts required to overcome these constraints are proposed. Constraints to transferring the technology are also examined in this report. Although other constraints (financial resources, low or unstable prices, and lack of markets) are very important, they are not addressed in this report because they are controlled by a complex mixture of market forces and political and regulatory factors.

This report is divided into two parts for clarity. Part I presents a state of the art review, based on research performed in the laboratory and significant field results, and Part II is a comprehensive review of EOR field projects.

In Part I, the scientific literature published by professional societies, U. S. DOE, trade journals, and universities was reviewed to assess the state of the art of various oil recovery and environmental technologies to arrive at a list of constraints to wider application of advanced oil

recovery to increase domestic oil production. DOE-sponsored research projects were also reviewed to determine if these projects are addressing these constraints.

Gas Enhanced Oil Recovery

Gas displacement, predominantly carbon dioxide (CO_2) EOR, accounts for about 27% of enhanced oil recovery (EOR) production. CO_2 EOR is the method of choice where inexpensive CO_2 is available and when the screening criteria are satisfied. Nevertheless, many technical problems and uncertainties still exist in gas displacement technologies. Poor sweep efficiency and lack of predictability are major problems.

After more than a decade of research on mobility control problems, an effective solution has yet to be found. The major factor is that reservoir features and multiphase flow in porous media are difficult to describe accurately. Although numerous laboratory studies have been conducted on foam behavior in porous media, simulation, foam rheology, foam stability, surfactant adsorption, and applications in EOR, no successful field test on foam applications for gas mobility control has been reported. Long-term research dedicated to fundamental studies on multiphase flow in porous media is needed.

The lack of predictability stems primarily from the lack of ability (1) to characterize reservoir heterogeneities adequately; (2) to describe recovery mechanisms such as molecular diffusion, oil swelling, and incomplete mixing between CO_2 and crude oil; and (3) to characterize crude oil heavy fractions.

The recommended areas of research for Gas EOR are as follows:

Near-term

1. Development of improved methods to predict phase behavior.
2. Development of a channel-block method for profile modification.
3. Development of improved prediction techniques for asphaltene precipitation.
4. Application of horizontal well technologies to gas EOR.

Mid-term

1. Investigation of the effect of different scales of heterogeneity on recovery.
2. Investigation of the effect of incomplete mixing and phase behavior in porous media on recovery efficiency.
3. Development of improved compositional simulator for gas flooding.

Long-term

1. Development of novel methods for gas mobility control.
2. Investigation of the fundamental properties of foam.
3. Study the characteristics of multiphase flow in porous media.

Surfactant Enhanced Oil Recovery

Surfactant flooding is the most adaptable to U.S. reservoirs of all the EOR processes. A review of prior field projects identifies reservoir heterogeneity, excessive chemical loss, inherent design weaknesses, and problems with polymer propagation as some of the constraints to surfactant EOR application. Considerable advances have been made in recent years in designing surfactant molecules and surfactant formulations that can withstand high salinity (20% NaCl) and temperature (200° F). By selecting salinity-tolerant surfactant, eliminating alcohols, reducing adsorption by addition of alkali, and using chemical gradients, slug integrity is being maintained successfully. The state of the art in chemical EOR simulation has also been advanced considerably. Yet, additional research efforts are needed to reduce the costs of chemical slugs, before they can be applied extensively in the field.

The recommended areas of research for surfactant EOR are as follows:

Mid-term

1. Improve reservoir evaluation and develop techniques to overcome reservoir heterogeneities..
2. Development of optimized (with respect to effectiveness, stability, and cost) surfactant EOR processes for application in high-salinity, high-temperature reservoirs.
3. More cost/benefit optimization should be studied for low-tension polymer floods.
4. The behavior of mixed surfactants should be explored more thoroughly.
5. Development of method to prevent surfactant-polymer incompatibility.

Long-term

1. The role of molecular structure should be studied further to assist in the design of surfactants.
2. Alternative surfactant types should be reviewed to determine which deserve more extended testing and development of manufacturing procedures at reduced cost.

3. Various kinds of (salinity, alcohol, etc.) gradients should be investigated. In particular, consideration should be given to combined gradients.

Alkaline Flooding

For all its economic attractiveness, alkaline flooding is not being used very actively. High chemical consumption and high operational costs resulting from scale formation are the greatest impediments to its use. With incorporation of surfactants in alkaline slugs, emphasis on mobility control, and the demonstration that high acid content is not a prerequisite for successful oil recovery, alkaline flooding can be an economical EOR process and may be applicable to a larger number of reservoirs than formerly thought. Unfortunately, few field tests have been performed to demonstrate the viability of this new development, and scarcely any public information is available.

The recommended areas of research for alkaline flooding EOR are as follows:

Near-term

1. Investigation of the use of an extended "salinity requirement diagram" (two- or three-dimensional concentration scans of alkali, surfactant, and salt) to maximize oil mobilization.
2. Study of injection strategies (surfactant, alkali, polymer).

Mid-term

1. More study of specific ion effects, and development of optimal mixtures of alkalis. Design of a means to stabilize silicate solutions at high values of SiO_2/Na_2O.
2. Investigation of the effects of alkalis on critical micelle concentration, cloud point, and partitioning of surfactants; and on the mechanical entrapment of polymers.
3. Demonstrate technical feasibility of alkaline-surfactant-polymer flooding in well documented field pilot tests.

Microbial Enhanced Oil Recovery

Microbial enhanced oil recovery (MEOR) has been recognized as a potentially cost-effective method for stimulating stripper well production. MEOR is one of the most economically viable EOR processes available. Lack of well-documented field tests, misconceptions of MEOR recovery mechanisms, and a tendency to evaluate MEOR in terms of the understanding of traditional EOR mechanisms are hampering the widespread acceptance of this EOR process. Recent advances include delineation of recovery mechanisms and an improved understanding of the activities of microbes and metabolites at oil/water and oil/water/rock interfaces. Mathematical models incorporating the many complex chemical, microbiological, and transport phenomena taking place in a MEOR process are being developed. The results of a few MEOR field projects, some well documented, are reported in the open literature.

The recommended areas of research for Microbial EOR are as follows:

Near-term:

1. Perform well documented field tests, especially in reservoirs with substantial remaining oil saturation.
2. Development of low-cost, consistent, and readily available nutrients.
3. Development of profile modification and well stimulation methods.

Mid-term:

1. Development of salinity- and temperature-tolerant microbes.
2. Improvement of simulator for MEOR processes.

Long-term:

1. Improved understanding of recovery mechanisms for various microbial techniques.

Polymer Flooding

Even with low oil prices, polymer flooding is being practiced successfully and profitably. It is a technically mature technology. The AORPIP identified polymer flooding as a potential process that can assist in achieving near-term objectives of DOE's Advanced Oil Recovery Program. Recent advances include improving injectivity of biopolymer, introduction of polymers that can withstand higher temperatures (up to 250° F) and salinities (up to 18% NaCl), and improvements in injection strategies (early application of polymer flooding).

The areas in which near-term research can lead to improvements in oil recovery by polymer flooding are as follows:

Near-term

1. Design of injection protocol. This includes using multiple polymer types in successive slugs or blends and optimization of slug size.
2. Improved products for better injectivity, range of propagation, quality control, and stability at high temperature and salinity. Develop cost-effective products.

3. Determine factors (especially geologic) affecting injectivity and propagation of polymer.
4. Development of environmentally acceptable biocides for use in polymer flooding.

Profile Modification

Modification of production or injection profiles, usually near-wellbore treatment by gelled polymers, has been used in the field for more than 20 years. Like polymer flooding, profile modification is considered a mature technology, and it is one of the advanced secondary recovery methods proposed by DOE to have the potential to arrest the rapid abandonment of stripper wells in the near-term. Considerable research is being performed to achieve in-depth treatment. The effectiveness of these new in-depth treatment methods has not been fully tested in the field. It is important to define the reservoir problems to be addressed in designing a specific treatment.

The recommended areas of research for Profile Modification are as follows:

Near-term

1. Accumulation of more extended data on the influence of reservoir parameters on properties of gels (especially gelation kinetics).
2. Improved models for prediction/design of profile modification process.

Mid-term

1. Improved accuracy in treating the target zone without damage to productive zones.
2. Development of methods for achieving the desired effect over an extended region.

Long-term

1. Delineation of rheological properties of gels and pregels.
2. Develop a better understanding of the differences between behavior of gel in bulk and in porous media.
3. Improved crosslinking systems which are nontoxic and environmentally benign.
4. Improved gel systems which are stable at high temperature and salinity.

Thermal Enhanced Oil Recovery

Thermal EOR processes, especially steamflooding, account for more than 71% of the EOR production in the United States. Environmental restrictions, higher operating costs, and lower oil prices are limiting the expansion of steamflood projects in California, where most of the thermal EOR projects are now operating. Improvement in reservoir conformance, especially with foam, and improvement in thermal efficiency are the two most important areas of research in recent years. High operating costs, low oil prices, and environmental regulations are the constraints restricting expansion of steamflooding operations.

The recommended areas of research for Thermal EOR are as follows (Additional recommended areas of research are given in chapters 8 and 15.):

Near-term

1. Improvement in injection profile control techniques.
2. Improvement in mobility-control techniques: steam foam process.
3. Improvement in steam quality measurement and control.
4. Development of reliable methods for determining phase splitting at the steam distribution system branches and techniques to ensure a relatively even flow splitting between branches.

Mid- and long-term

1. Development of improved method of reservoir characterization.
2. Development of techniques to steamflood consolidated sands.
3. Research on the best way to steamflood light oil reservoirs to maximize recovery.
4. Development of improved techniques to steamflood fractures and/or dolomite reservoirs.

Infill Drilling

Infill drilling, whether using vertical or horizontal wells, has the potential of increasing the reserves of domestic reservoirs. Recent advances in horizontal drilling and reservoir engineering technologies have increased this potential even further by reducing costs of drilling and the improved predictability of oil production. In essence, the petroleum industry has been identifying constraints and is solving these problems; however, for infill drilling to be economical and successful in increasing reserves, the production characteristics of the reservoir need to be clearly defined. The potential of applying horizontal wells to improve EOR recovery efficiency needs to be investigated further. At present, no general criteria for selecting reservoirs for successful infill drilling have been developed, and each reservoir must be characterized and analyzed individually; this is another area that needs further research.

Reservoir Characterization

Reservoir heterogeneities can adversely affect the performance of EOR field projects as is shown in Part II of this report. Performing reservoir characterization in a cost-effective manner should be a goal of any field development project; this is especially true for EOR applications where different slug sizes are being used. Reservoir characterization is a complex and difficult task that requires information from diverse sources on a wide range of scales and the integration of analyses from a broad range of disciplines including geoscientists, physical scientists, and engineers. The constraints in reservoir characterization are due to: (1) the complexity of the rock and fluid distributions and (2) typically inadequate information available even for the most ambitiously sampled reservoirs.

The challenges in reservoir characterization include: (1) obtaining sufficient detailed reservoir information; (2) constructing predictive models of spatial distribution of reservoir characteristics in the interwell area; (3) incorporating the abundant semi-quantitative information available from the reservoir into simulation models and (4) developing scaling or averaging procedures for determining representative simulator grid block values.

To achieve cost-effective, accurate reservoir characterization, the following research areas need to be pursued:

Near-term

1. Development of computer-based database management systems that allow data from all disciplines, at all scales, including non-numeric information to be easily integrated and output to a wide range of end-user applications.
2. Development of methodology for systematic reservoir characterization that includes systematic data collection, analyses, integration, and utilization of all types of data (including semi-quantitative) from various sources.
3. Innovative methods to extract reservoir properties from engineering data, especially data from older reservoirs.
4. Predictive models of the spatial distribution of reservoir characteristics in the interwell area. The development of these models requires large amounts of quantitative geologic and petrophysical information from reservoir analogs.
5. Development of a reservoir classification system and the determination of the degree to which properties can be transported from one reservoir to another.
6. Measurement of accurate relative permeability data and development of correlations.

Mid-term

1. The development of diagenetic models that predict the spatial distribution of diagenetic phases within specific reservoir strata on the interwell to field scale.
2. Documentation and model development of the spatial distribution of geochemical characteristics within a reservoir.
3. Increased penetration distance and vertical resolution of petrophysical characteristics measured by well logging tools.
4. Integration of seismic data (megascale) with interwell measurements (macro-scale) and core measurements macro- to micro-scale.
5. Scaling-up procedures of various reservoir properties including relative permeability, for determining simulator grid block values.

Long-term

1. Determination of reservoir permeability from geophysical techniques including acoustic logging and crosshole tomography.
2. Integration of theoretical seismic model studies with field data.
3. Application of well testing to more heterogeneous reservoirs.
4. Improved geophysical techniques for reservoir definition at a reasonable cost.

Environmental Impact of EOR

The U. S. DOE has sponsored a number of projects evaluating the impact of EOR operations on the environment. The general conclusion has been that application of EOR processes (with the exception of thermal EOR) in oil fields will not be any more detrimental to the environment than primary production and waterflooding operations. Successful EOR operations reduce the need to handle large quantities of produced fluid by reducing water-oil ratios. Since produced water constitutes 98% of the waste in oil and gas exploration and production operations, reduction in volume of produced water definitely lessens the potential for harming the environment. On the whole, regulations governing air and water quality are sufficient to protect the environment in EOR operations.

The recommended areas of research are:

1. Update the Environmental Regulations Handbook for Enhanced Oil Recovery.
2. Establish a consortium of government, industry and environmental groups to define and to work out problems.

Technology Transfer

A critical component in increasing domestic production through application of EOR methods is the transfer of information to the producers who need the technology. A major goal is the development of a technology transfer program which would have a significant impact in the application of EOR methods to increase the domestic production. A technology transfer program should provide information for use by all producers regardless of size; however, it should also be targeted for a group(s) which best meets the need of the selected criteria. The larger companies should be targeted if the principal criterion is the recovery of the maximum amount of oil; the smaller companies should be selected if the principal criterion is to prevent the loss of oil reserves by the early abandonment of wells. A mix of these criteria should be considered in a final analysis. Therefore, our recommendation is to target the technology transfer program to major and intermediate-to-larger independent producers.

Existing technology transfer methods were reviewed, and recommendations for improving DOE's effectiveness in transfer of advanced oil recovery technology are as follows:

1. Refocus the current research program on the critical areas as recommended in this report and on research programs that address the needs of the operators.
2. Target technology transfer efforts to the major and intermediate-to-larger independent producers.
3. Strengthen the existing technology transfer program.
4. Introduce new approaches to technology transfer:
   (a) Improve access to commercial publications through an on-line service, and
   (b) introduce interactive teaching of specialized courses through video communication.

EOR Field Projects

Part II of this study was designed to identify the technical constraints which have been determined as a result of field testing. A study of 84 field projects was conducted to determine the constraints which limit the recovery from enhanced oil recovery (EOR) projects. The reviews were based upon the open literature, Department of Energy (DOE) publications, previous evaluations of the DOE cost-shared EOR projects, and corporate experience. This field-derived information provides important input in the total assessment of the constraints which currently limit EOR potential.

Two broad categories of constraints appear to affect all of the EOR processes in the field: (1) reservoir heterogeneity-mobility control and (2) downhole completion-operations.

Reservoir Heterogeneity, Mobility Control. About 30% of the total identified constraints fit into this category. Reservoir heterogeneities have a major impact on the sweep efficiency of injected fluids. Because of the high cost of injectants in EOR projects, it is critical that a good understanding of the reservoir exists and that sweep efficiency is maximized. Mobility control is a closely associated parameter since it, along with reservoir heterogeneities, controls the level of sweep efficiency achieved. The common occurrence of these two closely associated parameters suggests an important area for additional research.

Downhole Completions, Operations. This category affects all of the EOR processes but has particular significance for in situ combustion technology. Problems in these categories primarily affect costs, which ultimately affect oil recovery. Although additional research is needed to develop improved equipment and procedures, the major efforts should be to use existing technology more effectively.

The major technical constraints have been identified for each of the processes based upon field results. It is emphasized that the constraints derived from this source are not all inclusive. Some of the problems which are known to exist may not be evident from field tests. The following are the major technical constraints for each process based upon field data.

Polymer Flooding

These technical constraints were derived from evaluation of polymer floods, crosslinked or gelled polymer systems, and micellar-polymer flooding.

(a) Polymer Propagation. One of the most prevalent characteristics in chemical projects has been the failure of polymers to propagate through the reservoir. Plugging has been a common occurrence, and polymer has been frequently injected above the pressure parting level to achieve a minimum level of injectivity.

(b) Degradation. The commonly used polyacrylamides and the xanthan biopolymers are subject to degradation from several mechanisms.

(c) High Temperature, High Salinity Environment. The current polymers become unstable or ineffective in reducing fluid mobility under conditions of higher temperature and higher salinities.

Profile Modification

The technical constraints for polymers are also applicable for profile modification. In addition, attention is needed on establishing better design criteria. These include: (1) better definition of reservoir characteristics which are suitable for profile modification, (2) consideration of improved placement techniques, and (3) improved definition of critical design parameters (penetration requirements, degree of permeability reduction required). Additional concerns are the long term stability of polymers and gels, and the propagation characteristics of sequentially injected polymer and crosslinking agents.

Micellar-Polymer Flooding

(a) Excessive Chemical Loss. Research is needed to develop and to evaluate surfactant systems which can be tailored to work within the existing ionic environments of a specific reservoir.

(b) Process Design, Operations. Field tests show that these categories of constraints greatly impact costs. Through careful design of the project and close monitoring, many of the problems in these categories can be eliminated.

(c) Inherent Design Weaknesses. The micellar-polymer process has some inherent weaknesses. One of the major problems arises from the need for two dissimilar fluids to travel in sequence and to remain intact through long interwell distances. These mechanisms, coupled with the propagation problems for the polymers, tend to make the process applicable only for close spacing. Innovations in technology are needed.

Alkaline Flooding

Alkaline floods have performed poorly in the past. Major constraints are:

(a) Excessive Consumption. The basic problem is that the injected alkaline fluids are highly reactive with the divalent ions in the formation water, divalent ions associated with clays, and with mineral constituents such as gypsum. Laboratory studies incorporating an alkaline fluid, an added cosurfactant, and polymer have shown promise. Additional research is needed.

(b) Operational Problems. Major operational problems in the field have been the occurrence of scale in offsetting producers. These can be largely controlled by scale inhibition programs and periodic acid treatments.

Gas Injection

Gas injection projects considered in this study include CO_2 miscible displacement, CO_2 immiscible displacement, gravity stable displacement, and nitrogen injection.

(a) Reservoir Heterogeneity. Field tests show that reservoir heterogeneities have had a major impact in the poor sweep efficiencies that have been realized in many projects.

(b) Mobility Control. The high mobility of injected gas is an additional factor in the poor sweep efficiencies observed in field projects.

(c) Injectivity. Field tests show injectivity is often lower than would be predicted from laboratory or simulation studies. An awareness of these characteristics is needed in the design of new projects and in the development of better methods for improving sweep.

(d) Operations. Field tests show the major operational problems to be corrosion control for CO_2 projects and artificial lift problems which occur with the breakthrough and production of significant quantities of gas.

Steam Injection

Emphasis in this evaluation was the steamdrive process. Steam injection-production on a single well was considered an important part of the total process.

(a) Gravity Segregation. Gravity segregation appears to be the dominate problem in steam injection projects.

(b) Reservoir Heterogeneity. The effects of reservoir heterogeneities upon performance are similar to those of other processes. The high mobility of steam tends to accentuate an existing reservoir heterogeneity problem.

(c) Downhole Completions. Field tests show a considerable number of operational problems such as sand control and the failure of thermal packers.

(d) Steam Generation. The cost for generating steam in a new project is a major factor.

Additional research studies are warranted to support the extension of commercial steamflood projects into other geographic areas.

In Situ Combustion

In situ combustion technology has high potential for increasing recovery of heavy oils, including those which may not be suitable candidates for steam injection. However, field results have been discouraging, and there have been few economic successes. The following are the major technical constraints.

(a) Reservoir Heterogeneity. Field results show that reservoir heterogeneities impact in situ combustion projects more than any other process.

(b) Downhole Completions. The major problems in this category are erosion and corrosion related to sand production in the producers, burnback of the combustion front in the injection wells, and combustion front breakthrough in producing wells.

(c) Operations. Corrosion and oil treating are the major problems in this category.

CHAPTER 1

INTRODUCTION

In 1990 the United States imported more than 42% of the oil the Nation consumed, according to The National Energy Strategy (1991). This massive importation of crude oil contributes significantly to the Nation's trade deficit, "with disturbing implications for national security, international competitiveness, the balance of payments, employment, and the standard of living" (DOE, 1990). To reduce the rate of increase in crude oil imports, and to reduce vulnerability to oil supply disruption, the U. S. Government, as described in the National Energy Strategy, is using research and development funding to promote the development of advanced recovery technologies (advanced secondary recovery and enhanced oil recovery) to maximize the economic producibility of domestic crude oil. Advanced secondary recovery methods are those processes which improve waterflood sweep efficiency, and enhanced oil recovery methods are those processes which improve displacement sweep efficiency. The foundation for these research and development efforts is based on the Department of Energy's Oil Research Program Implementation Plan (DOE, 1990). This program is now known as the National Energy Strategy – Advanced Oil Recovery Program (NES-AORP).

The Advanced Oil Recovery Program Implementation Plan (AORPIP) was prepared by the Department of Energy in April 1990 to arrest the increased reliance on imported oil through research and development and to provide direction for this research and development effort. With the objective of maximizing the economic producibility of the domestic oil resource base, the plan in the near-term attempts to preserve access to known reservoirs with high potential of oil production; in the mid-term, develops, tests, and transfers the best currently defined advanced technologies to operators to improve oil recovery; and in the long-term, develops a fundamental understanding to define new recovery techniques for the oil left after application of the most advanced, currently defined mid-term processes, and supports universities to sustain the Federal Government's commitment to education. This plan aims at reducing the technical and economic constraints on producibility of the remaining oil resource and broadens the traditional DOE role of supporting mainly high-risk, long-term research. As a consequence of this change in research direction, there is a need for the Bartlesville Project Office (BPO), as the DOE lead field office for enhanced oil recovery, to review current DOE-supported research programs and determine how best to adjust them to comply with the new AORP.

The objective of this project is to identify constraints to expansion of enhanced oil recovery (EOR) in the United States. Mungan (1990) defined constraints to include "lack of expertise (technical constraints), lack of staff (technology transfer constraints) or financial resources, low or unstable prices, lack of markets and competition for exploration or acquisition." In this report, the technical constraints to economic producibility of the known domestic oil resource are identified through reviewing laboratory and field research projects in EOR technologies, and the research areas required to overcome these constraints are proposed. The technology transfer constraints are also examined in this report. Although the other constraints, financial resources, low or unstable prices and lack of markets, are very important, these constraints will not be addressed in this report because these are controlled by a complex mixture of market forces, political and regulatory factors.

The National Petroleum Council (NPC) studies of 1976 (NPC, 1976) and 1984 (NPC, 1984) listed the constraints impeding the widespread application of enhanced oil recovery (EOR) processes in the United States; however, economic changes and technical developments in recent years have altered the situation significantly. Low-cost EOR processes such as microbial, (Bryant et al., 1990); alkaline-surfactant-polymer, (French and Burchfield, 1990); in-depth polymer permeability modification (Mumallah, 1987; Sydansk, 1990) and flooding; and low tension polymer flooding (Kalpakci and Arf, 1990) have been proposed as possible candidates to be used as cost-effective EOR methods. Other methods of improving recovery from existing fields, including targeted infill and horizontal drilling, are also being included now as strategies for recovering additional oil. A thorough review of the literature is needed to incorporate these advancements in technology into any document that enumerates the research needs in EOR.

This report is divided into two parts for clarity. Part I concentrates on research performed in the laboratory, while Part II examines field EOR projects.

Gas EOR processes are producing 20% of the domestic EOR production, and the use of CO_2 and hydrocarbon flooding is expanding. Limited availability of CO_2 is partially responsible for the slow rate of expansion. Technical constraints identified in the 1984 NPC study such as reservoir heterogeneity and problems with mobility control are also partially responsible. In recent years, considerable research on improving mobility control has been performed, and some of the work is reviewed in chapter 2.

The high cost of chemicals used in surfactant flooding limits the slug size of chemicals that can be incorporated into a surfactant EOR design. Many of the constraints identified in the NPC study are related to this slug size limitation. Recent research has broadened the range of applicability of surfactant flooding as far as salinity and temperature are concerned, and these advances are reviewed in chapter 3.

Alkaline flooding has always being proclaimed as a potential low cost EOR process; however, high chemical consumption has prevented successful field applications. Addition of a supplementary surfactant and use of weaker alkali to overcome consumption have revived interest in this EOR method. The state of the art in alkaline flooding is reviewed in chapter 4.

Chapter 5 discusses another low cost EOR method that relies upon the injection of microbes and inexpensive nutrients to enhance the recovery of remaining oil. Research on microbial enhanced oil recovery (MEOR) methods has advanced the scientific understanding of this recovery method to a level that has won respectability for this otherwise misunderstood method.

Chapters 6 and 7 review two of the advanced secondary recovery methods, polymer flooding and profile modification, which were considered by the AORPIP to have potential near-term application in arresting the rate of abandonment of marginal wells.

Thermal EOR processes, especially steamflooding, account for more than 73% of the EOR production in the United States. Environmental restrictions, higher operating costs and lower oil prices are limiting the expansion of steamflood projects in California, where most of the thermal EOR projects are now operating. Though thermal EOR processes contribute more than 6% of the total U. S. oil production, the technology is far from being mature. Considerable efforts are being expended to improve the economics of thermal EOR, to improve steamflood mobility control, and to advance the oil production and pollution control technologies. The progress in these areas is reviewed in chapter 8.

Recent advancements in horizontal well drilling, completion, stimulation, and reservoir engineering technology have added life to the domestic petroleum industry. Advancements in horizontal well technology and possible applications in EOR processes are discussed in chapter 9. Recent advances in infill drilling are also discussed in this chapter.

The remaining constraints that need to be overcome before commercialization of these production methods can become a reality and areas of research that are needed to overcome these constraints are also identified in these chapters.

Reservoir characterization, or the lack of it, is identified as a constraint to successful field tests of EOR processes. In the 1980s, a large number of research projects were initiated to advance the technology of reservoir characterization. A review of the state of the art in reservoir characterization is given in chapter 10. In the 1990s, environmental issues will become an even more dominant issue than before, and in recognition of this, the AORPIP identified environmental technology as an area of supporting research. Chapter 11 discusses the potential impact of EOR projects on the environment and the constraints of environmental regulations on future expansion of EOR.

Since the early 1970s, the DOE Bartlesville Project Office and its predecessors have been funding EOR research at universities and national laboratories that has contributed significantly to the development of EOR processes. Notable achievements are the advances in basic understandings of surfactant-polymer, polymer, steam, gas, microbial, and gelled polymer technologies. Realignment of the DOE oil research program to emphasize research with near-term goals as outlined in the AORPIP will require a review of projects being funded by the DOE through the BPO and evaluation of these projects in the light of the AORPIP and the state of the art in oil recovery technology. A proper mix of near-, mid-, and long-term projects is needed to achieve the objectives of the plan. This can best be accomplished by evaluating the achievements of previous programs to identify those that address the near- and mid-term goals. The DOE-funded supporting research and the achievements resulting from these projects are reviewed in chapter 12.

One of the important aims of the AORPIP is to help independent oil producers by transferring the technology obtained from the research and development program to them. This is an important goal because independents produce almost 50% of the oil in the United States. This trend will grow as more and more major oil companies sell their marginal domestic fields to smaller independent operating companies. Unfortunately, many independents may not be capable of using and benefitting from advancements in the technology. They may be unable to utilize this technology even if "transferred" to them. To have a research and development plan that is targeted toward independents, technologies that can best be utilized by most independent operators and the best technology transfer medium must be determined with the sophistication of the technology and the recipients of this technology in mind. Chapter 13 discusses the technology transfer methods currently used by DOE, some proposed additional programs that can optimally achieve these goals, and methods for technology transfer that will have to be identified and proposed. Many of the EOR processes require considerable front-end investments, and the ability of independent operators to finance such EOR projects is also considered in this chapter.

DOE has also sponsored a number of cost-shared field projects, which have contributed significantly to the development of EOR processes. The experience gained from those cost-shared projects points out the importance of proper reservoir characterization in ensuring the success of EOR projects and many other field-related problems not obvious from laboratory research. The mid-term plan in the AORPIP calls for considerable field work to be cost-shared by states and/or operators. Reviewing the cost-shared projects of the late 1970s will assist in avoiding the pitfalls encountered during the implementation of those projects. The most often mentioned concerns that operators have raised about cost-shared projects have been the long delays between beginning of contract negotiations and initiating projects and the amount of paperwork involved. Valuable experience from conducting those projects should be considered in planning future field projects. Part 2 of this report reviews a number of DOE- and industry-funded EOR field projects and identifies the technical and management related problems that prevent these projects from being proclaimed successful.

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RESEARCH NEEDS TO MAXIMIZE ECONOMIC PRODUCIBILITY OF THE DOMESTIC OIL RESOURCE

PART I
LITERATURE REVIEW AND AREAS OF RECOMMENDED RESEARCH

CHAPTER 2
GAS ENHANCED OIL RECOVERY: STATE OF THE ART

By Ting-Horng Chung

INTRODUCTION

Gas displacement, both miscible and immiscible, accounts for about 27% of enhanced oil recovery (EOR) production. In the United States, according to the *Oil & Gas Journal* 1990 worldwide survey, 91 gas EOR projects were active in 1990, and 34 projects were planned for 1990 through 1992 (Oil & Gas J., Apr. 23, 1990). The DOE EOR Project Database listed 303 gas EOR projects by the end of 1989 (Pautz and Thomas, 1990). Oil production from carbon dioxide (CO_2) and low-molecular-weight hydrocarbon (HC) miscible/immiscible gas injection projects is rapidly increasing in the U.S., as the *Journal's* exclusive survey shows. This survey reported that at the beginning of 1990, production by gas miscible EOR was estimated to be 96,600 barrels per day , which was 30% above that predicted by the 1984 National Petroleum Council (NPC) study (Pautz and Thomas, 1990). The use of CO_2 has grown significantly since the early 1980s, especially in the Permian Basin and the Rocky Mountain region, as reliable supplies of CO_2 have become available. Gas injection will become the major EOR method within this decade as more offshore oil fields and fields in Alaska approach mature stages of secondary recovery. Nevertheless, many technical problems and uncertainties still exist in gas displacement technologies. Poor sweep efficiency and lack of predictability are major problems (NPC, 1984). The development of effective methods to solve these problems is critical to boost gas EOR applications.

Gas EOR processes include the injection of CO_2, nitrogen (N_2), flue gases, and hydrocarbon gases under miscible or immiscible conditions. Because of this variety of choice, gas EOR methods can be applied in a wide range of reservoir conditions. For example, nitrogen gas can be used for high-pressure (>4,500 psi) light oil (>45 ° API gravity) recovery (Clancy et al., 1983; Hudgins et al., 1990); carbon dioxide is capable of miscibly displacing many crude oils (>25 °API gravity) under common reservoir conditions (p>1,500 psia) and, thus, can be used for most reservoirs; liquid petroleum gas (LPG) is miscible with crude oil at relatively low pressures and, thus, can be used for shallow reservoirs. Carbon dioxide has also been used for heavy oil recovery under immiscible conditions (Saner and Patton, 1983; Kantar et al., 1985). Thus, in general, the restrictions are fewer for gas EOR methods than for other EOR methods. Constraints to applications of gas EOR methods are outlined in table I-1. The major screening factor for gas EOR methods is gas source. Although supplies of any of these gases can usually be provided, the cost and the quantity of an injection gas are of major concern. Hydrocarbon gases (C_1, C_2, C_3,

TABLE I-1. - Comparison for different gas injections

Injection gas	Advantages	Problems and constraints	Current or potential applications
CO_2	1. Natural source is available in Rocky Mountain region 2. Miscible criteria are achievable for most reservoirs 3. Higher displacement efficiency due to oil swelling and viscosity reduction 4. Applicable for heavy oil recovery 5. Non-flammability, and non-toxicity	1. Limited natural source 2. Corrosion problem for transportation and injection facilities, and well tubing 3. Formation damage due to acidization 4. Gas mobility control problem 5. Cost of separation in produced gases (offset if recycled) 6. Asphaltene precipitation	1. Miscible or immiscible displacement for light and heavy oil reservoirs, where CO_2 source is available (e.g., West Texas, New Mexico, Rocky Mountain region)
N_2	1. Source has no limitation 2. Low cost 3. Non-corrosivity	1. Higher MMP (miscibility is not achievable for most reservoirs) 2. Low displacement efficiency 3. Cost of separation in produced gases (offset if recycled) 4. Gas mobility control problem 5. Nitrogen asphyxia	1. High pressure miscible displacement 2. Condensate reservoir cycling 3. Used for HC or CO_2 slug chase gas, pressure maintenance, gas-cap gas production 4. Attic oil production
Hydrocarbon gases	1. Miscible with reservoir oil (depends on gas composition) 2. Source is available in oil fields 3. Gas separation may not be needed	1. Limited quantity of available HC gases 2. More expensive in gas purchase 3. Flammability 4. Accumulation of toxic gases (H_2S, etc.)	1. Miscible or immiscible oil displacement in Alaskan and offshore oil fields 2. Shallow oil recovery

and C_4) are more expensive than carbon dioxide, nitrogen, or flue gas, and available quantities of these gases are usually insufficient for large-scale field floods. Thus, HC gas is usually injected in a slug and driven by nitrogen gas. Nitrogen gas sources are not limited, and cost is relatively lower than that of HC or CO_2. Thus, N_2 is usually used as chase gas for HC or CO_2 slug injection. However, the displacement efficiency of N_2 gas is lower than that of CO_2 or HC gases. The N_2-miscible displacement mechanism involves the vaporization of solvents (ethane, propane, and butane) from crude oil to generate an oil-miscible front to displace residual oil. Thus, the presence of light hydrocarbons (C_1, C_2, C_3, or C_4) in reservoir oil is necessary for nitrogen to achieve miscibility.

Carbon dioxide is more effective in displacing oil at relatively lower pressures than nitrogen and lean gas because of capabilities of hydrocarbon extraction, oil swelling, and viscosity reduction. In most applications as an oil recovery agent, carbon dioxide exists as a supercritical fluid, which enhances its solvency power for high-molecular-weight hydrocarbons. Analyses of the oil displacement fronts in laboratory CO_2-coreflooding experiments have revealed the presence of substantial amounts of hydrocarbons in carbon numbers ranging from C_5 to C_{35} (Holm and Josendal, 1974; Orr and Taber, 1981). Thus, for CO_2 displacement, the presence of light hydrocarbons in reservoir oil is not necessary to achieve high oil recovery (Holm and Josendal, 1974).

The controlling variable in gas miscible displacement is the pressure required to achieve miscibility, known as the minimum miscibility pressure (MMP). The MMPs for these gases follow the sequence: LPG $< CO_2 < C_2 < C_1 < N_2$. In most cases, miscibility is achieved by a dynamic (multiple-contact) process involving interphase mass transfer. Therefore, sufficient contact between injection gas and reservoir oil is required for the gas to achieve miscibility with the crude oil. High water saturation and low oil saturation are detrimental to gas miscible displacement. Reservoirs with oil saturation below residual oil saturation are not suitable for the application of gas EOR methods.

As with all EOR processes, a knowledge of the reservoir characteristic is essential to economic success. Field tests of CO_2 floods have shown that reservoir heterogeneities such as fractures, strata discontinuities, and pinchouts can significantly reduce the effectiveness of the gas EOR process (refer to Appendix B of this report).

In addition to the above-mentioned screening factors (gas source, MMP, oil saturation, formation heterogeneity), process design factors such as injection sequence, slug size, mobility control technique, gas separation, corrosion in CO_2 injection, and solid (asphaltene, wax) deposition must be considered. Ignoring these factors may make a gas EOR project uneconomical.

RECENT RESEARCH IN MOBILITY CONTROL

Many mobility-control methods have been proposed and studied for gas flooding applications. Some of these methods which are currently being investigated are discussed as follows:

1. Foam

Foam has wide applications in industry. The research on foam technology has a long history. Since Bond and Holbrook (1959) and Fried (1961) suggested the use of foam to improve reservoir sweep efficiency for gas displacement processes, numerous investigators have made considerable effort in studying foam applications for both steam and miscible floods and in making fundamental investigations of foam flow in porous media. A prototype model, as illustrated in figure I-1, has been developed to describe foam flow behavior in porous media (Falls et al., 1986; Friedmann, et al., 1988). For foam flow in porous media, modifications are introduced by replacing the relative permeability and the gas viscosity in Darcy's equation with an effective relative permeability and an apparent gas-foam viscosity, respectively. Both the apparent foam viscosity and the effective gas relative permeability depend on foam quality and texture. Therefore, foam research was focused on the development of the relationships between the gas mobility and foam characteristics-foam quality and texture. Foam quality is defined as the ratio of gas volume to the total foam volume. Foam texture is a measure of the average volume or equivalent radius of its bubbles and is represented by the average number density of bubbles and lamellae. This simplified approach inherits the same problem as that of conventional reservoir simulators: i.e., multiphase flow phenomena are controlled by the relative permeability parameters. In the presence of foams, the effective relative permeabilities for gas, oil, and water are difficult to determine. No experimental method has been developed for the measurement of three-phase relative permeability for oil-gas-water systems with foam. Several experiments have been conducted to measured gas-surfactant solution relative permeability (Bernard and Holm, 1964; Friedmann and Jensen, 1986; Huh and Handy, 1989). They found that the permeability of gas was greatly reduced by foam, whereas the relative permeability of water was not affected by foam. Also, little change in gas permeability was observed over a large saturation range in the presence of foam. The presence of oil may affect foam stability. The interactions between an oil phase and foam lamellae are extremely complex (Nikolov et al., 1986). To the limit of our knowledge, there is no report in the literature about three-phase relative permeability measurements for foam systems with oil. The lack of well-defined and measurable three-phase relative permeabilities has made the foam simulators developed based on Darcy' law unpractical. The use of Darcy's law to describe foam flow behavior in porous media is still somewhat debatable.

After more than a decade of research, some research progress has been made in the science of foam, but foam technique is still not mature for gas EOR application. Because the science of foam covers so many areas, a thorough review of foam technology was not the objective of this investigation. This report only gives a brief review of progress in development of the foam technique for gas mobility control. That progress is discussed under the following subjects:

Foam Simulation

Computer simulation is an important research tool for gas mobility control and sweep improvement studies and is the only way that dimensions of laboratory experiments can be scaled up to dimensions of the field. As illustrated in figure I-1, the main part of a foam simulator is the same as that of conventional reservoir simulators. Darcy's law is still employed in mechanical balance equations with the use of apparent viscosity and effective gas relative permeability. Both these parameters were related with foam texture.

A one-dimensional foam population-balance model has been developed to quantify foam texture in terms of the number densities of moving foam (n_f) and stationary foam (n_s) (Fall et al., 1986). The number density of foam bubbles and lamellae is determined by the rates of foam generation and coalescence, which are discussed in the following sections. Chevron Research Group (Friedmann et al., 1988) has presented their simulation study of high-temperature foam displacement in a one-dimensional (1-D) model. Because of the limitation of laboratory capability, no experiment has been conducted to test foam flow in a 3-D model. Sufficient data do not exist to utilize a foam simulator for gas mobility control study and for field process design.

Foam Rheology

Studies on foam rheology have been conducted using a number of rotational viscometric devices and continuous-flow-tube viscometry. Foam is a non-Newtonian compressible fluid. Experimental results show that foam apparent viscosity increases sharply as the foam quality becomes greater than 90% and depends on shear rate. Besides foam quality, foam texture have important effects on foam rheology. Hirasaki and Lawson (1985) have recently shown that surface tension gradients play an important role in apparent viscosity of foam flowing through smooth capillaries.

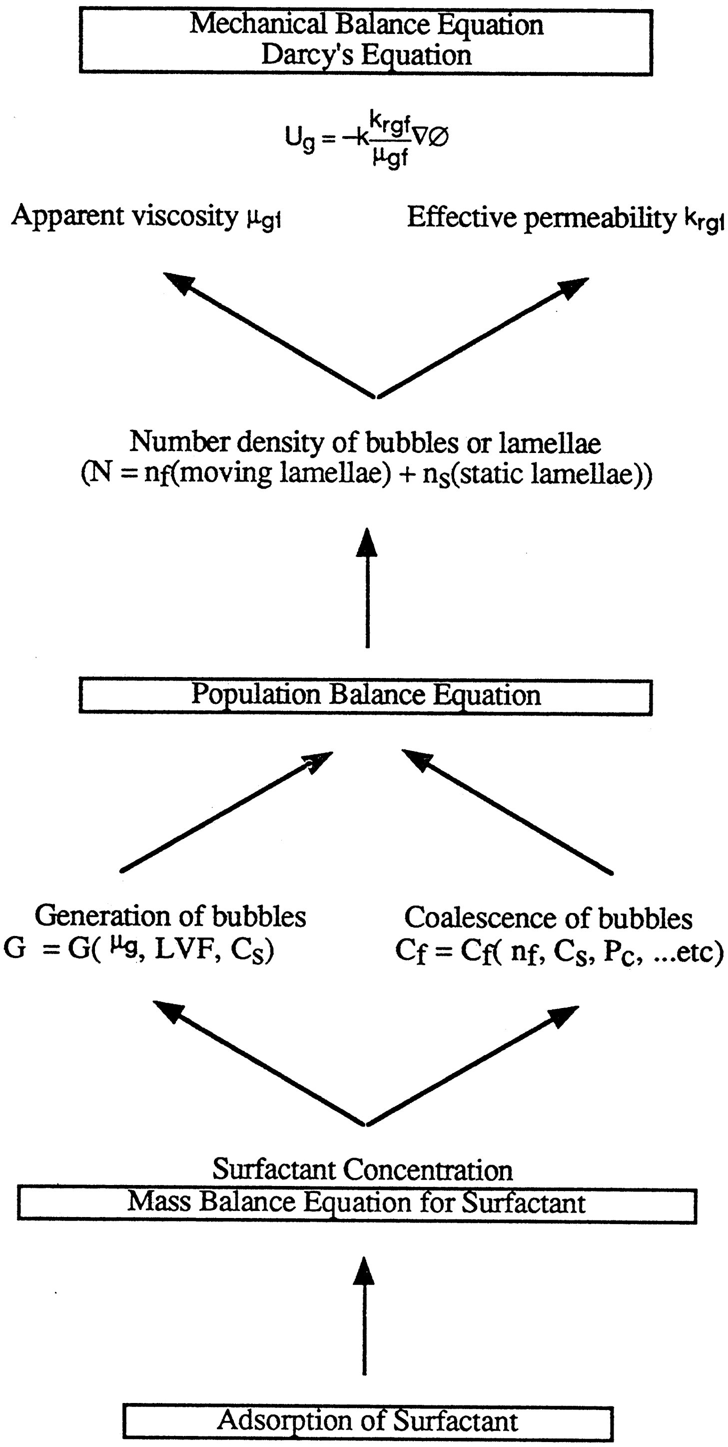

FIGURE I-1. - Outline of modeling foam flow in porous media.

A mathematical model for the prediction of the apparent viscosity of foam flowing through smooth capillaries was developed by Hirasaki and Lawson (1985). The flow of foam in smooth capillaries is one component of the flow of foam through porous media. The work of Hirasaki and Lawson was extended to account for conditions in which pore constrictions contributed to the behavior of the flow of foam (Falls et al., 1989)

Their models have been verified with their experimental results. However, these apparent viscosity models require some detailed information about foam texture and pore structure such as the number of lamellae per unit length, the radius of curvature of the gas/liquid interface, tube radius, the number of constrictions in a unit length of capillary tube, and the length of liquid slugs between bubbles, which are usually not obtainable in the case of foam flow through porous rock. Therefore, some simplified models which correlate foam apparent viscosity with obtainable parameters such as gas velocity, average pore-body diameter, average number density of flowing bubbles, and viscosities of gas and liquid were developed for the purpose of providing input for foam flow simulators (Friedmann et al., 1988; Ettinger and Radke, 1989).

Since the apparent viscosity of foam is very dependent upon geometry, the use of apparent viscosity of foam to describe its behavior in porous rock has been questioned by Heller et al. (1982). A critical and thorough review of the foam rheology literature in both theoretical and experimental studies was presented by Heller and Kuntamukkula (1987). They pointed out that the apparent viscosity measured in a capillary or rotational viscometer with "bulk foam" would not be appropriate for porous media. The concept of apparent viscosity as a measure of the resistance to the flow of foam in either pipes, capillary tubes, or porous media seems to be only qualitatively useful because of the differences in the mechanism of flow at different scales of bubble size and flow channel dimensions. Instead, they suggested that the mobility, the simple ratio between steady-state superficial velocity and pressure gradient, would be more useful and would entail fewer assumptions about the nature of the flow.

Much data on foam rheology are available in the literature. "Shear thinning" trends, "shear thickening" trends, and no effect of flow rate have all been observed under various conditions. Recently, some studies have found that foam mobility was "shear thinning" at high flow rates and "shear thickening" at low rates (Yang and Reed, 1989).

Foam Generation

Foam can be generated by injecting gas into a porous medium initially containing a surfactant solution. The primary mechanisms of foam generation observed in micromodels and glass bead packs have been identified and classified as snap-off, leave-behind, and lamellae division (Roof, 1970; Mast, 1972; Radke and Ransohoff, 1986; Falls et al., 1986). These mechanisms are thought to be general to all types of porous media. Gas flow rate, liquid volume fraction, and surfactant concentration are the major control factors for the generation of foam. Alternate water and gas (WAG) injection mode has a great impact upon foam generation and propagation: injection of large water slugs can destroy the generated foam. Optimum foam performance can be obtained by adequately adjusting the WAG ratio and injection sequence, and by using either surfactant replenishment in each cycle of a WAG flood, or by using a large foamer slug followed only by gas (Hudgins and Chung, 1990). Experiments have also shown that some other parameters such as oil saturation, pore structure, system pressure, and surfactant type will affect foam generation (Friedmann and Jensen, 1986). In general, the nonionic foaming agents produce high quality, unstable foams, while anionic foaming agents yield low quality, stable foams. The combination type of foaming agents, i.e., those that contain both nonionic and anionic compounds, produce high-quality foams with stable films (Raza, 1970).

Based on experimental observations, some simple models for the foam generation rate by snap-off have been proposed as a function of gas velocity (Falls et al., 1986; Friedmann et al., 1988; Ettinger and Radke, 1989). The foam generation rate is needed in the population balance equation, as shown in figure I-1, to determine bubble number density.

Foam Stability

Much of the literature on physical chemistry of surfaces is concerned with the stability of lamellae or films, which includes the thermodynamic stability, mechanical stability, lamellae elasticity, hydrodynamics of lamellae thinning, and kinetics of film rupture (Bikerman, 1973; Rosen, 1978; Akers, 1976; Krantz et al., 1986; Smith, 1989; Borchardt and Yen, 1989). Lamellae are thermodynamically metastable, and there are many mechanisms by which static and moving films can rupture. Drainage is considered the major mechanisms for foam bubble coalescence. The factors that influence foam stability and thin-film lifetime are governed by the dynamic surface properties in the system, such as dynamic surface tension and viscoelasticity of the surfaces (Huang et al., 1986). The stability of a single lamella depends primarily on the type or mixture of surfactants, the chemical composition of the brine, the capillary pressure, and the movement or mechanical disturbances that the lamella experiences. More detailed discussions about the stability of foams and thin films are outside of the scope of this report.

In EOR applications, the effect of oil on foam stability is specifically of interest. The interactions between an oil phase and foam lamellae are extremely complex. Nikolov et al, (1986) pointed out that foam destabilization in the presence of oil may not be a simple matter of oil droplets spreading upon foam film surfaces. The pseudoemulsion film tension, the droplet size and number of droplets may all contribute to destabilizing or stabilizing the three phase foam structure. The deleterious effects of oil on foam have been observed by many; sometimes oil recovery is impaired (Yang and Reed, 1989). Thus, the rate of foam coalescence is difficult to estimate. Some models to describe foam coalescence rate have been proposed and used in foam simulators (Friedmann et al., 1988; Jimenez and Radke, 1989; Yang and Reed, 1989).

Surfactant Adsorption

Surfactant concentration is the major controlling parameter for foam generation and coalescence. When surfactant solution is flowing in a reservoir formation, surfactants will be diluted by flow dispersion, retained in dead-end pores, adsorbed on rock surfaces, partitioned in the oil phase, or precipitated due to interaction with solution ions or fine particles. All these physical and chemical aspects complicate the problem of foam formation and propagation. The loss of surfactant will be detrimental to the performance of gas foam. Surfactant adsorption and precipitation are complicated problems which relate with rock surface properties, solution properties, and surfactant properties. Seldom have studies been conducted on the adsorption of commercial foaming surfactants on reservoir rocks at flowing conditions. Surfactant loss due to adsorption and precipitation in reservoir formations is difficult to predict, especially for foam. Several mathematical models used to describe the transport and dynamic adsorption of surfactants in porous media have been developed to be incorporated into foam flow simulators to predict local surfactant concentration. These models have taken into account the convection, dispersion, capacitance, and adsorption effects on concentrations of surfactants (Chung, 1991).

Because of the importance of surfactant adsorption in chemical EOR, extensive basic research on the adsorption of surfactants used for chemical EOR has been conducted under support of the U.S. Department of Energy. Some studies have been focused on the development of methods to reduce surfactant adsorption (French and Burchfield, 1990; Falls, 1989). The effects of pH, alkalinity, salinity, alcohol, and temperature on surfactant adsorption have been investigated. Investigations have been conducted for pure surfactants and mixed surfactants with pure minerals and reservoir sands. Much data on surfactant adsorption isotherms are available in DOE published reports.

Although a considerable number of technical papers have been published on studies of foam behavior in porous media and applications in EOR, most of them have covered only phenomenological descriptions of foam behavior in laboratory coreflood tests or in micromodels. It is impossible to review all the publications on foam technology in this report.

2. Gas Viscosifiers

Another approach taken to mitigate gas mobility problems was to increase gas viscosity by adding gas-soluble chemicals. Many methods such as the direct thickener method developed by New Mexico Petroleum Recovery Research Center and the entrainer method developed by NIPER have been proposed (see chapter 12, this report). Conceptually, the viscosifier method is the same as that of using water-soluble polymers to improve waterflooding sweep efficiency. However, viscosifiers for CO_2 have been difficult to find and even more difficult for N_2 and HC . Naturally, the solubilities of large molecules such as polymers in gas are limited. Although the solubility can be enhanced by supercritical extraction, the resulting solubility is still too low to have a significant improvement on gas mobility.

According to recent research reports, New Mexico Petroleum Recovery Research Center has successfully synthesized a number of ionomers (silicon-containing triorganotin fluorides), which are relatively short chain polymers that contain controlled numbers of ionic groups in each molecular unit. The solubility of these ionomers is still undergoing laboratory tests. On the other hand, Chevron Research Group (Bae and Irani, 1990) has found that commercially available polysiloxanes are effective viscosifying agents for CO_2 when used in combination with cosolvents. The viscosity of CO_2 was increased by two orders of magnitude.

The problems of finding light hydrocarbon solvents as viscosifiers appear somewhat less difficult, but the increase in viscosity is not significant. The concept of employing entrainers to increase the solubility of polymer in CO_2 has been proposed (Cullick, 1986). The idea of the entrainer method is to use CO_2-soluble solvents (e.g., iso-octane) to enhance the solubility of high-molecular-weight compounds in CO_2. Thus, the viscosity of CO_2 can be increased directly and indirectly by entrainers (Llave et al., 1988).

Besides the low solubility problem, all the viscosifier methods face several practical problems in reservoir applications. Among these problems are: chromatographic separation due to the difference in adsorption and diffusion rate; loss of the viscosifier due to adsorption, precipitation, and partitioning into oil or water phases; and injectivity loss due to polymer plugging. High costs of viscosifiers or entrainers are also a factor of concern. These problems are vital to the success of the viscosifier method. Other ideas such as in situ polymerization of monomers (ethylene, octene, etc.) in supercritical CO_2 are less likely to be successful in applications to viscosify CO_2.

3. Channel Block

Gas flow in reservoir formations is very sensitive to formation heterogeneity. The existence of fractures, microscopic or macroscopic, will create gas channeling and significantly reduce gas sweep efficiency. Several methods: polymer gelation (Seright et al., 1990), emulsion blocking, and microbial plugging have been proposed to block formation channels. Crosslinked polymer treatments to control the severe CO_2 channeling have been successfully tested in the field (refer to Part II of this report). A process for the selective gelation of a polymer for profile control during CO_2 flooding has been patented by Mobil Oil Corp. (Shu and Sampath, 1990). In this process, a size selective gel is first formed ex situ. Upon entering a thief zone or a more permeable low pH zone resultant from CO_2 flooding, the gel forms a solid, firm gel. Because of the difficulty to build a physical model to simulate reservoir heterogeneity, it is difficult to test the effectiveness of these methods for gas sweep improvement in the laboratory. There are many practical problems for the application of these methods in the field. For example, the polymer gel may trap residual oil and block oil flow; it may also block the way for gas to contact oil,.and it may impair oil production. The major challenge to the development of this technique is controlling the blocking process to minimize adverse effects.

4. Horizontal Wells

Recently, progress in nonconventional drilling techniques—including horizontal and high-angle wells and sidetracks or doglegs from vertical wellbores—has had a great impact on oil production. Evidence reveals that proper applications of horizontal drilling can result in increased oil recovery and higher production rates in some reservoirs. Costs have declined rapidly with experience and improvements in drilling and completion techniques. Today, horizontal wells appear to be more universally appropriate for naturally fractured formations, but successful horizontal completions are also being reported in thin or layered sandstones, in unconsolidated sands, and in unfractured low-permeability chalks (Stagg, 1991). Horizontal wells can be implemented to improve gas sweep efficiency. Some studies have already been conducted on applications of horizontal wells or slanted wells for sweep efficiency improvement in miscible floods (Chen and Olynyk, 1985; Adamache et al., 1990). As more companies become interested in horizontal well drilling, studies on how to utilize horizontal wells in gas EOR and how to choose pattern size and shape for regular arrays of horizontal wells will be urgently needed.

Conclusions

In gas mobility control development, the state of the art is as follows:

1. Foams for gas mobility control have been successfully tested in laboratories, but no successful field test has been reported. There have been advances in producing stable, effective

foams, but the application of foam in gas EOR is still not promising, primarily because many phenomena are not quantitatively describable.

2. Materials have been developed to thicken gases. They are not cost-effective yet, but progress is being made.

3. Plugging agents can be used to block high-permeability zones.

4. Horizontal wells improve sweep efficiency and may offer the most immediate benefit to gas sweep improvement.

After more than a decade of research on mobility-control problems, there is still no promising method that is applicable commercially. The major factor is that reservoir characteristics and multiphase flow in porous media are difficult to describe accurately. Thus, many mobility-control techniques such as foam developed in the laboratory fail in field tests (Kuehne et al., 1988). A better knowledge of reservoir characterization and multiphase flow would be very valuable for gas mobility technique development.

RECENT RESEARCH IN IMPROVING PREDICTABILITY

The causes of uncertainty of gas displacement performance predictions are: (1) inadequate representation of fluid phase behavior and some mechanisms such as viscous fingering, physical dispersion, dispersion/phase behavior, and crossflow/phase behavior interactions; (2) insufficient rock property data and insufficient description of the spatial distribution of rock heterogeneity; and (3) errors associated with numerical methods and cell size such as numerical dispersion and grid-orientation errors. Some of the problems are discussed as follows:

1. Phase Behavior

Gas EOR methods are commonly characterized by miscible or immiscible features which are determined by the phase behavior of the displacing gas and the reservoir oil. Theoretically, if the displacing gas can achieve miscibility with the oil, the gas will displace the oil completely because there is no capillary force to hold the oil in the porous medium. Laboratory experiments have shown that oil recovery efficiency can be as high as 100% under favorable miscible conditions. Therefore, early gas EOR investigations were focused on miscible displacement mechanisms studies such as phase behavior studies and minimum miscibility pressure (MMP) determinations (SPE Reprint Series No. 15 and 18).

Several correlations have been developed for MMP estimations for CO_2, N_2, and lean gas (Alston et al., 1985; Sebastian et al., 1985; Glaso, 1985; Firoozabadi and Aziz, 1986; Hudgins et al., 1990). The miscibility mechanisms for CO_2 have been thoroughly investigated in slim-tube and core displacement experiments associated with phase behavior studies (Stalkup, 1983; Yellig and Metcalfe, 1980; Holm and Josendal, 1974). The research efforts on nitrogen and hydrocarbon gases have been relatively limited.

Phase behavior for injection gas and reservoir oil plays an important role in miscible displacement. Currently available prediction techniques using equations of state are still suffering from some shortcomings. First, the generalized cubic-type equations of state (EOS), such as Peng-Robinson (PR) EOS, Redlich-Kwong (RK) EOS, and Soave-Redlich-Kwong (SRK) EOS, are not accurate for systems containing CO_2 or water, especially in supercritical and high pressure regions. Although some accurate PVT correlations are available for some substances, they are either too complicated or not generalized. In simulation, engineers still prefer the cubic type EOS because of its simplicity. Second, characterization for crude oil heavy fractions (C_7^+ fractions) is still an art, although several techniques have been presented for the C_7^+ fraction characterization (Whitson, 1983; Chorn and Mansoori, 1989). Characterizations of asphaltene and resin, which are essential for asphaltene precipitation prediction, are extremely difficult because the properties of asphaltene and resins are still not well known.

2. Incomplete Mixing

Another problem is the nonequilibrium feature of injection gas and oil in porous media. In reservoir simulations, it usually has been assumed that injected gas and reservoir oil within a numerical grid block are completely mixed and that thermodynamic equilibrium criteria are achieved within a numerical time step. These assumptions are acceptable for the gas displacement process in one-dimensional (1-D) models, such as slim-tube and linear core, but are unrealistic for actual field gas flooding.

The complete mixing assumption has been tested with experimental results in a 3-D physical model (Ammer et al., 1991). Simulations overpredicted the recovery rate and the ultimate recovery of oil with the assumptions of complete mixing and thermodynamic equilibrium, even for such a small (24.25-in. x 9.75-in. x 3.25-in.) and homogeneous physical model.

Micromodel experiments have shown that injected CO_2 gas contacts only a small portion of waterflooded oil (Orr and Taber, 1981). Most of the residual oil is encompassed by water phase and is discontinuous. Injection gas may have to diffuse through the blocked water phase before mixing with trapped oil, which is a slow process. Thus, the injection gas cannot completely mix with the reservoir oil, and the miscibility developed through the multiple contact process may not be achievable at reservoir conditions as it is in laboratory experiments.

Molecular diffusion plays an important role in a gas displacement EOR process at reservoir conditions. A compositional and incomplete mixing simulator that empirically accounts for the macroscopic effects of viscous fingering by assuming incomplete mixing within grid blocks has been proposed (Nghiem et al., 1989). In this method, an additional parameter is required to define the rate of mass transfer of oil from the 'bypassed' phase of grid block into the oil phase where mixing with the CO_2 is allowed to occur. Nevertheless, the overprediction of oil production resulting from the poor phase behavior description is too large to be compensated by adjusting the additional parameter.

Further research is needed to study the distributions of residual oil saturation (ROS) and water in reservoir formations after waterflooding and the diffusion process of injection gases at reservoir conditions.

3. Reservoir Description

Gas flow in reservoir formations is dominated by permeability variations. Finger patterns and even gas override can be modified by the permeability distribution if the permeability is sufficiently variable (Araktingi and Orr, 1990). Accurate information for permeability distribution, fracture configuration, and the location of faults is critical to gas EOR process design. Mobility control method design relies on these geological data. Reservoir characterization is the foundation for all EOR methods.

4. Simulation Techniques

Although many compositional simulators have been developed, these simulators still have many shortcomings. As mentioned in above sections, the assumption of complete mixing and phase equilibrium in compositional simulators is unrealistic. The gas diffusion process and the large volume increase in oil after mixing with CO_2 still cannot be taken into account in simulations. These two mechanisms are very important for fractured reservoirs. So far, reservoir simulators for fractured reservoirs are not sophisticated, especially for gas EOR . Other problems such as numerical dispersion and time-consuming computation remain to be solved.

SUMMARY

According to the reported results of miscible carbon dioxide EOR field tests, incremental recoveries by CO_2 miscible floods have ranged from 7 to 22% of original oil in place (OOIP) (Appendix B, this report). These results show that the observed miscible phenomena and the high oil recoveries achieved in the laboratory have not been attained in the field. In field applications, oil recovery efficiency is dominated by the sweep efficiency. Widespread application of gas

flooding is hindered by poor mobility control and uncertainty in predicting recovery efficiency in field projects. Although research efforts have been concentrated on these two problems and some progresses have been achieved, the problems are still intractable. Part of the reason is the limitation of laboratory-scale methods for mobility control research. Results from a 1-D coreflood test cannot be applied to a 3-D model; success in laboratory tests should not be expected in the field. Reservoir simulators are not sophisticated enough to be used for sweep efficiency tests because they are still unable to describe multiphase flow in reservoir formations accurately. Thus, even though many ideas have been proposed or patented, none of these has been proved in field tests. Industry and the Department of Energy have to be aware that the two problems are very complicated and should not expect an easy and quick solution. It will require long-term research, and more effort must be given to fundamental studies.

As being recognized by the DOE's new Advanced Oil Recovery Program Implementation Plan, the application of CO_2 and HC gas will be fundamentally crucial in mid-term time periods for recovering much of the oil in high-priority geological classes. Gas EOR research is now at a turning point. A clear long-term policy and correct direction are needed for the design of a more efficient research program. As pointed out in this review, most of the mobility-control methods deserve further research. Technologies in reservoir characterization and in multiphase flow description are vital to gas mobility control and prediction technique developments. In the near term, horizontal wells may be the only means to improve gas sweep efficiency. Studies on how to utilize horizontal wells in gas EOR will be urgently needed as more companies become interested in horizontal well drilling. In the next section, areas where research is needed are outlined.

Research Needs

Based on the above review, the areas in which further research is needed are identified and classified as near-term, mid-term, and long-term studies as follows:

Near-Term

(1) Development of improved methods to predict phase behavior.

This includes the improvement of equations of state and C_7^+ fraction characterization techniques and the study of phase behavior in porous media. Equation of state study is still very active in academic research. In EOR applications, research has to focus on CO_2-oil and CO_2-brine systems for gas EOR and H_2O-oil systems for steamfloods. More experimental data are needed to model these systems. Modification of currently used equations of state such as RK, SRK, and PR EOS is a near-term research priority. In technique development for the C_7^+ fraction characterization, more data on thermophysical properties and chemical composition analysis for heavy fractions are needed. For the characterization of asphaltenes, advanced techniques have to be developed to measure the properties (e.g., molecular weight, particle size) of resins and asphaltenes in crude oil.

(2) Development of a channel-block method for profile modification.

A 3-D physical model needs to be designed for the channel-block method. Improvement of currently available gel polymer simulators such as NIPER's permeability modification simulator, which can be achieved in the near-term, will be very useful for this research. This research should be coordinated with chemical polymer EOR research with emphasis on gas flow control in heterogeneous porous media.

(3) Development of improved prediction techniques for asphaltene precipitation.

There has been great progress in the development of predictive methods for asphaltene precipitation. In all the predictive models, characterization of asphaltene fractions is still a problem because its chemical structure and properties are not well known. More experimental data are needed to test all the developed models. Development of methods to avoid asphaltene precipitation problems is needed.

(4) Application of horizontal well technologies to gas EOR.

The following subjects need to be studied: fluid flow profile and gas sweep with horizontal wells as gas injection or production wells, pattern size and shape selection, proper placement of horizontal wells for gas EOR application, effects of multiphase flow in horizontal wells on oil production, horizontal well simulator development, and optimum process design.

Mid-Term

(1) Investigation of the effects of different scales of heterogeneity on recovery.

The mechanisms for CO_2 miscible or immiscible displacement in homogeneous porous media are well studied. In heterogeneous or fractured formations, the controlling displacement mechanisms are different. The soak period is an important process design parameter which will determine recovery efficiency because molecular diffusion plays the major role in heterogeneous formations. A correlation between the optimum CO_2 soak period and the scale of heterogeneity needs to be developed.

(2) Investigation of the effect of incomplete mixing and phase behavior in porous media on recovery efficiency.

Knowledge of the combined effects of gravity segregation, viscous fingering, channeling, and reservoir heterogeneity on phase behavior are important to the improvement of prediction techniques. Oil and water distribution in reservoirs after secondary recovery is also an important factor which will affect the gas-oil phase behavior. An adequate description of these effects on phase behavior and fluid in porous media needs to be developed and employed in compositional model simulators.

(3) Development of improved compositional simulator for gas flooding.

In addition to those problems associated with numerical methods such as finite difference approximation, numerical dispersion, and grid orientation, gas EOR simulators need to be able to overcome those problems discussed in the above sections. Some of the phenomena which are difficult to describe in a compositional simulator are : multiphase (at least three phases) flow, highly compressible properties of supercritical fluid, and dissolution of gas in reservoir fluids.

Long-Term

(1) Development of novel methods for gas mobility control.

Research on the gas mobility control problem should be continued until it is solved. Besides those methods mentioned in this chapter, researchers need to look for other new ideas. Methods of using gas viscosifiers or thickeners deserve further studies to find a cost-effective agent. But, in the development of gas thickener techniques, factors such as adsorption, precipitation, and partitioning need to be taken into account.

(2) Investigation of the fundamental properties of foam.

Research needs to focus on quantitative study of foam flow behavior in porous media. Special experimental tools need to be developed for measurements of foam flow properties in porous media. The dependent variables and characterization parameters for the behavior of foam flow in porous media need to be identified and quantified. Also, the applicability of Darcy's law for foam flow in porous media needs to be critically reviewed. If Darcy's law is still applicable, a clearer definition and a standard measuring procedure need to be developed for the two flow-control parameters: the apparent viscosity and the effective relative permeability. Then, the relationships between these flow parameters and those identified foam characterization parameters can be constructed. A thorough review of foam techniques for gas mobility control is needed for DOE and industry to make decisions on the continuity of this research and the direction for future research.

(3) Study the characteristics of multiphase flow in porous media.

Gas flooding encompasses at least three phases - gas, oil, and water flowing in reservoir formations. To describe three-phase flow is very difficult because of the complicated interactions among the three phases. The relative permeability of each phase is dependent not only on the saturation of the other two phases, but also on their distribution. The injection gas can dissolve into oil and water phases. Mass transfer between CO_2 gas and reservoir oil can cause a large volume change in the oil phase. All of these problems make the determination of three-phase relative permeability intractable. The validity of Darcy's equation to describe multiphase flow in gas flooding is questionable. More rigorous equations need to be developed. Furthermore, the problem of multiphase flow in fractured reservoirs is a big challenge to researchers and needs more studies.

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CHAPTER 3
SURFACTANT FLOODING: STATE OF THE ART REVIEW

By P. B. Lorenz

INTRODUCTION

Surfactant enhanced oil recovery enjoyed its heyday during the period of high oil prices. Many advances resulted from laboratory work, theory, computational procedures, and improved engineering. The several reviews of the state of the art that have appeared within the past decade (Mattax et al., 1983; National Petroleum Council, 1984; Kessell, 1987; Nelson, 1989; Thomas and Farouq-Ali, 1989) have indicated the new directions in which the technology is going. Progress in these directions is noted below.

The current pattern of application — limited more by economics than by technology — is seen in reports on field projects (Combe et al., 1990; Moritis, 1990) and chemicals being marketed (*Petroleum Engineer International*, 1990). Six current field projects are reported for the United States: one success, four promising, and one too early to tell. A new project by ARCO in Newton County, Texas, and one by Marathon in Pecos County, Texas, were scheduled for startup at the end of 1989. The ARCO project has been cancelled along with the chemical flooding group. Three projects were recently terminated: the Texaco Salem project was promising, but the other two were discouraging. Overseas, the Bothamsall project in England (a pilot for the North Sea) is still active, but discouraging. Few results from the Hankensbuettel project in Germany were reported, but it appears to have recovered significant oil. The terminated Chateaurenard project in France was a success. There is no information about the Total project in Handil, Indonesia.

In the United States, the majority of the field projects on surfactant flooding were performed in deltaic reservoirs; eight of the 10 field projects reviewed in part II were from reservoirs that can be identified as deposited in a deltaic environment. In an analysis of 20 field projects that were conducted in deltaic reservoirs (DOE, 1991a), channeling, compartmentalization, directional permeability trends, formation parting, and formation salinity are the heterogeneities commonly observed in these field tests that contributed to the lower than expected oil recovery. More significantly, in the same study (DOE, 1991b), it was found that the recovery efficiency declined from 60 to 70% to less than 30% for type of well spacings of greater than 1 acre. Such behavior is attributable to compartmentalization, a reservoir heterogeneity that is known to be present in fluvial dominated deltaic reservoirs.

EOR surfactants are marketed by Exxon Chemical, Shell, BP Chemicals, and Stepan (*Petroleum Engineer International*, 1990). Eleven patents were issued in 1990 for new surfactant products.

The primary need is for continued improvements in reservoir evaluation and remedial procedures. The horizontal well technique is capable of reducing many limitations imposed by reservoir structure. This review is directed only toward the process of oil mobilization by surfactants.

MAJOR FRONTIERS OF IMPROVING TECHNOLOGY

Salinity and Temperature Tolerance

The need for surfactants that can function at high temperature and high salinity has been emphasized repeatedly (Mattax et al., 1983; National Petroleum Council, 1984; Kessell, 1987). Table I-2 shows that a high proportion of the well-documented field tests (Lowry et al., 1986; Lorenz, 1989) have been carried out near the upper limits of 200° F and 100,000 ppm, proposed by the National Petroleum Council study (1984). Figure I-2 shows that there are many reservoirs, otherwise amenable to surfactant flooding, outside the established salinity and temperature limits. Field tests have been performed beyond these limits (Holstein, 1982) but the results are less completely reported. The simple parameter of salinity also disguises the additional demands that hardness makes on surfactant design. The NPC screening criterion that excludes carbonate reservoirs and those containing gypsum or anhydrite needs to be relaxed because of the development of hardness-tolerant surfactants. Attempts to invent a NaCl-equivalence for hardness have not been very successful (Hedges, 1984; Puerto and Reed, 1985).

Actually, NPC's salinity limit was selected because of a lack of field experience at higher salinities. Preflushes have fallen into disfavor (Mattax et al., 1983; Salter, 1986) as being inadequate. Even if sweep efficiency were 100% and ion-exchange equilibrium were complete, the surfactant itself is a potent ion exchanger and would be degraded by equilibrium-residual divalent cations. For the eight field tests most recently reported (Lowry et al., 1986; Lorenz, 1989; Holley and Cayias, 1990) surfactant was injected directly after waterflood in five cases. The surfactant in the McClesky test (Holley and Cayias, 1990) was designed to be tolerant of at least a fourfold variation in salinity. The surfactant for the very successful third Loudon test (Maerker and Gale, 1990) was matched to the high connate salinity and hardness of the reservoir.

With regard to selection of surfactants for high-salinity regimes, the following trends have been noticed:

Optimal salinity increases with ethylene oxide number for alkyl-aryl ethoxylated sulfonates but not for alkyl ethoxylated sulfonates (Skauge and Palmgren, 1989). Optimal salinity decreases with an increase in the hydrophobe chain length (Puerto and Reed, 1985) and a benzene ring is equivalent to about 4 methylenes (Skauge and Palmgren, 1989). Unsaturated species, i.e. alpha- or internal-olefin sulfonates, have high optimal salinities (Salter, 1986).

TABLE I-2. - Selected parameters for surfactant field tests[1]

Pilot name	Tertiary recovery, % ROIP	Oil content of injected slug,[2] %	Temperature, °F	Salinity, ppm of TDS
Delaware Childers	0	0	86	10,400
El Dorado Chesney	3.4	0	69	86,830
Bradford Lawry	5.3	18	64	2,950
El Dorado Hegberg	6.3	67	69	86,830
Jones City	8.4	60-70	95	85,000
Manvel	12	0	165	107,000
West Burkburnett	13	0	85	150,000
Bell Creek Pilot	14	61	110	7,400
Loudon I (1972)	15	0	80	104,600
Salem I (Mobil)	17	0	72	120,000
North Burbank	19	0	120	87,100
Borregos	20	0	165	33,000
Big Muddy demo	22	0	115	7,800
Sloss	22	0	200	2,500
Benton Pilot	24	0	85	110,000
Wilmington	25	22.5	145	81,000
Bell Creek expansion	28	(ca. 60.)	110	7,400
Glenpool	29	0	95	81,000
Robinson M-1	31	7.6	72	16,000±
Robinson 219R	32	15±	72	16,000±
Chateaurenard Industrial	34	15	86	400
Big Muddy Pilot	36	0	115	7,800
Bradford Bingham expansion	37	47	37	2,950
Robinson 119R	38	?	72	16,000±
Bradford Bingham	39	39	68	2,950
Chateaurenard Pilot	42	40	86	470
Salem II (Texaco)	47	0	72	120,000
Loudon II (1983)	60	4	78	104,600
Robinson Henry W	63	(ca 60)	72	16,000±
Loudon III (1990)	68	?	78	104,600

[1] From Lowry et al., 1986, and Lorenz, 1989.
[2] In many cases, the surfactant contained an unreported amount of unreacted oil. Numbers in this column smaller than 10 are reported unreacted oil.

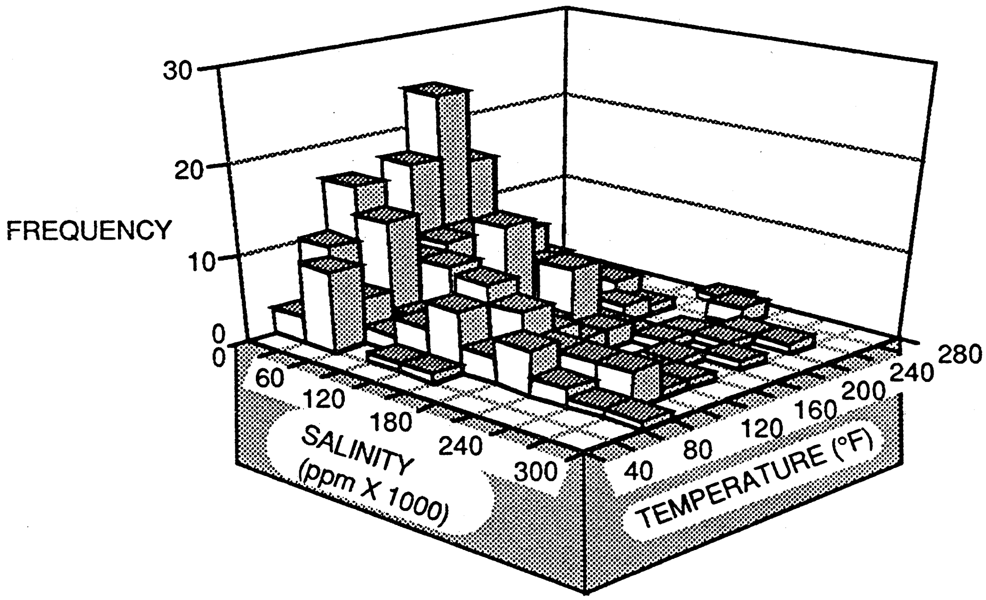

FIGURE I-2. - Three-dimensional bar graph for temperature with salinity of the restricted datafile from the DOE reservoir database (Strycker, 1989).

There appears to be a slower rate of advance in high-temperature surfactants. With the variety of structures now known, it is possible to design alcohol-free surfactant systems that are effective throughout the temperature-salinity ranges of figure I-2, but many are excluded by cost considerations. The "classical" alkly-aryl sulfonates are effective and thermally stable over a wide range of temperatures at low salinity, but in the absence of alcohol are limited by the formation of condensed phases and persistent emulsions. Ethoxylated and propoxylated sulfates are practical over a wide range of salinities, but are restricted to temperatures below 50° C by the tendency to hydrolyze (Mattax et al., 1983). Ethoxylated sulfonates are stable at high temperature and high salinity, but are expensive.

In addition to tolerance for high temperature and salinity, there is a need for surfactants that have a tolerance for a wide variation of salinity, so that they will not be degraded, for example by encountering pockets of high salinity brines left over from waterflooding. There does not seem to be a systematic way of designing surfactants that are effective over a range of temperatures and salinities. On the basis of published information, this has been a matter of luck rather than design. One well-known problem is the inverse relation between solubilization and width of the salinity window. But this applies strictly within a homologous series, and it is possible to increase both solubilization and window width by structure changes (e.g., branching) or using mixtures (Llave et al., 1990).

Improving Surfactant Effectiveness

A great deal of the literature has been concerned more with defining optimal conditions than with inquiring how well a surfactant at optimal conditions reduces interfacial tension and cosolubilizes oil and water. Moreover, since much of the previous work on surfactants involved blends with alcohol, the relation between structure and surfactant activity is a relatively new science. Recent surveys of the experimental trends by Salter (1986) and Skauge and Palgren (1989) have addressed the questions in the proper order: For a given oil, brine, and temperature, what structure is required for a surfactant that

(a) has maximum surface activity;

(b) has acceptable solubility in brine and least tendency to form gels and liquid crystals;

(c) has a minimum tendency to be adsorbed?

Since mixtures are necessary for adjustment to optimum (Puerto and Reed, 1985), and appear to exhibit synergism (Maini and Batycki, 1985), we should not expect to find a single species; but the trends, supported in a general way by theory (Robbins and Bock, 1988), are as follows:

(a) Surface activity is increased by increasing molecular weight while maintaining hydrophilic-lyophilic balance (HLB). With ethoxylates, longer chains at both ends of the amphiphilic molecule increase cosolubilization by making it harder for the interface to be curved. Very approximately, the addition of one ethylene oxide group is balanced by the addition of one methylene group (Skauge and Palmgren, 1989). Cosolubilization is larger for more linear molecules; that is, there is a tendency for solubilization to be reduced by branching, and this includes aromatization. The methylene equivalent of a benzene ring is 2 - 3. The order of effectiveness of hydrophilic groups is: sulfonates are similar to sulfates and superior to carboxylates.

(b) Brine solubility is improved by ethoxy groups. A polyethoxylated molecule that is too water soluble to be a good surfactant can serve as a cosurfactant. A distribution of ethylene oxide number improves water solubility (Lelanne-Cassou et al., 1983; Olsen and Josephson, 1987), and an aromatic ring or branching of the hydrophobe reduces solubility of ethoxylated surfactants (Skauge and Palmgren, 1989). Sulfates are more soluble than sulfonates.

(c) Adsorption of nonionic surfactants is smaller, the farther from the cloud point temperature (Verkruyse and Salter, 1985). This suggests that the trends on structure for adsorption would be similar to those for solubility.

Many new surfactant types have been investigated and patented, such as carboxylates, phosphates, amines, nitriles, exotic sulfonates, and molecules that incorporate two of these functional groups. For the most part, their use is deterred by cost. It is beyond the scope of this review to evaluate these materials; however, such an evaluation could have value as a guide to promising lines of research.

Slug Integrity

In review of recent field projects, it was concluded that (Part II, this report) some inherent weaknesses in surfactant flooding are limiting the application of this process. Degradation of slug integrity as it propagates through the reservoir is one of the impediments. Improvements have been made in four ways.

Elimination of Alcohol

Elimination of alcohol requires surfactants that are water soluble but still effective. The majority of the advances have been in developing ethoxylates and propoxylates (Olsen and Josephson, 1987; Skauge and Palmgren, 1989; Maerker and Gale, 1990). Sulfonates with mid-chain attachments (Lelanne-Cassou et al., 1983) and internal olefin sulfonates (Selliah and Wade 1985) have shown some promise. Amphoterics, such as amine oxides (Olsen, 1989), also have favorable characteristics. For tailoring surfactants to reservoir conditions in the absence of alcohol, it is necessary to use blends of surfactants (Maini and Batycki 1980; Puerto and Reed 1985; Roefs, 1989; Llave et al., 1990). Sulfonates and alcohols, with very different oil/water affinities, tend to go by different paths in a reservoir, but chemically similar surfactants with HLB values differing by as much as 5 units have been reported by some authors to copartition (Wade and Schechter, 1980) and coadsorb (Balzer, 1983). Other authors indicate that even commercial ethoxylates with a distribution of ethylene oxide numbers fractionate by partitioning (Graciaa et al., 1983). Fractionation is minimized if all components are well above their critical micelle concentrations (CMC) (Salter, 1986). In cases for which chromatographic separation is an unavoidable result of design requirements, proprietary methods have reportedly been developed (Holley and Cayias, 1990) to hold separation within limits dictated by the distances and projected recovery times.

Alcohol has been used to adjust slug viscosity for a favorable mobility ratio. This is accomplished more reliably by adding polymers (Mattax et al., 1983). The added cost is compensated by the increased effectiveness. However, it is necessary to overcome or avoid surfactant-polymer incompatibilities (Roefs, 1989; for a review, see Kalpakci et al., 1990).

Suppression of Adsorption

An increasingly popular way of doing this is to add alkali (Lorenz, 1991) in a preflush or in the slug. Another sacrificial agent is lignosulfonate, which has been used with mixed success (Thomas et al., 1986; Hong et al., 1987; Hong and Bae, 1990). Chemical gradients within the slug (discussed below) cause some of the surfactant to be desorbed.

Use of Chemical Gradients

Proposals for deliberate segregation of components to form a gradient are an extension of the well-accepted salinity gradient (Nelson, 1989). The design requirement is a leading II^+ (oil external) microemulsion and a following II^- (water external) one. This assures optimal conditions at some stage; it combats surfactant loss by phase trapping, reverses adsorption, sharpens the concentration profile, and mitigates the effect of gravity segregation (Nelson, 1989). The effect can be achieved by an alcohol gradient (Trushenski, 1984) or an HLB gradient. The latter was proposed by Minssieux (1987) for a reservoir too saline for an effective salinity gradient. He combined a sulfonate with nonionics graded from HLB 11.6 to 15.5. Incidentally, Maini and Batycki (1980) (who did not work with gradients) found that optimization was easier using a sulfonate with two cosurfactants having a still wider range of HLB. Chou and Shah (1981) took a different approach, selecting surfactants that gave a reverse HLB gradient, to moderate the adverse effects of an excessively steep salinity gradient.

Gradients have been used in other ways. Baviere et al. (1985) used a succession of surfactants to overcome problems with ion exchange. Thomas et al. (1988) found that a gradient of oil content, with oil-rich composition upstream, performed better than a single slug. As a matter of subordinate interest, table I-2 shows that among well-documented field tests, there has been no correlation between recovery and oil content of the injected microemulsion.

Polymer Propagation

A new problem in slug integrity is introduced when the mobility is adjusted by adding polymer to the surfactant. Polymer propagation is subject to constraints that are different from those of surfactant: independent adsorption behavior, mechanical entrapment, inaccessible pore volume, and, of course, virtually no oil affinity (see also Part II, this report). The mechanical entrapment is a strong function of permeability, which makes polymer propagation very sensitive to heterogeneity. A corollary effect is that polymer retention will be accentuated in regions where oil displacement is poor, and effective water permeability stays low.

When polymer and surfactant get separated, mobility control is lost. This is believed to be a significant factor in the performance of Exxon's expanded pilot test in the Loudon field (Huh et al., 1990). The polymer was transmitted only a fraction of the distance from injection to production wells. These investigators believe that it is vital to the success of the surfactant method to solve the problem of polymer propagation over long distance.

Low Concentration Surfactant

Although field (Lorenz, 1989) and laboratory (Gogarty, 1978; Murtada and Marx, 1982) experiences have shown that surfactant slugs are more effective at higher concentration, there is a persisting interest in "low tension floods" — a dilute surfactant in a larger slug. Technical effectiveness must be balanced against compatibility problems at higher concentrations, and problems with injectivity; also logistics in offshore operations.

If mobility control can be dispensed with, there will be a reduction in costs of materials and equipment. Adding surfactant to injected brine is indeed observed to cause increased production (Nelson, 1989), but so far the benefit-cost ratio is too low. It is possible that the technique can be developed to have a limited applicability to selected reservoirs, if surfactants can be developed with high displacement efficiency and low adsorption (Raterman et al., 1988), and if the process is optimized with respect to slug size and concentration.

A more promising technique is "surfactant-enhanced polymer flooding" (Chiang, 1985; Roefs, 1989), or "low-tension polymer flooding" (Kalpakci et al., 1990). For low concentration of surfactant, polymer requirements are decreased, and there is a reduction of problems with surfactant solubility, injectivity, and surfactant-polymer incompatibility. Rather large slugs have been used in laboratory investigations, 0.3 to more than 1.0 PV. The data suggest that addition of surfactant to a normally-designed polymer flood can result in marked increases in recovery. Surfactant concentration (from 0.1 to 1.5%) must be selected for particular reservoir conditions. There is a threshold of total surfactant injected below which there is no benefit at all (Enedy et al., 1982). This is associated with surfactant retention. For example, using a 0.3% surfactant solution in a reservoir with 20% porosity and 0.3 mg/g retention, calculation shows that it takes 0.35 PV to satisfy adsorption demands. Lower concentrations (below the plateau in the adsorption isotherm) will have a lower threshold and a higher process efficiency (oil-surfactant ratio) (Enedy et al., 1982) but also a longer delay and higher operating costs.

OTHER AREAS OF RESEARCH

Low Permeability and High Viscosity

Low permeability and high viscosity are listed as constraints in the National Petroleum Council report (1984). The lowest permeability in a successful field test was 50 md for the Big Muddy, WY (Ferrell et al., 1988); the Bradford-Lawry test in a 10-md reservoir was a failure, partly because of low injection and production rates (Suffridge, 1984). Research needs for low-permeability surfactant flooding are to develop surfactants of high solubility (no filtration) and effective polymers with rigid molecules (no mechanical entrapment). Surfactant can even be detrimental in a low permeability reservoir if it inhibits imbibition which has been claimed in some cases (Nelson, 1989) and denied in others (Keijzer and DeVries, 1990). Oil viscosity is an economic, rather than a technical constraint, as it requires high-viscosity displacing fluids, which leads to slow injection and production rates. The highest oil viscosity in a successful field test was Chateaurenard at 40 cP (Chapotin et al., 1984).

Scaling and Modeling

The rule-of-thumb has been that frontal advance rates in laboratory corefloods must match those in the field, and that flood tests to get data for scaling up by numerical simulation must be carried out in cores at least 1.3-m long. Some new criteria for designing scaled chemical flooding experiments have been presented by Islam and Farouq Ali (1988).

There are two facets to modeling: process simulation and reservoir modeling. Encouraging progress has been made in process simulation. The UTCHEM model (Camilleri et al., 1987), developed over the past decade and still being upgraded (DOE Progress Review 62, 1990), was applied successfully to field results from the Big Muddy pilot (Saad et al., 1989). Exxon's independently-developed simulation gave a reasonable match of performance of the pilots in the Loudon field (Huh et al., 1990). It is still a challenge to model the reservoir, limited on one hand by the data available, and on the other hand by the need to keep the number of parameters within manageable proportions (see chapter 10, this report).

Experimental Techniques

Exxon (Puerto and Reed, 1983) has developed a way of modeling crude oil that is superior to the concept of equivalent alkane carbon number. The needed data are the molar volume and the H/C ratio. This information is used to correct experimental results on alkanes to predict the behavior of (live) crude. A correction of data with NaCl to estimate the behavior with hard brines was developed empirically, but is specific to the surfactant type. The approach allows blending of surfactants to adjust the optimal salinity to the reservoir brine, but it is less precise in estimating solubilization. Incidentally, the salinity level of the curve for optimal salinity vs. molar volume of alkanes is a measure of the HLB of the surfactant.

Measurement of phase inversion temperature is not a new technique, but is being used more in the search for surfactant systems at high temperatures (Llave and Olsen, 1988).

Although significant advances have been made in surfactant flooding, the constraints to commercialization of the process are still in designing surfactant formulations that are (a) cost effective, (b) salt tolerant, and (c) temperature tolerant; and slugs such that the process maintains its effectiveness in transit through the reservoir. The primary constraint is still the high cost of surfactants. The cost of chemicals in the latest Loudon test (DOE, 1991c) was estimated to be in the range of $18-32, depending whether the surfactant was recycled, for each barrel of additional oil recovered. At this cost, surfactant flooding cannot be competitive with other processes for economic production of domestic oil at current oil price. Developing more cost-effective surfactant formulations should be the most critical research task to be completed before additional field tests are to be contemplated.

RECOMMENDATIONS

1. Improvement in evaluating reservoirs and remedial treatments of reservoir heterogeneities.

2. The balance among effectiveness, stability, and cost should be optimized for surfactant EOR in high-salinity, high-temperature reservoirs.

3. More cost/benefit optimization should be studied for low-tension polymer floods.

4. The behavior of mixed surfactants should be explored more thoroughly with respect to the following:
   (a) maintenance of slug stability;
   (b) degree of diversity required for effectiveness.

5. Development of method to overcome surfactant-polymer incompatibility.

6. A further understanding of the role of molecular structure should be developed to assist in the design of surfactants that can accommodate wider variations in salinity.

7. A comprehensive review of alternative surfactant types should be made to determine which (if any) deserve more extended testing and development of manufacturing procedures at reduced cost.

8. Various kinds of gradients (salinity, alcohol etc.) should be investigated. In particular, consideration should be given to combined gradients, as, for example, grading from an oil-rich composition with oil-soluble surfactant to a water-rich composition with water-soluble surfactant.

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CHAPTER 4
ALKALINE FLOODING: STATE OF THE ART REVIEW

By P. B. Lorenz

INTRODUCTION

For all its economic attractiveness, alkaline flooding is not being used very actively. The most recent Production Survey in the *Oil & Gas Journal* (Moritis 1990) lists nine projects: four active and five recently terminated. Two are labeled successes, one promising, three discouraging, and two too-early-to-tell. Historically in the U.S., six of 22 alkaline floods surveyed (Lorenz and Peru 1989) have been considered successful. Most used NaOH, which provides the highest ratio of alkalinity to cost. However, in many cases, rates of consumption and scale formation are unacceptably high (e.g., Dauben et al. 1987). A recently reported NaOH flood in the U.S.S.R. appears to be successful (Melnikov 1988). Sodium silicate was used in several projects to reduce reaction with SiO_2; and it has other advantages, but in the high-pH region it still reacts with clays (Thornton and Lorenz 1988). Lower pH silicate with a high SiO_2/Na_2O ratio is less reactive and retains some effectiveness. Sodium carbonate has been the alkali of choice in several recent projects (Lorenz and Peru 1989).

Alkaline agents have been used in preflush treatment for some time. This was part of the design for five of the 23 well-characterized surfactant field tests (Lowry et al. 1986; Lorenz 1989), and was suggested as an afterthought for Chateurenard (Rivenq et al. 1985).

CURRENT PERSPECTIVES

Mobility Control

The importance of mobility control has been increasingly recognized (Auerbach 1984; Ball 1985; Saleem and Faber 1986; Alam and Tiab 1987; Nelson 1989; Lorenz and Peru 1989). The use of polymers with strong alkalis introduces the problem of thermal instability, which is serious at either end of the pH scale (Yang and Treiber 1985; Dexter and Ryles 1988). Polyacrylamide is considerably more resistant to alkalinity than xanthan (Ryles 1985; Nelson 1989). Alternative polymers have been developed on a laboratory scale (Bauer and Klemmenson 1982; Dexter and Ryles 1985). Mobility control is important also in alkaline preflush. Part of the reason for the poor performance of the first Loudon surfactant pilot (Pursley et al. 1973) was that the surfactant penetrated regions that the alkaline preflush had bypassed.

Oil Acidity

Until recently, it was assumed that a high acid number for the oil was an essential criterion for alkaline flooding. However, three other factors need to be considered:

1. Acid constituents of oil are not necessarily all precursors of natural surfactants. Some low-acid oils develop as much interfacial activity with alkalis as is developed by oils that have a much higher oil content (Ball 1985; French et al. 1989).

2. Surface activity is only one of the benefits of alkaline flooding (Krumrine et al. 1982). This is especially apparent in alkali-surfactant flooding, discussed below. Therefore, alkaline flooding is worth considering for a larger number of reservoirs than was formerly thought.

3. On the other hand, acidity is often associated with low gravity (Lorenz and Peru 1989) and high viscosity (Ball 1985), so that, with increased mobility control requirements and low production rates, alkaline flooding may not be economically preferable to thermal methods.

Alkaline-Surfactant Flooding

The literature to 1988 on this subject was reviewed in a recent report (Lorenz 1988). The combination is superior to either alkali or surfactant alone in several ways:

1. For many combinations, a lower interfacial tension is achieved than with either component separately (Ball 1985; Lorenz 1988; French et al. 1989; Surkalo 1990; French and Burchfield 1990). This results in increased recovery (Taylor et al. 1989) or reduced chemical requirements.

2. The reduction of interfacial tension is achieved faster than with surfactant alone, and is longer lasting than with alkali alone (French et al. 1989).

3. The combination can sometimes be tailored to mitigate emulsion problems that occur with a single agent (Ball 1985; Peru and Lorenz 1989).

4. Surfactants raise the optimal ionic strength for surfactants generated by alkalis (Nelson et al. 1984; Surkalo 1990), which can then be used at higher and more practical concentrations.

5. Alkalis tend to reduce the retention of other EOR chemicals, although the state of the art in this respect is less advanced than is sometimes proclaimed (Lorenz 1991).

6. Surfactant enhancement allows the use of low-pH buffered alkalis, which reduces consumption and scaling (French et al. 1989; Peru 1989).

7. Inexpensive alkalis compete for divalent cations and reduce degradation of expensive surfactants. (This capability has been exploited for many years by adding alkaline "builders" to detergents.)

8. In some cases (Lorenz 1991), alkalis appear to affect the solution behavior of surfactants in a beneficial way—but this is a fairly unexplored effect.

SCREENING CRITERIA

Recent work at NIPER (Lorenz and Peru 1991) concluded that alkaline flooding should be rejected if there is as much as 1% gypsum (or anhydrite) in the reservoir rock, or as much as 1 mol % CO_2 in the fluid. Gypsum would be indicated by 1,000 ppm (or higher) sulfate in the brine. CO_2 would be suspected if in situ pH were 6 or below. In the absence of these interfering substances, a flood at moderate pH (around 10) can be considered in low-kaolinite reservoirs. For low-montmorillonite reservoirs with less than 5 meg of divalent exchange cations per kg of rock, a very low pH (around 8.5) may be effective when enhanced with surfactant. Low salinity is generally regarded as important for alkaline flooding (Castor et al. 1981). Alkali is more effective at reducing adsorption of EOR chemicals at low salinity (Lorenz 1991). However, if the mechanism of mobilization is wettability alteration, higher salinity may be an advantage (Kessell 1987). One danger in alkaline flooding that has been underemphasized is the swelling of clays with changing ionic environment, and this must be factored into the design (Labrid and Bazin 1989).

AREAS OF NEEDED RESEARCH

The background for the following recommendations has been discussed extensively in two previous reviews (Lorenz 1988; Lorenz 1991).

1. The use of an extended "salinity requirement diagram" (two- or three-dimensional concentration scans of alkali, surfactant, and salt) to maximize oil mobilization.

2. More study of specific ion effects, and development of optimal mixtures of alkalis. Design of a means to stabilize silicate solutions at high values of SiO_2/Na_2O.

3. Study of injection strategies (surfactant, alkali, polymer).

4. Investigation of the effects of alkalis on CMC, cloud point, and partitioning of surfactants; and on the mechanical entrapment of polymers.

5. Demonstrate technical feasibility of alkaline-surfactant-polymer flooding in well documented field pilot tests.

6. Special experimental requirements:

(a) Alkali-surfactant flooding will have to be designed to compromise among competing requirements for efficient mobilization, suppression of retention (surfactant and polymer) and consumption (alkali), beneficial emulsion behavior, and cost control. Optimization with respect to a single parameter would be insufficient.

(b) Working with reservoir rocks is necessary to address differences in behavior of different minerals with changing pH.

(c) Coreflood tests are even more important here than with the other processes because of the dynamic IFT's with alkali.

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CHAPTER 5
MICROBIAL ENHANCED OIL RECOVERY: STATE OF THE ART REVIEW

By Rebecca Smith Bryant

INTRODUCTION

Microbial enhanced oil recovery (MEOR) has been recognized as a potentially cost-effective method, particularly for stripper well production. Stripper wells are in need of cost-effective EOR because independent operators produce almost 50% of the total oil recovered, but may not have facilities for needed EOR research. Microbial methods for improving oil recovery are particularly well suited to be applied in today's economic climate. Adequate data exist to demonstrate both the viability and variety of options for using microbial technology for improved oil production.

Interest in applications of MEOR field technology has increased since 1982. The lower price of crude oil as well as a more general acceptance of use of biotechnological processes probably contributed to this increase. Bryant and Burchfield (1989) have recently published an overview of MEOR technology. Because of political changes in Eastern Europe and other countries, data from some MEOR field trials have now been made public by researchers from countries such as the USSR, Germany, Romania, and China. Reports from some of these field trials have been reviewed for this MEOR assessment.

Conventional EOR processes rely on alteration of capillary and viscous forces to improve oil recovery. Chemicals used for EOR include CO_2, surfactants, polymers, and alcohols. Microorganisms can produce these chemicals by fermenting inexpensive raw materials, such as molasses. Chemicals used for EOR must be compatible with the physical and chemical environments of oil reservoirs. In the use of microorganisms in situ for EOR, it is necessary to use microbial cultures that can survive and grow at the temperatures, pressures, and salinities present. For an in situ MEOR process, the microorganisms must not only survive in the reservoir environment, but also produce the chemicals that are necessary for oil mobilization. Several laboratories have published reservoir screening criteria for microbial EOR field applications, including Clark, et. al. (1981) from the University of Oklahoma, Bubela and McKay (1985) from the Baas Becking Geomicrobiological Laboratory in Australia, and Bryant and Burchfield, NIPER, 1989. NIPER has continued to maintain a data base on all available information regarding MEOR field tests in the United States and in other countries (Bryant, 1989). The data base was designed to be incorporated into the U. S. Department of Energy's EOR Project Data Base that is part of the Tertiary Oil Recovery Information System (TORIS). These publications were reviewed to determine which reservoir parameters are the most important for successful microbial EOR field tests.

POTENTIAL RESERVOIRS FOR MEOR

The U.S. DOE Reservoir Data Base (public copy) was used to screen several oil-producing states for reservoirs with original oil in place greater than 20 million bbl that satisfy the following criteria: injected and connate water salinities less than 100,000 ppm, rock permeability greater than 75 millidarcies, and a depth less than 6,800 feet which corresponds to a temperature limitation of about 75° C (Bryant, 1991). Table I-3 shows the number of reservoirs that satisfied these parameters, and a graph of the percent of reservoirs in each state that satisfied these limiting criteria, and the total, is shown in figure I-3. The cumulative reserves for these particular reservoirs is in excess of 63 billion barrels of oil. If even 10% of this was recovered by microbial technology, an additional 6 billion barrels of oil could be produced.

TABLE I-3. Number of reservoirs by state with potential for MEOR technology

State	Total no. of reservoirs	No. of reservoirs that fit the criteria	%	Reserves, bbl
OK	97	16	17	4.4×10^9
TX	461	134	29	1.6×10^{10}
LA	190	28	15	8.3×10^9
KS	39	18	46	3.8×10^9
CA	179	106	59	2.5×10^{10}
CO	40	28	70	4.4×10^8
MS	44	4	9	1.4×10^8
NM	65	3	5	1.3×10^8
WY	67	28	42	3.0×10^9
IL	46	16	35	2.0×10^9
TOTAL	1,228	381	31	6.3×10^{10}

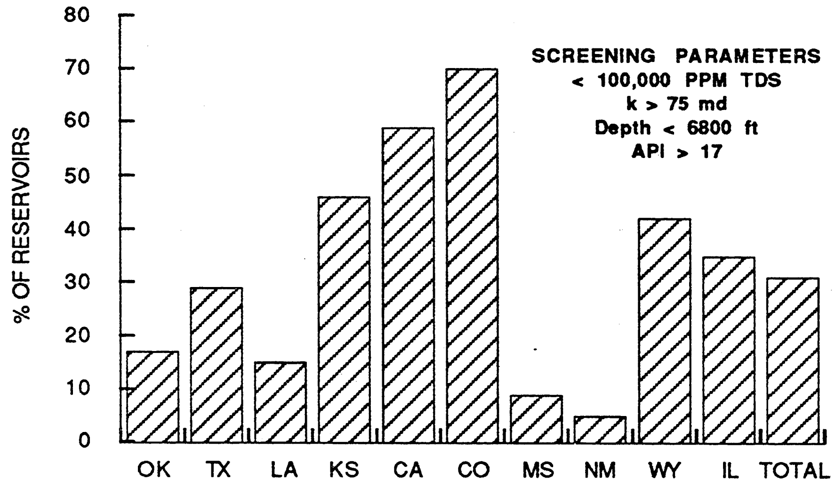

FIGURE I-3. – Graph showing percent of reservoirs in major oil-producing states that have potential for MEOR processes.

LABORATORY RESEARCH ON MECHANISMS OF MEOR

Laboratory research has demonstrated that microbial products can change chemical and physical properties (e.g. IFT, wettability, solubility) at oil-water or rock-fluid interface, selectively plug high-permeability zones to improve sweep efficiency, and increase wellhead pressure in single-well treatments. Some microbial species can also significantly improve oil production by helping to remove suspended debris and paraffins from a near-wellbore region. Table I-4 lists several microbial species used in enhanced oil recovery.

Microorganisms produce surfactants that can reduce oil-water interfacial tension (IFT) and cause emulsification. Several types of surfactants are produced by microorganisms, including such anionic surfactants as carboxylic acids (fatty acids) and certain types of lipids (Cooper and Zajic, 1980; Cooper, 1982). Optimized biosurfactant systems have been found to lower oil-water IFT to as low as 5×10^{-3} mN/m^2. In addition, biosurfactants may alter the relative permeability of rock to oil by changing the wettability of the reservoir rock and thereby increasing oil recovery (Chase et. al., 1990). Microorganisms also produce gases such as CO_2, N_2, H_2, and CH_4 that could improve oil recovery by increasing reservoir pressure and by reducing viscosity and causing

Table I-4. Microbial species used in enhanced oil recovery processes

Scientific name	Characteristics useful for EOR
Clostridium sp.	produces gases, acids, alcohols, surfactants
Bacillus sp.	produces acids, surfactants
Bacillus sp.	produces polymer
Pseudomonas sp.	produces surfactants, polymers, hydrocarbon degradation
Xanthomonas sp.	produces polymer
Leuconostoc sp.	produces polymer
Arthrobacter sp.	produces surfactants, alcohols
Corynebacterium sp.	produces surfactants
Enterobacter sp.	produces gases, acid

swelling of individual trapped droplets of crude oil. The solvents that microorganisms produce are typically low-molecular-weight alcohols and ketones. These compounds are typical of those used as cosurfactants in microemulsion formulations. Under certain conditions, alcohols and ketones could also lower surface tensions and IFTs, promote emulsification, and possibly help to stabilize microemulsions.

The transport of microorganisms in reservoir rocks has been studied in the laboratory (Jenneman et. al. 1985; Yen, 1985). Results from laboratory and field tests indicate that certain strains of microbes can be transported through reservoir rock under proper conditions. For profile modification treatments, plugging of high-permeability layers of the reservoir is desirable. Microbes that produce polymers, biomass, and slimes have been shown to reduce the permeability of cores (Raiders, 1986). One technology being proposed by Costerton et al. (1990) for microbial profile modification has been the injection of ultramicrobacteria (UMB), bacteria that under nutrient deprivation and certain environmental conditions can decrease their size presumably to penetrate further into the formation. No actual field pilots have been reported in the literature using this technology.

Development of the methodology for applying microbial technology for improving oil recovery requires an integrated laboratory and field research effort to identify and understand the mechanisms of oil recovery, to determine the relative importance of these mechanisms in oil mobilization by laboratory experimentation, to develop mathematical correlations and models to describe the physical phenomena, and to develop and apply a mathematical computer reservoir simulator to match laboratory coreflooding results and ultimately match and predict oil recovery performance in field applications. Although several attempts have been made to modify existing reservoir simulators to describe microbial processes, no model has yet fully incorporated all of the complex phenomena that are believed to be important. NIPER has developed a three-dimensional, three-phase, multiple-component numerical model to describe the microbial transport phenomena in porous media (Bryant et al., 1990c). Unfortunately, a number of the parameters required to validate the simulator are not readily available. An experimental program to provide these parameters, to test the simulator against coreflood and field tests, and to improve the various mathematical representations of physical and biological phenomena included in the simulator is in progress at NIPER.

MICROBIAL PROCESSES FOR OIL PRODUCTION PROBLEMS

Because of the diverse nature of MEOR technology, several different oil production problems have been addressed by microbial and/or nutrient injection. Some classification scheme is required to separate these different processes. To differentiate among field projects using microorganisms, they are separated according to the classification in table I-5.

TABLE I-5. A classification of different microbial reservoir treatments

MEOR process	Production problem	Type of microorganism used
Microbial well stimulation	Formation damage Low oil relative permeability	Generally surfactant, gas, acid, and alcohol producers
Microbial-enhanced waterflooding	Trapped oil due to capillary forces	Generally surfactant, gas, acid, and alcohol producers
Microbial permeability modification	Poor sweep efficiency channelling	Microorganisms that produce polymer and/or copious amounts of biomass
Microbial wellbore cleanup	Paraffin problems Scaling	Microorganisms that produce emulsifiers, surfactants, and acids
		Microorganisms that degrade hydrocarbons
Microbial polymerflooding	Unfavorable mobility ratio Low sweep efficiency	Microorganisms that produce polymer
Mitigation of coning	Water or gas coning	Microorganisms that produce polymer and/or copious amounts of biomass

The processes listed in table I-5 will be used for classification only; in some instances, no field projects using the process are being conducted, but field work has been planned based upon laboratory results.

Microbial Well Stimulation

The most practiced MEOR technique involves cyclic treatments of producing wells. These types of treatments have been conducted since 1953; however, those conducted most recently have involved some improved nutrient and microbial processes. These tests are addressed in this report.

In well stimulation treatments, improvements in oil production can result from removal of paraffinic or asphaltic deposits from a near-wellbore region or from mobilization of residual oil in the limited volume of the reservoir that is treated. Because there is a potential for improved residual oil mobilization, these treatments are distinguished from those that use microorganisms specifically for wellbore cleanup. Well stimulation treatments generally use microorganisms that require the addition of nutrient to survive and thrive for periods of several months in the well, whereas microorganisms used for wellbore cleanup are those that generally do not survive for extended periods of time and are injected on a regular basis, somewhat similar to regular injection of hot oil. The fundamental mechanisms for well stimulation are interfacial tension reduction, wettability changes, oil viscosity reduction, and repressurization due to generation of surfactant, solvent, and gases. The microbes generally do not survive outside the wellbore region without nutrient injection because they are oxygen-requiring microbes. Typically, well stimulation treatments can be implemented with only a few minor modifications to existing surface facilities, and they are relatively inexpensive.

Well stimulation treatments can be considered successful not only by improving oil production but also by decreasing the cost of maintenance and operation of a well. As an example, a microbial formulation that reduces basic sediment and water (BS&W) can improve injectivity of a well by removing damages . By improving injectivity, maintenance treatments of a well, such as hot oil or solvent treatments, may not have to be implemented as often.

During the 1950s and 1960s, countries such as Czechoslovakia, Poland, Hungary, and the USSR conducted numerous well stimulation treatments with a wide variety of microorganisms and injection protocols. For more details on these treatments, see Hitzman (1988). Underlying trends in all of these early single-well injections are that they used inexpensive sources of nutrients (usually molasses), and that they were generally successful; that is, had increases in oil production ranging from 50 to 300%. In the 1970s and 1980s, researchers at some universities and small companies in the United States conducted probably as many as 300 well stimulation treatments. Unfortunately, the information resulting from all but a few of these operations is unavailable to the public. Those for which some information is available are presented in table I-6. It is evident that many of the well stimulation treatments have been successful; however, few field tests have provided well-documented data that quantitate oil production increases and other related factors.

Microbial-Enhanced Waterflooding

For a microbial-enhanced waterflood, it is important that the microorganisms be capable of moving through the reservoir and producing chemical products to mobilize crude oil. Microorganisms can produce surfactants that can reduce oil-water interfacial tension (IFT) and cause emulsification. In addition, surfactants can alter the relative permeability of rock to oil by

TABLE I-6. Well stimulation tests in the United States and other countries from 1980 to 1990

Project conducted by	Year of test	Field/State	Reported results[1]
Oklahoma State University	1983	Oklahoma	Oil production increased
Oklahoma State University	1985	Texas	Slight increase in oil production.
Microbial Systems Corp.	1984	Oklahoma	230% increase in oil production for 7 months (0.5 to 2 bbl/day).
Fairleigh Dickinson Lab.	1986	Gailjo field Texas	Operator left.
Fairleigh Dickinson Lab.	1987	Wildcat field Texas	Slight increase in oil production.
Petroleum Bioresources, Inc.	1983-84	Westfork field Colorado	Rapid increase in oil production with rapid decline after 5 months.
Alpha Environmental, Inc.	1986	Lavernia field Texas	Slight increase in oil production in off-pattern leases.
Alpha Environmental, Inc.	1986-87	Longwood field Texas	BS&W[2] decreased.
BWN Oil (Australia)	1988-89	Alton field, Australia	Total oil production increased 42% in 350 days and BS&W[2] decreased.

[1]See Hitzman, 1988; Oppenheimer and Hiebert, 1989, Advanced Recovery Week, June 3, 1991.
[2]Basic sediment and water.

changing the wettability of the reservoir rock and thereby increasing oil recovery. Microbes also produce gases such as CO_2, N_2, H_2, and CH_4 that could improve oil recovery by increasing reservoir pressure and by reducing the viscosity and swelling of individually trapped droplets of crude oil. Sometimes, particularly with heavy crude oils, production of CO_2 may decrease the viscosity of the oil enough to lead to some improvement in oil production. In carbonate formations or sandstone rocks with carbonaceous cementation, acid-producing microorganisms can increase permeability and thereby improve oil recovery.

More care must be taken in a waterflood than in single-well stimulation treatments to ensure that the microorganisms can transport. However, the potential for a much greater increase in oil production is high because of the larger amount of reservoir contacted or treated. One of the first successful MEOR field pilots occurred in 1954, and consisted of an injection well and a production well (Yarbrough and Coty, 1982). More recent microbial-enhanced waterflood projects have been conducted by the National Institute for Petroleum and Energy Research (NIPER) (Bryant et al.,1990a, Bryant et al.,1990b); Imperial Energy Corporation; and Alpha Environmental, as well as by countries such as Australia, Romania, East Germany, and the USSR (table I-7). Many of these microbial waterfloods showed increases in oil production; however, no actual quantitation

TABLE I-7. Recent microbial-enhanced waterflood field projects

Project conducted by:	Year of test	Field/State	Reported results[1]
NIPER/Microbial Systems Corp. and INJECTECH, Inc.	1986	Delaware/Childers field Oklahoma	Oil production increased (13%) water/oil ratios decreased (5-35%).
NIPER/Microbial Systems Corp. and INJECTECH, Inc.	1990	Chelsea-Alluwe field Oklahoma	Injected in June, 1990.
Imperial Energy Corp.	1988	Loco field, Oklahoma	Oil viscosity decreased.
Alpha Environmental, Inc.	1988	Longwood field Illinois	Oil production increased.
Romania Test 1	1987	Romania	Oil production increased.
Romania Test 2	1987	Romania	Oil production increased.
Romania Test 3	1987	Romania	Oil viscosity decreased.
Romania Test 4	1987	Romania	Oil viscosity decreased.
East Germany	1987	East Germany	Oil production increased and water/oil ratio decreased.
USSR	1987	Bondyuzhskoe USSR	Significant oil production increase.

[1] See Hitzman, 1988; Bryant et al. 1990a; Bryant et al. 1990b; Wagner, 1990.

was provided on most of these tests. Many of these field tests were performed in stripper wells where a 15 to 20% increase in recovery efficiency did not seem to attract much attention. There is a need to perform field tests in reservoirs where there is significant oil saturation and that have not been flooded out. The MEOR process responsible for the improved production is generally attributed to gas and surfactant production by the microorganisms. Although significant advances have been made in recent years in understanding the mechanisms of MEOR, additional research to quantify and verify some of these findings is still needed.

Microbial Permeability Modification

Another application for microorganisms in a waterflood is fluid diversion. Since many types of microorganisms produce polymers, it has been suggested that some microorganisms could be used in situ to plug high-permeability zones in reservoirs preferentially and thus improve sweep efficiency (Jack et al., 1982). In 1958, researchers in The Netherlands conducted a selective plugging experiment using *Betacoccus dextranicus* and reported significant increases in oil production as well as an improved water-oil ratio. Microorganisms that produce polymers, biomass, and slimes have been shown to reduce core permeability under reservoir conditions in the laboratory. More recent field tests are reported in table I-8. The University of Oklahoma is currently planning a field test for its fluid diversion MEOR process (Knapp et al., 1989). This area of research has not attracted widespread attention. In view of the large quantity of unrecovered mobile oil as a result of poor waterflood sweep efficiency, additional research in this area, especially identification of the most promising microbes under different geological settings, seems appropriate.

Microbial Wellbore Cleanup

Use of microorganisms in a near-wellbore region can greatly improve injectivity and mitigate certain production problems. Several different companies promote microbial wellbore cleanup technology; however, information from most of these production operations is usually proprietary. One microbial treatment company, Micro-Bac International, provided a listing of petroleum regions where its microbial products are in use and several case histories of microbial wellbore cleanup (Schneider, 1990). That company has estimated that 2,500 to 3,000 wells have been treated using its microbial products, and this number does not include production tank or barge treatments for basic sediments and water (BS&W) or paraffin. Oil production increases have occurred in about 50% of all wells treated, with increases in total fluid produced ranging from 100 to 10%. From the available information, it is clear that in certain instances, microbial injection in a near-wellbore region can rival certain existing chemical treatments, both in efficiency and cost (Pelgar, 1990).

TABLE I-8. Microbial permeability modification field tests

Project conducted by	Year of test	Field/State	Reported results[1]
University of Oklahoma	1990	SE Vasser Vertz Sand Oklahoma	Planned.
Nova Husky Research Corp.	1988	Lloydminister Canada	Results appeared promising; microbial formulation was placed in reservoir, but permeability channels not obstructed.
USSR	1989	Romashkinskoye USSR	Additional oil recovered.

[1]See Hitzman, 1988; Knapp et al. 1989; Jack, 1990.

Microbial Polymerflooding

No data have been published regarding MEOR processes where the amount of injected microorganisms that produce polymer is actually equivalent to that of a conventional polymerflood. Moses (1989) has conducted laboratory research in this area, but no field test results have been published. Researchers in China recently reported on laboratory tests involving novel microorganisms that produce polymer which they intended to field test sometime later in 1990 (Wang, 1990).

Microbial Mitigation of Wellbore Coning

Researchers at the University of Calgary have patented a methodology for using ultramicrobacteria to plug the area around a production well and thus alleviate water coning problems (Costerton et al., 1989). No field trials have been reported to the public.

LIMITING RESERVOIR CHARACTERISTICS FOR MEOR PROCESSES

Simple compatibility studies between reservoir fluids and microorganisms can be adequate in many cases to predict whether microorganisms can be applied successfully. Compatibility tests are usually test tube experiments in which several microbial formulations are grown in the presence of reservoir fluids and sometimes reservoir rock. Measurements of the growth and metabolite production of the microorganisms and comparisons are made. Microbial enhanced oil recovery field projects have been conducted under a wide range of reservoir conditions (tables I-9 and I-10).

Well stimulation microbial treatments have been done in wells with connate brine salinities greater than 11%. Microbial-enhanced waterflooding projects have been conducted in waters with total dissolved solids (TDS) concentration values as high as 32%. In the high salinity case, it is probably not entirely sodium chloride that is responsible for the high value. In the past, most reservoir screening criteria used a TDS limit of 10%, or 100,000 ppm. Obviously, there are microorganisms that can grow at much higher TDS values, and the East German microbial-enhanced waterflood demonstrates this point (Wagner, 1990). As a screening criterion, it is recommended that the sodium concentration continue to be less than 10% although the TDS value may be much higher. The presence of high (5 to 10 ppm) concentrations of some metals (examples include arsenic, nickel, and selenium) will affect microbial growth, and fluid compatibility studies and a reservoir brine analysis can be used to identify any potential problems with metal ions. Some researchers claim that carbonate rock is desirable for microbial EOR processes. Since many microbes produce acids when fermenting molasses, Wagner believes that the presence of carbonate minerals can improve microbial CO_2 production, as well as increase permeability.

TABLE I-9. Reservoir characteristics for single-well stimulation field projects

Project conducted by	TDS, %	Permeability, md	Depth, ft	Oil gravity, °API
Oklahoma State University	3.0	([1])	1,750	([1])
Oklahoma State University	4.6	([1])	450	36
Microbial Systems Corp.	11.0	26	700	34
Fairleigh Dickinson Lab.	([1])	([1])	2,550	40
Fairleigh Dickinson Lab.	0.8	([1])	350	20
Petroleum Bioresources, Inc.	([1])	([1])	5,200	([1])
Alpha Environmental, Inc.	1.0	43	1,500	32
Alpha Environmental, Inc.	4.0	25	2,120	39
BWN Oil Co. (Australia)	([1])	260	([1])	Medium-light

[1] Denotes value unavailable or not reported.

TABLE I-10 - Reservoir characteristics for microbial-enhanced waterflood field projects

Project conducted by	TDS,[1] %	Perm, md	Depth, ft	Oil gravity, °API	Visc.,[2] cP	Temp., °F	Rock type
NIPER/Microbial Systems and INJECTECH, Inc.	0.02	92	650	34	7.0	77	SS
NIPER/Microbial Systems and INJECTECH, Inc.	2.6	31	450	31	8.2	75	SS
Imperial Energy Corp.	3.8	([3])	([3])	21	([3])	([3])	SS
Alpha Environmental, Inc.	([3])	5-165	2,620	37	([3])	80	SS
Romania - Test 1	0.5	245	2,461	([3])	16	117	SS
Romania - Test 2	0.45	100-1,000	2,560	([3])	26	97	SS
Romania - Test 3	0.5	100-500	2,297	([3])	46	113	LS
Romania - Test 4	0.9	400-1,300	3,937	([3])	33	124	SS
East Germany	32.0	10-50	4,068	30.6	([3])	150	LS
USSR	0.02	500	5,577	([3])	([3])	90	SS

[1]Produced water.
[2]Viscosity at reservoir temperature.
[3]Denotes value unavailable or not reported.
SS = Sandstone
LS = Limestone

Reservoir rock permeability ranges of one to thousands of millidarcies (md) have been reported for MEOR field projects. In some instances, for example in well stimulation treatments, the permeability factor is probably less critical since the primary objective is to improve oil recovery in the near-wellbore region. The crucial factor for single-well treatments should be good injectivity. In microbial-enhanced waterflooding, reservoir rock permeability becomes a more important consideration. However, successful field tests (Bryant et al., 1990a) have been demonstrated in rock that was previously considered too tight for microbial treatment (< 100 md) (Bryant et al., 1990a; Bryant et al., 1990b). A single-well injectivity test can provide valuable information to those producers considering microbial-enhanced waterflooding. If injectivity is unaffected after microbial injection, then permeability may not be a limiting factor for that particular reservoir. In revised screening criteria, therefore, no limitations will be placed on permeability, although it is recommended that a single-well injectivity test be conducted prior to a multiwell microbial waterflood.

No MEOR field projects in high-pressure and high-temperature reservoirs have been reported. The usual biological limitation for temperature is about 158° F (70° C), and the pressure limitation is about 20,000 psi. The testing of microbial compatibility with reservoir fluids under reservoir conditions is recommended prior to any microbial field test, even well stimulation treatments. The temperature constraints for microbial growth occur with individual microbial species and therefore will not be considered under revised screening criteria. The presence of indigenous microorganisms, as cited in previous screening criteria, is still a major concern. The microorganisms used for crude oil mobilization must survive and thrive in the reservoir. Compatibility testing using the indigenous microorganisms of that particular reservoir is also highly recommended. In those reservoirs with more harsh environmental characteristics for microbial survival, the possibility of stimulating indigenous microorganisms is feasible.

Although most MEOR field projects have been conducted with light crude oils having API gravities around 30° to 40°, successes have been reported with heavy crudes having gravities around 20° API. Obviously the higher the viscosity of a crude oil, the more difficult it will be to mobilize; yet, the principal mechanisms of microorganisms for improved displacement efficiency; gas, surfactant, and solvent production; and wettability alteration should still apply.

CONCLUSIONS

MEOR is attractive economically because the cost of the injectant is relative low in comparison with that of other EOR methods. The microorganisms are self-perpetuating as long as they are supplied with nutrient. The costs associated with MEOR include: (1) selection of a microbial formulation for a specific field application; (2) nutrient expense; and (3) modifications to surface facilities for injection. These modifications are generally minimal in cost.

The increasing number of microbial enhanced oil recovery field projects and the variety of different microbial processes that are applicable demonstrates the difficulty and complexity of placing reservoir limitations on the technology. Rather, it is recommended to the national laboratories, universities, small companies, and foreign governments conducting these projects that emphasis should be placed upon the adequate design of a particular field project prior to its implementation. Some thought must be given to what type of microbial process is desired, which means that first some knowledge of the reservoir problem must be obtained. Knowledge of the reservoir problem must be determined before a microbial solution to that problem can be designed. Essentially, a revision of screening criteria for MEOR processes in the oilfield becomes a matter of selection of particular microbial formulations for specific reservoir conditions after the problem is defined. The most important screening recommendations to be considered are listed in table I-11.

TABLE I-11. Recommendations for screening procedures for application of MEOR processes in the oilfield

Parameter	Screening procedure
Microorganism used	Determine potential mechanisms for increasing oil production.
Salinity	Use compatibility testing to assay for microbial growth and metabolism.
Temperature/depth	Use compatibility testing to assay for microbial growth and metabolism under reservoir conditions.
Trace minerals	Use compatibility testing to determine deleterious effects on microbial growth and metabolism.
Reservoir rock permeability	If multiwell process, conduct a single-well injectivity test and coreflooding studies.
Indigenous microorganisms	Use compatibility testing to assay for microbial growth and metabolism under reservoir conditions.

The nature of the reservoir to be used for MEOR technology will severely affect the success of the process. If the reservoir is highly channeled, injecting a microorganism that produces only a surfactant may not recover a significant amount of oil since the microorganisms will continue to remain in the water phase and thus bypass much of the trapped crude. By contrast, if there is no channeling and the reservoir permeability is low, injecting a microorganism that produces only a polymer and biomass may decrease injectivity and cause undesirable plugging. Sometimes the mineral content of the connate water may inhibit the growth of the selected microorganisms. If that happens, it may be possible to stimulate microorganisms that are indigenous to the water so that they can act to mobilize crude oil. Knapp et al. (1989) at the University of Oklahoma found that they were required to try this approach when the salinity of the brine was much higher than their microorganisms could tolerate. In the USSR, scientists are conducting microbial EOR field trials by stimulating indigenous microorganisms with injection of aerated and carbonated water (Ivanov, 1990). A list of screening criteria is presented in table I-12.

Clearly, there are many options available to oil producers interested in microbial enhanced oil recovery. Because of the nature of microbial growth and the ability of microorganisms to utilize relatively inexpensive chemicals as nutrients, the economics should be attractive under almost any circumstance. No one microbial process will be a panacea, nor be successful in every reservoir; yet, the fact that there are so many options remains the exciting and challenging facet of MEOR technology.

TABLE I-12. - Screening criteria for application of MEOR processes in the oilfield

Parameter	Recommended range
Salinity	< 15% sodium chloride; total TDS may be higher
Temperature/depth	< 170° F; < 8,000 ft
Trace minerals	< 10-15 ppm of arsenic, mercury, nickel, selenium
Reservoir rock permeability	> 50 millidarcies, unless highly fractured
Indigenous microorganisms	Compatible with injected microorganisms in selected MEOR process
Crude oil type	> 15 °API; not enough information available yet for heavier crude oils
Residual oil saturation	> 25% ; may be some exceptions
Well spacing	< 40 acres; a response can generally be seen sooner on closer well spacing

RESEARCH NEEDS FOR MICROBIAL EOR TECHNOLOGY

The DOE-sponsored microbial EOR projects have demonstrated that the use of microorganisms has potential for being cost-effective, even at marginal oil prices. What has not been demonstrated is the documentation and predictability of MEOR technology. The only achievable means of obtaining this information is through an integrated laboratory and field effort. More field projects that are well documented, even if they are relatively small field pilots, would provide some of the information that is crucial to demonstrating the ability of MEOR processes to improve oil production in the near term. Likewise, laboratory efforts must be directed towards validating field results and simulating these results to develop more predictive models. Many of the DOE-sponsored microbial technology projects such as those at the Universities of Oklahoma and Texas, and NIPER have advanced simulation to a great extent, but the incorporation of laboratory and field data into these models has not been done.

Other areas where research appears to be lacking include cost-effective nutrients for MEOR processes, and adaptation or selection of microorganisms for MEOR that can withstand temperatures greater than 170° F and 15% sodium chloride concentrations, and continue to produce the metabolites responsible for improved oil mobilization. There are many areas of the United States where the usual nutrient for MEOR, molasses, may be unavailable, or the quality control may be inadequate. Other nutrients, such as by-products from corn and liquor processing plants should be considered. It has been documented that there are microorganisms that can exist at temperatures and salinities much greater than the limits imposed in this section. What has not been documented is the ability of these microorganisms to grow under reservoir conditions and mobilize oil.

The areas of research needs in order of priorities are:

Near-term

1. Perform well documented field tests, especially in reservoirs with substantial remaining oil saturation.
2. Development of low-cost, consistent, and readily available nutrients.
3. Development of profile-modification and well-stimulation methods.

Mid-term

1. Development of salinity- and temperature-tolerant microbes.
2. Improvement of simulator for MEOR processes.

Long-term

1. Improved understanding of recovery mechanisms for various microbial techniques.

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CHAPTER 6
POLYMER FLOODING: STATE OF THE ART REVIEW

By P. B. Lorenz

INTRODUCTION

Even with low oil prices, polymer flooding is being practiced successfully and profitably. In terms of the number of projects started, polymer flooding was the most popular of all EOR methods in the mid-1980s (Pautz and Thomas, 1991). The most recent Enhanced Oil Recovery Survey in the *Oil and Gas Journal* (Moritis 1990) reports that in 1990 in the United States there were 42 current projects of which 29 were successful, producing 11,000 BOPD; 43 projects terminated, 31 had been successful; and 2 planned for startup. In Canada there were three current projects, one successful. In Europe, there were 12 current, six successful. Some projects not labeled "successful" were too early to evaluate. The AORPIP identified polymer flooding as a potential process that can assist in achieving near-term objectives of DOE's Advanced Oil Recovery Program.

A very recent report (Hochanadel et al., 1990) demonstrates the technical and economic superiority of polymer flooding over waterflooding in the Powder River Basin of Wyoming.

A recent compilation of EOR chemicals available commercially (*Petroleum Engineer International*, 1990) included 30 products for mobility control. Patents issued in 1989-90 included seven for new polymer products and 16 for new mobility control processes.

Three fairly recent reviews of the state-of-the-art (Gao, 1986; Kessell, 1987; Combe et al., 1990) provide more information on the successes and problems. Successful projects were carried out

- in sandstone and limestone;
- at temperatures up to 145° F;
- down to a depth of 5,000 ft;
- for oil viscosities from 3 to 40 cP;
- with permeabilities down to 1 md;
- mostly with partly hydrolyzed polyacrylamides (HPAM), but a few with xanthan;
- with tapered slugs in low-salinity water.

The recognized problems that are largely solved are:

- Shear degradation. This can be reduced by proper design of equipment and well completion, preshearing of HPAM, or use of biopolymers.
- Oxidative and bacterial degradation. Can be controlled by antioxidants and biocide. However, because of environmental concerns, some of the biocides such as formaldehyde may become unacceptable.
- Salinity and hardness sensitivity. This problem is greatly reduced by the use of biopolymers, although they are more expensive, more highly retained, and less thermally stable.

RECENT TECHNICAL ADVANCES

Tolerance to Salinity and Hardness

Synthesis work at the University of Southern Mississippi has developed acrylamide-based products with superior tolerance to electrolytes. Patents were obtained (McCormick and Blackmon 1986; McCormick and Blackmon 1987) for copolymers containing N-substituted moieties, which are being tested in industrial laboratories (McCormick and Hester, 1987). Viscosity augmentation is partly due to reversible association that results from hydrophobic interaction (McCormick and Hester, 1990), so injectivity and irreversible shear degradation are not expected to be problems.

A unique terpolymer, still in the research stage, is a neutral acrylamide copolymerized with both anionic and cationic moieties (McCormick and Hester, 1989). By virtue of its ampholytic character, its viscosity is low in fresh water and shows a marked increase at higher salinity.

Injectivity

Face plugging, caused by incomplete hydration, high-molecular-weight fractions in synthetic polymers, or cellular debris in biopolymers, has been reduced in the past by filtration. Improved technology in manufacturing methods has provided biopolymers that are much more injectable (Tate, 1985; Rivenq et al., 1989; Lund et al., 1990), especially if given a brief shear treatment and protected by chelating agents to suppress gelling (Philips et al., 1982; Tate, 1985; Fletcher et al., 1990). Still, in any specific case, a pilot test of injectivity is prudent before undertaking a full-scale flood.

Injectivity can also be hampered by strong viscoelasticity (Seright, 1980). It is worth noting that, at the same level of viscosity, a Newtonian fluid gives a more stable displacement front and has a smaller slug-size requirement (Gao and French, 1988). However, the trailing edge of a downstep within a graded slug is more stable with a viscoelastic fluid.

Thermal Stability

For HPAM (protected from oxidation), thermal degradation consists of hydrolysis and ensuing precipitation by divalent cations (e.g., Stahl, 1985). Some guidelines (Gao, 1986) are:

Total hardness level, ppm	Temperature limit °C
≥2000	75
1000	79
500	88
400	93
270	96
≤ 20	204
most unsoftened injection waters	93
most produced waters	<82

Biopolymers are generally regarded as being less heat tolerant than HPAM, but the published results are variable (cf. Stahl, 1985; Gao, 1986; Rivenq et al., 1989; Kalpakci, 1990), depending on how well they are protected from oxygen (Bae, 1984; Doe et al., 1987).

Pfizer has developed a high-pyruvate xanthan with superior tolerance to hard brines, which is made thermally stable with proprietary additives (Pfizer, 1985; Doe et al., 1987).

Scleroglucan is recognized as being more heat tolerant than xanthan (Davison and Mentzer, 1980; Rivenq et al., 1989; Kalpakci, 1990). The variance among the several reported results (see also Ryles, 1988) is partly due to inadequate quality control (Combe et al., 1990). Improved manufacturing techniques (as in the case of xanthan) and a heat-shear treatment prior to injection have greatly reduced the plugging problems encountered earlier (Lange and Rehage, 1980). In controlled experiments, scleroglucan lost less than 20% of its viscosity in 2 years at 105° C, and with an organic antioxidant the loss was almost nil (Kalpakci, 1990). However, it undergoes a transition from rods to random coils at 115° C (cf. 70° C for xanthan), and is said to degrade at 120° C (Stahl, 1985). Scleroglucan is a completely nonionic homopolysaccharide and is totally insensitive to the ionic environment.

Injection Strategy

Several recent studies (Russell, 1989; Sohn et al., 1990; Hochanadel et al., 1990) have emphasized that it is an economic advantage to start polymer injection early. Sohn et al. (1990) demonstrated an advantage in leading with 8% PV of a salt-insensitive polymer (unhydrolyzed polyacrylamide) and following with 50% PV of a conventional and cheaper polymer. This strategy has been applied in the field (Combe et al., 1990).

European investigators dispute the American belief that polymer flooding recovers only a rather small fraction of waterflood residual oil. The six projects in Germany have produced 10 to 20% PV beyond the estimated waterflood limits. The claim is made (Combe et al., 1990) that this is a result of the permeabilities of 1 to 5 darcies, much higher than those of most projects in the U.S. However, a random sampling of data assembled by Manning, Pope, and Lake (1983) indicates no correlation between recovery and permeabilities in the range 1 to 1,000 md. This is shown in figure I-4. It seems plausible that the intercontinental difference occurs because the German projects initiated polymer injection well before waterflood production had ceased.

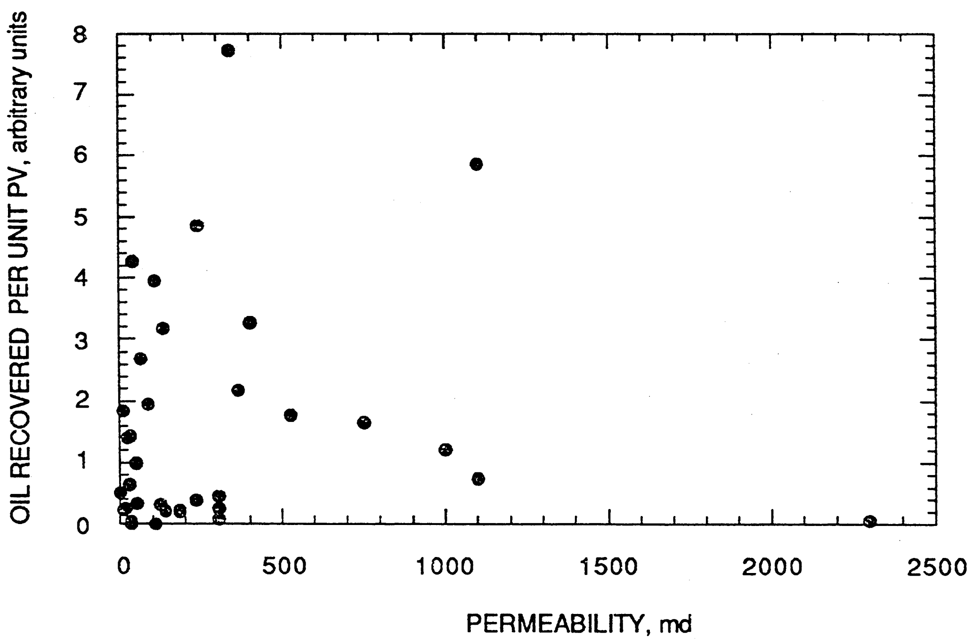

FIGURE I-4. - Oil recovery from field projects using polymer flooding (From data of Manning et al., 1983.)

Retention Control

Some retention is desirable for reducing mobility through reducing effective permeability, but unwanted plugging and excessive transit delays must be avoided. Polymer retention can be minimized through proper seletion of a polymer formulation with properties tailored to the reservoir and may include the use of polymer blends (Combe et al., 1990). The project engineering design can also mitigate polymer retention (Huh et al., 1990a).

Observations in a recent surfactant-polymer field test (Huh et al., 1990 b) revealed that the depth of propagation of polymer in a reservoir was limited, and was affected by permeability heterogeneities and oil saturation. This phenomenon needs to be studied in plain polymer flooding, for which the adverse effects would be more subtle than with surfactant, but probably significant.

Horizontal Well

The technique of drilling horizontal wellS can also enhance the benefits of polymer flooding (Foxonot and Bruckert, 1990). A horizontal well was drilled in Chateaurenard field to intercept the oil bank from a polymer flood pilot in progress (Bruckert, 1989). Reduction in water cut was observed after producing the horizontal well for about 1.5 years. The ability to overcome problems with horizontal permeability anisotropies and the high productivity of the well combined to make this well the best producer in the field.

CONCLUSIONS

Polymer flooding is a well established technique. The areas in which research can lead to improvements are as follows:

1. Design of injection protocol. This includes using multiple polymer types in successive slugs or blends, and optimization of slug size.

2. Improved products. Problems of resistance to temperature, hardness, and bacterial degradation are largely solved, but maintenance of injectivity, range of propagation, quality control, and cost reduction are all challenges.

3. Determine factors (especially geologic) affecting injectivity and propagation of polymer.

4. Development of environmentally acceptable biocides for use in polymer flooding.

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CHAPTER 7
PROFILE MODIFICATION: STATE OF THE ART REVIEW

By P.B. Lorenz

INTRODUCTION

Strictly speaking, "profile modification" refers to near-wellbore treatment. Such treatments when applied to production wells are intended to reduce the relative permeability to water and minimize water coning. The reduction of water coning appears to have been the most successful feature in field tests (Liang et al., 1990). The result of decreasing the water-oil permeability ratio depends on several variables, especially fractional flows outside the gel-treated region, and near-wellbore treatment will not necessarily enhance oil recovery from a particular zone. Profile modification is considered one of the techniques that has the potential for increasing domestic oil reserves in the near-term in AORPIP (DOE, 1990).

The goal in treatment of injection wells is to suppress the loss of injected fluids to "thief zones." However, improvement in profile does not necessarily correlate with increased production (Wagner, Weisrock, and Patel, 1986). The benefit of near-well improvement can be nullified by crossflow between strata and by vertical fractures that reduce sweep efficiency.

Much research has been devoted to permeability modification in depth. The terms "conformance improvement treatment" (Sydansk, 1988) or "permeability contrast correction" (Mumallah, 1988) are more comprehensive. The term "permeability modification" will be used in this review. The focus is on the gel-formation technique, which is the predominant method in current laboratory investigations and field applications. A tabulation of other techniques was given by Navratil, Sovak, and Mitchell (1983). Foam has been given the most attention because it is applicable to CO_2 (Llave et al., 1990, see also chapter 2) and steam (Hirasaki, 1989, see also chapter 8). A recent field test (Mohammadi and Tenzer, 1990) was successful. Emulsion blocking for steamfloods was studied at NIPER (French, 1985, 1987) after a field application for improved waterflooding by Chevron (McAuliffe, 1973).

Gelled polymer treatments have been used in the field for more than 20 years, originally with alternating slugs of polyacrylamide and a metallic crosslinking agent - aluminum citrate, or sodium dichromate and a reducing agent. Table I-13 lists published field tests in the past decade. All projects have been at least partly successful. In cases where process efficiency was evaluated, the

TABLE I-13 - Published field tests of permeability modification in the past decade

Company	Gel type	Inj. well	Prod. well	Oil recov.	Reference
Mobil	Flocon/Cr^{+3}	x		+	Abdo et al., 1984
Pfizer	Xanth./Cr^{+3}	x		±	Avery et al., 1986
Pfizer	Floperm		x	±	Avery et al. ,1988
Dow	PAA/$Cr_2O_7^{-2}$	x(depth)		±	Bowdish, 1985
Pfizer/ARCO	Floperm	x(near-well)		±	Chang et al., 1985
Murfin Drilling	?		x	±	Jack, 1990
Apache	Al-citrate	x		±	King, 1990
Phillips	PAA/organic		x	+	Moradi-Araghi, 1989
Esso (Canada)	Phenoformaldeyde	x(fractures)		?	Nagra et al., 1986
Mobil	New bio	x(depth)		+	Sampath et al., 1986
Marathon	PAA/Cr-acetate	x(near-well & fract.)		±	Sydansk and Smith, 1988
Pfizer	Xanth./Cr^{+3}	x		±	Tate, 1985
Amoco Dowell/Schlumberger	lignosulfonate	x		±	Wagner et al., 1986
Canada	inorganic	x(near-well)		N.A	Chang, 1989

± Some of several performed tests were successful.
+ Performed tests were successful.

figures cited were around 1 barrel of oil per pound of polymer (Tate, 1983; Bowdish, 1985; Sampath et al., 1989). A tabulation by Seright and Martin (1991b) of 43 injection-well treatments that includes some unpublished results may be summarized as follows:

	No	Yes	Slightly	Debatable
Profile changes?	12	21	7	3
Profile improved?	17	13	4	9

CURRENT AREAS OF RESEARCH

Modified and Alternative Polymers

Improved acrylamide-based polymers, mostly proprietary (Ryles, 1986; Purkapple and Summers, 1988; Moradi-Araghi et al., 1989), are more resistant to high-temperature hydrolysis. The improvements include modifying molecular weight and degree of hydrolysis. A low degree of hydrolysis is advocated for high-temperature applications (Sydansk, 1988). Cationic forms have also been employed (Avery et al., 1988; McCool et al., 1988). Molecular weight has to be kept low for low-permeability reservoirs. Probably more effective for gel stability is copolymerization with other monomers (Moradi-Araghi, 1989).

Polysaccharides are also capable of forming gels by crosslinking. A modified xanthan with a higher pyruvate content has been studied in the laboratory (Liang et al., 1989; Hejri et al., 1989; Joussat et al., 1990; Kolnes et al., 1991), and field tested (Abdo et al., 1984; Tate, 1985). Three novel polysaccharides have been proposed: (1) the Mobil *Alcaligenes* product (Strom et al, 1989), a heteropolysaccharide without acetate or pyruvate, which can be gelled with chromium or other crosslinking agents; (2) the University of Kansas product from fermentation with *Cellumonas flavigena* (Vossoughi and Buller, 1989; Vossoughi and Putz, 1991), which is gelled by neutralization of a dilute alkali carrier; and (3) a high-molecular-weight nonionic material developed by the Institute Francaise du Petrole (Kohler and Zaitoun, 1991) for treatment of production wells up to 130° C.

Some of the products of current interest are phenolics. Commercial products that incorporate formaldehyde are effective at higher pH and are thermosetting. These include Borden's Geoseal, a tannin-based product (Navratil et al., 1982), and C300 and C305 (Navratil et al., 1983); also Pfizer's Floperm 325, which is rate-controlled by an added retardant or accelerant (Chang et al., 1985). Phenoformaldehyde types have been used in research by Nagra et al. (1986) and Seright and Martin (1991). Lignosulfonates with a chromium crosslinking agent were used in a field test by Wagner et al. (1986). However lignosulfonates require larger amounts of chromium, which adds significantly to the cost (Nagra et al., 1986).

Floperm 465 is a vinyl-based system (Martin et al., 1988). Acrylate is copolymerized with a acrylamide monomer in the Phillips product (Moradi-Araghi et al., 1989).

An inorganic system was tested in a single well, as recently reported by Chan (1989). A gel formed from a colloidal silica manufactured by Conoco was studied in the laboratory by Seright and Martin (1991b).

A number of other techniques have been described in the past (cf. Sydansk, 1988) but are not being pursued at the present time.

Crosslinking Agents

To avoid handling of toxic dichromate, there is a growing use of trivalent chromium. This, however, requires more polymer (Purkapple and Summers, 1988). The chloride is sometimes used directly. Kolnes et al. (1991) believe that the actual crosslinking species is a chromium hydrate oligomer. Oligomerization is a very slow process, so the age of the chromium solution prior to mixing can affect the kinetics of gelation. A low pH (3 to 5) is required for gelation. The demands of pH control can be reduced by use of poorly ionized salt such as the propionate (Mumallah, 1988) or acetate (Sydansk, 1988). Aluminum is usually used as the citrate, but high-pH aluminates have also been proposed as an alternative by Unocal (Dovan and Hutchins, 1987). Other metallic agents mentioned in the literature are Zr(IV) (Moradi-Araghi et al., 1989; Seright and Martin, 1991b) and Si, V, and Mo (Navratil et al., 1982). The polyphenol-aldehyde combination has been used as purely organic crosslinker on acrylamide-based polymers (Avery et al., 1988; Moradi-Araghi et al., 1989), but tends to be slower than the metallic agents.

Alternative Strategies

Originally, common practice was injection of alternating slugs of polymer and crosslinking agent. An interesting variation of this (Sloat et al., 1972) was to inject a cationic polyacrylamide first, which would form a layer on the negatively charged surface to which subsequently injected anionic polymer could be linked. This is still an established technique for moderate permeability modification (Hochanadel et al., 1990), although its merits have been disputed (Lin et al., 1987).

The recent tendency is to mix polymer and agent at the surface. This has two variants. The first is to form a "pregel" designed so it will set at a selected location, targeted by injection rate and gelling time. As discussed below, the gelling time is affected by so many variables that it is difficult to predict under field conditions. Another challenge in design is tailoring of the slug size so that the extent of blockage meets predetermined specifications. Because of these difficulties, the majority of successes in the field have been in near-wellbore treatments (Vossoughi and Buller, 1989).

The second variant of injecting pre-mixed gelling systems is reversible gel formation, so that the slug has relatively low gel strength in regions of high shear and reheals at low shear. This has been applied with some success in the field (Avery et al., 1986). Laboratory studies (Liang et al., 1989) indicate that the formation of gels is slower the second time, and that there is some irreversible degradation, especially with strong gels. However, the degradation is not severe if the high shear period is brief (Avery et al., 1986) and not too severe (Gao, 1989).

The adjustment of pH has been a part of the strategy in some processes. The Unocal process of using the $AlO_2^{=}$ ion as a source of aluminum consists of injecting the pregel at pH 10, and depending on alkali consumption to reduce pH below about 9.6, when the aluminum becomes active enough to act as a crosslinking agent (Dovan and Hutchins, 1987). The recently developed University of Kansas polymer (Vossoughi and Buller, 1989; Vossoughi and Putz, 1991) is injected in strong alkali and set by injecting alternating slugs of strong acid. Good volumetric coverage was achieved in the laboratory. The gel can be fluidized by injection of strong alkali. Chan's (1989) inorganic gel can be fluidized by strong acid (if applied soon after setting), but pH adjustment is not part of its formation. Phenoformaldehyde gels must be formed at fairly high pH to be effective (Seright and Martin, 1991a). With Floperm 500, pH can be reduced to accommodate higher temperature (Avery et al., 1986). No field tests have been reported where pH change was used to form gel.

A novel technique for permeability contrast correction in depth is the injection of a surfactant-alcohol blend (Llave et al., 1990). When the two components are separated by normal chromatographic processes, the surfactant forms a gel that substantially increases the flow resistance factor.

Laboratory Evaluation

A great deal of work has been done on gelation time because of its importance in design. In bulk studies it is the time at which the viscosity increases rapidly, after an induction period that varies from minutes to weeks. The rate of gelation and gel strength are influenced by several parameters, as shown:

	M.W.	H	C_p	C_a	C_s	pH	T
Rate	+	±	+	+	+	+	+
Strength		±	+	±	–	–	±

where M.W. = molecular weight, H = degree of hydrolysis, C_p = concentration of polymer, C_a = concentration of crosslinking agent, C_s = salinity, T = temperature, + means the rate (strength) increases with an increase in the value of the parameter, - means a decrease and ± means increase or decrease. In one study (Prud'homme and Uhl, 1984), the reaction was identified as second order in C_p and C_a. At low polymer concentrations, the rate of formation of Cr^{+3} or Al^{+3} ions is a rate-determining step (Kolnes et al., 1991). The effect of salt depends on the ionicity of the polymer (Prud'homme and Uhl, 1984; Purkapple and Summers, 1988). The effect is nil for a nonionic polymer. Specific ion effects were also reported. There is apparently an optimal degree of hydrolysis, but different values have been reported by different authors (Purkapple and Summers, 1988; Gao 1990). The temperature effect obeys the Arrhenius relation (Kolnes et al., 1991).

The inexorable variations in C_p, C_a, C_s, pH, and T (when treatment follows extended waterflooding) create difficulties in applying laboratory results in the field. Temperature is probably the most sensitive factor, and Kolnes et al. (1991) predict a variation of three others of magnitude in the gelation rate across the temperature gradients of North Sea reservoirs.

The table also shows the dependence of gel strength (viscosity) on the same parameters. A maximum was observed both with respect to concentration of the crosslinking agent (Batycki et al. 1982) and the degree of hydrolysis (Gao, 1990). In one study (Kolnes et al., 1991) a higher viscosity was reached at higher temperature, but the gel was more readily degraded by shear. In the work of Batycki et al. (1982), when polymer and aluminum were injected alternately, the concentration of aluminum had more influence than the concentration of polymer on gel strength.

It should be emphasized that most of the trends listed above are based on relatively few observations. Seright and Martin (1991a & b) have done extensive work on the pH effect. Each gelant system has an optimal pH, and the gel quality is degraded by deviations from this pH, either during gelation or in subsequent contact with brine. The pH in a reservoir is chiefly dependent on the buffering capacity of the rocks. This may take various values, e.g. around 4 with kaolinite (Somasundaran and Gryte, 1985), and greater than 7 with limestone. It is not likely to correspond with the optimal salinity for the gelant.

In addition to the parameters shown, the conditions of "mechanical disturbance" have a strong impact on the behavior of the gelling system. In many studies in bulk, increased disturbance (stirring, shear rate in viscometer) reduced gel time (Hubbard et al., 1986; Gao, 1989; Kolnes et al., 1991). The gel strength (maximum viscosity) also trended downward. Gels that were stronger because of formation at low shear were observed to be less resistant to shear degradation (Aslam et al., 1984; Vossoughi et al., 1989).

However, the gelation process is complex and does not respond to shear in a uniform and monotonic manner. Kolnes et al. (1991) observed that a system maintained at a constant shear rate went through a maximum in viscosity with respect to time. Joussat et al. (1990) found that trends with shear do not persist at very high and very low rates. Bhaskar et al. (1988) observed that increasing shear slowed the gelation of the acrylamide/chromate-thiourea (slow-gelling) system, but speeded the rate for the fast-gelling system with bisulfite replacing thiourea. They suggested a two-step reaction, in which the production of Cr^{+3} is rate-determining with thiourea, and the crosslinking reaction is rate-determining with bisulfite. However, Gao (1990) observed the same relation to overall rate when comparing Cr^{+3} and Al^{+3} as agents, and the results of Seright and Martin (1991b) also conform with this pattern.

The behavior of gelling systems in porous media ostensibly differs from that in bulk, even when the comparison is made at the same shear rate. When a pregel is injected continuously, blockage of flow is observed in a localized region that acts as a filtration barrier. The age of the pregel at the site where the barrier forms is considerably less than the age for gelling in bulk, but the blockage occurs only after the pregel has been flowing past the site for some time (Hubbard et al., 1986; Huang et al., 1986; McCool et al., 1988; Marty et al., 1989; Joussat et al., 1990). An explanation of these effects is that the first step in gelation is the formation of aggregates, and the second step is the formation of an extended structure. The formation of aggregates is fairly clearly indicated in bulk by elastic measurements (Prud'homme and Uhl, 1984; Hubbard et al., 1986). It is not surprising that the blockage of flow in pores by the aggregates occurs at a different time in the history of the process than the sharp increase in viscosity in bulk. The process in pores is dependent on shear rate and (perhaps separately) on pore geometry, as shown:

	Effect of	
	higher shear	higher permeability
Amount that passes filtration site before plugging starts	no effect	increase
Age of pregel at filtration site	no effect	increase
Relative increase of resistance at filtration site	decrease	decrease

Although the results of Marty et al. (1989) show a trend in the age of the pregel at the filtration site with increasing flow rate, Todd et al. (1990) were able to model the data with a fixed gelation rate constant. The tendency of a gelling system to form a barrier to flow that is localized poses a problem when it is desired to modify permeability over an extended region. Joussat et al. (1990) found that with the xanthan/Cr^{+3} system there was a buildup of flow resistance downstream from the barrier, while no buildup was observed with the polyacrylamide/Cr^{+3} system (McCool et al., 1988; Marty et al., 1989).

Batycki et al. (1982) discussed the effect of geometrical confinement on gel formation in pores from a somewhat different perspective. Their data show that in the domain where no gel is formed, increase flow resistance is attributable to precipitation. In cases for which permeability modification is applied to a rock matrix (rather than channels and fractures), a major factor in permeability modification is adsorption of polymer or gel (Sloat et al., 1972; Avery et al., 1988). Laboratory investigations should include a search for thin pregels that are strongly adsorbed. With proper design, this might achieve the purpose without the formation of a bulk gel that would reduce flowrates and displace oil around a production well, thus immobilizing the oil in low-permeability layers (Hughes et al., 1990).

The conclusion from these observations is that, in our present state of knowledge, measurements in bulk are not sufficient for the design of in-depth permeability modification processes in porous media (cf. Avery et al., 1988).

In simulating the process, Seright et al. (1988) felt the need of better data on the behavior of pregels in regard to flowrate and permeability dependency, and values of the residual resistance factors. The same workers (see also Liang et al., 1990) found that the depth of penetration of a pregel into low-permeability layers is smaller in linear cores than in a radial system, so that the degree of permeability modification attainable is overestimated in many laboratory studies.

Stability

The durability of permeability modification by gels is subject to chemical and thermal degradation and mechanical stress. One problem at high temperature is the instability of the polymer units (Yang and Treiber, 1985; Ryles, 1988). It has been asserted (Moradi-Araghi et al., 1989) that crosslinking neither increases nor decreases the stability of the polymer. However Sydansk (1988) claims that the polyacrylamide-Cr(III) gel, once formed, is relatively immune to thermal and chemical degradation. The other problem is that the crosslinked structure itself is degraded by syneresis (Nagra et al., 1986). Table I-14 lists the gel-forming systems that have been designed to address these two problems. The principal thrust has been to develop materials that are thermally stable before gelling.

According to Seright and Martin (1991b), a phenoformaldehyde, a vinyl polymer, and a colloidal silica gave gels that were fairly pH tolerant, but the polyacrylamide and xanthan gels (in bulk) lost strength under alkaline conditions.

The shrinking and swelling induced in gels by pH changes or extended exposure to brine were studied at the University of Kansas (Young et al., 1985; Gales et al., 1988). Volume changes of $\pm$ 60-70% are recorded, and are affected by polymer/agent ratio, pH, divalent cations acting as crosslinking agents (Ryles and Cicchiello, 1986), and temperature. However, Eggert et al. (1989) found that flow resistance changed only a little (12%) with a gel that exhibited a large

TABLE I-14. - Gelling systems designed for thermal stability

Product	Chemical type	Temperature, °C	Duration of test	Reference
Borden's	tannins	170 275	 months	Navratil et al., 1983
Floperm 325	phenoformaldehyde	92	10 mo	Chang, 1985
Cyanagel	crosslinked by Cr(VI) - redox	120	>1 yr	Ryles, 1986
MARCIT	acrylamide (Cr acetate)	124	2 yr	Sydansk, 1988
Phillips	copolymer	113	2 1/2 yr	Moradi-Araghi, 1989
	lignosulfonate	90	—	Nagra et al., 1986
	inorganic	120	days	Chan, 1989

(63%) volume change in bulk. Seright and Martin (1991b) found little correlation between the pore volume occupied by a gel and the flow resistance. On the other hand, Ryles and Cicchiello (1986) found that a gel that had undergone syneresis was much more sensitive to mechanical stress.

The effect of mechanical stress is described in terms of a "breakpressure," which is an important property in near-wellbore treatment. Break pressures up to 1,000 psi/ft are achievable (Avery et al., 1988), but for treatments that reduce water permeability without seriously reducing oil permeability, break pressures of 300-400 psi/ft are more practical. Martin et al. (1988) found that rigid gels are less susceptible to breakdown by postflush.

The sensitivity of gel properties to pH and divalent cations has been discussed above. Other substances that pose challenges, to both the formation and stability of the gels, are ferrous, ferric, sulfate, and hydrogen sulfide (Sydansk, 1988).

SCREENING CRITERIA AND DESIGN FACTORS

The constraints on permeability modification by gelled polymer largely overlap those for polymer flooding. These have been considerably relaxed in recent years by the development of new products that are more resistant to thermal and chemical degradation (table I-14), and that pose fewer injectivity problems (Tate, 1985; Lund et al., 1990; Fletcher et al., 1990).

It is quite important to characterize the reservoir problems that a permeability modification treatment is to ameliorate (Sydansk, 1988). Figure I-5 outlines the choices that must be made.

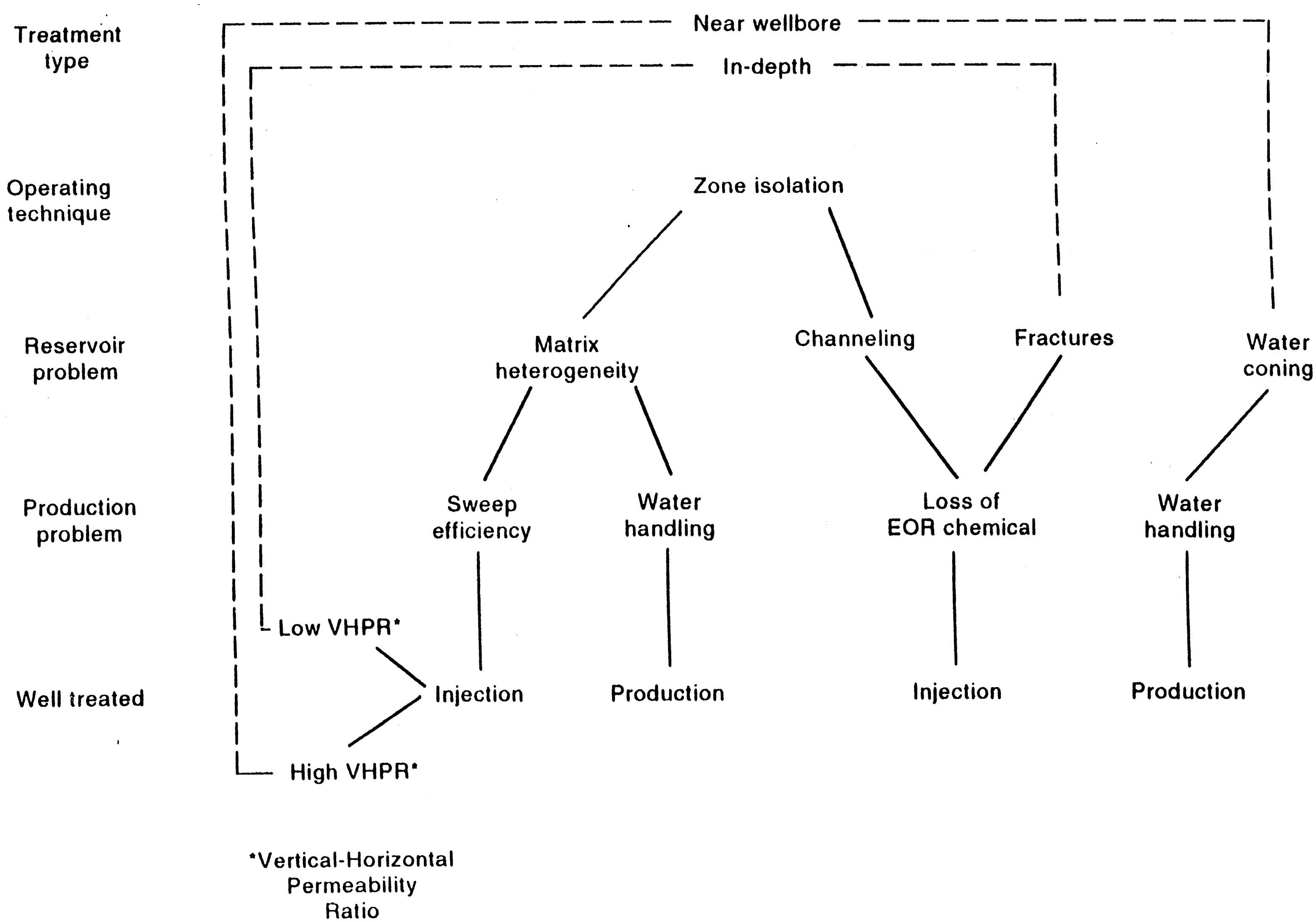

FIGURE I-5. - Design factors in permeability modification projects.

It has been emphasized that the effectiveness of a near-wellbore treatment depends on a lack of communication between layers within the reservoir (Hughes et al., 1990). The simulation work of Gao et al. (1990) showed that plain polymer flooding outperforms gel treatment when the ratio of vertical to horizontal permeability gets "large" (>0.01). This suggests that when there is vertical communication, a pregel should be designed with fairly high viscosity - which also promotes a more "piston-like" flow (Navratil et al., 1982).

Gao et al. (1990) also found that treatment of both injection and production wells gives better recovery than treating either well alone. The optimum time for gel treatment in waterflooding is close to the water breakthrough (which is, of course, the best time for the purpose of evaluating the performance).

Zone isolation to confine the injection to watered-out layers avoids damage to productive zones (Seright, 1988; Liang et al., 1990), and in the case of production wells allows immediate resumption of pre-treatment production rates with reduced water cut (Hughes et al., 1990). Naturally, zone isolation is inappropriate when the goal is to plug vertical fractures. It may be dispensed with when the high-permeability zones are watered out and the water/oil mobility ratio is high. In this instance, a low-viscosity pregel is preferable (Seright, 1988).

A plausible alternative to near-wellbore treatment of injection wells is recompletion.

Two caveats (Avery et al., 1988) are worth repeating: (1) For reservoirs with low remaining reserves, treatment probably will not be economic unless payout occurs as a result of reduced water handling costs; (2) A gel treatment can reduce the productivity index; therefore, flowing wells that are treated may require artificial lift in order to produce incremental oil or restore oil to the desired level.

CONCLUSIONS

Permeability modification by gelled polymer is a well established technique that has enjoyed considerable success. The predominant application is for near-wellbore treatment of injection and production wells. In-depth treatment is necessary when there is significant vertical communication among strata, and especially in the case of vertical fractures. It is important to define the reservoir problem to be addressed in designing a specific treatment.

Research needs to include the following:

Near-term

1. Accumulation of more extended data on the influence of reservoir parameters on properties of gels (especially gelation kinetics).
2. Improved models for prediction/design of profile modification process.

Mid-term

1. Improved accuracy in treating the target zone without damage to productive zones.
2. Development of methods for achieving the desired effect over an extended region.

Long-term

1. Delineation of rheological properties of gels and pregels.
2. Develop a better understanding of the differences between behavior of gel in bulk and in porous media.
3. Improved crosslinking systems which are nontoxic and environmentally benign.
4. Improved gel systems which are stable at high temperature and salinity.

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CHAPTER 8
THERMAL EOR TECHNOLOGY: STATE OF THE ART REVIEW

By Partha Sarathi

INTRODUCTION

The United States has about 80 billion barrels of heavy oil-in-place in 248 large reservoirs (greater than 20 million barrels of oil-in-place) (Kuuskraa, 1988a). An additional 20 billion barrels of heavy oil is estimated to exist in smaller reservoirs (less than 20 million barrels of oil-in-place). The total U.S. heavy oil resource represents about 20% of the estimated 500 billion barrels of crude oil discovered to date (Kuuskraa, 1988b). The U.S. heavy oil resource base includes a diverse collection of oil fields, ranging geographically from Alabama to California and from Alaska to Texas. Over half of the U.S. heavy oil resource is found in California, and more than half of that is in the San Joaquin Valley, mostly in four massive, shallow fields—Midway-Sunset, Kern River, South Belridge, and Coalinga.

The recovery of heavy oil by thermal methods involves the introduction of heat into a reservoir to reduce the viscosity of the oil and improve its ability to move through the reservoir to a producing well. The effect of heat on oil viscosity and the idea of using heat to enhance the recovery of viscous crude oil were described in detail in a 1917 U.S. Bureau of Mines publication devoted to oil recovery methods (Crawford, 1964). Heat may be introduced into a reservoir by burning a portion of oil-in-place or by the injection of a hot fluid such as steam or hot water. Both techniques are being used commercially, with injection of steam being the most preferred technique. The first reported U.S. steamdrive was performed in a reservoir near Woodson, TX, at a depth of 380 ft in 1931 (Stoval, 1934). The first reported U.S. in situ combustion field operation was performed accidentally in an Oklahoma field in the mid-1920s (Crawford, 1964).

Thermal oil production technology (TEOR) has developed rapidly in the United States since the 1930s. Most of the U.S. thermal EOR effort has been focused on recovering the heavy oil reserves of California, where TEOR technology has been developed, tested, and proven. In 1988, TEOR production accounted for 73% of all U.S. EOR production (Blevins, 1990). The DOE EOR Project Database contains information on 544 thermal EOR projects that had been started as of January 1990 (Pautz and Thomas). In 1990, oil production by thermal EOR methods is estimated to have been 454,000 barrels per day. According to Pautz and Thomas (1990), this production is within 15% of that predicted by the 1984 National Petroleum Council (NPC) study. The principles of thermal recovery processes and their main characteristics are well documented in books (Boberg, 1988; Butler, 1991; Prats, 1982; Burger, 1985) and review papers on field applications

(Farouq Ali, 1979; Chu, 1982; Chu, 1985; Kuuskraa, 1984). Therefore, this review will focus on the recent developments in thermal recovery technology and future outlook for TEOR in the United States.

TECHNOLOGY CHANGES IN THERMAL EOR

Steam Injection

Screening Criteria

Numerous screening guides and criteria have been presented by many authors and institutions (Prats, 1981; Farouq Ali, 1970; Lewin and Associates, 1981) as an attempt to document reservoir and fluid properties needed for successful implementation of the steam injection process. Several authors (Prats, 1982; Dougdale and Belgrave, 1989) have indicated the use of engineering judgment in the application of these criteria to target reservoirs. Since many of the criteria are being violated in commercial operations, each criterion must be examined on an individual basis. Dougdale and Belgrave (1989) questioned the assignment of values to a set of reservoir parameters and suggested that the only criteria that a steam injection process must meet are the following:

(a) can the process heat the reservoir efficiently and economically?

(b) can the process produce oil economically?

Improved Reservoir Conformance

Injection of steam into a non- or low-dipping reservoir with nonzero vertical permeability and low horizontal permeability will result in steam override and poor vertical sweep. A review of steamflood field projects (Part II, this report) identifies gravity segregation and reservoir heterogeneities as problems that limit the efficient application of steamflooding. An example of such a case is the steamdrive in the Mecca lease of Kern River (CA) field (Dilgren et al., 1980; Patzek and Koinis, 1988). Injection of foaming agents with steam has been used to improve the steamdrive efficiency in such reservoirs (Duerksen, 1986; Robin, 1987; Friedmann and Jensen, 1986). However, in steeply dipping reservoirs where gravity drainage is the dominant production mechanism, the steamdrive process is very efficient with updip steam injection and downdip production. In such situations, foam will contribute very little to augment production. Other situations, where there is very little potential for foam, include thick, high vertical permeability reservoirs and reservoirs having good communication between injections and producers (high-permeability reservoirs).

In most reservoirs, steamdrive suffers due to gravity override and channeling of steam through high-permeability streaks. Channeling is defined as the loss of steam to isolated 'thief zones' that take a disproportionate amount of the injected steam (Hirasaki, 1989). The thief zone could be a zone of high-permeability sand, or a gas-filled, desaturated zone that is isolated from other zones except at the wellbore. In reservoirs with no crossflow, the foam mobility in the vicinity of injection well is much more important than that farther into the reservoir because in such reservoirs the resistance to radial flow from an injection well is concentrated near the wellbore vicinity (Hirasaki, 1989). Thus, in such a situation foam can improve the injection profile without invading the entire reservoir.

The use of foam to control the mobility of steam in a channeling interval has been practiced in the oil patch since the early 1970s. It should be pointed out, that the process of injecting small slugs of foam forming surfactant to control injection profiles in cyclic steam operations is different from the continuous injection steam foam to enhanced oil recovery. The slug application method in cyclic process is called a "steam-foam treatment" and the continuous injection of steam foam into the reservoir to improve oil recovery is called the "steam-foam process." Unfortunately in the literature "steam-foam treatment" and steam foam process" are used synonymously. As previously mentioned the "steam foam treatment" method began to be used in the early 70s and continues to this date. More than 4,000 such treatments have been performed (Eson, 1989). The "steam-foam process" on the other hand was started in 1979 with two DOE-funded field demonstration projects (Doscher, 1982) in Kern Front field. An example of a "steam-foam process" pilot is Union Oil Company's "Dome-Tumbador" steam foam pilot (Mohammadi, 1989b).

Several successful "steam-foam process" pilots have been reported (Castanier and Brigham, 1988; Patzek and Koinis, 1988; Yannimaras and Kobbe, 1988; Mohammadi et al., 1989a, b; Eson and Cooke, 1989). In most cases, the steam foam was applied to a mature steamdrive (10 or more years of steam injection). An exception to this is the Bishop lease steam foam pilot in Kern River field (Patzek and Koinis, 1988) which had been under active steamdrive for only a year before foam injection began. Substantial increases in oil production and improvement in oil-steam ratio were observed in all cases. However, most reports in the literature on steam-foam projects do not give a breakdown of the percent increase in oil production that is directly attributable to foam and/or indicate whether steam-foam resulted in incremental ultimate oil recovery. Since most reported steam-foam pilots showed an improvement of the cumulative oil-steam ratio, this can be considered as equivalent to an increase in net oil recovery because the accelerated production conserves steam and results in the saving of crude oil burned as fuel for generating steam. Since the improvement in oil-steam ratio is likely to be high for a steam-foam pilot undertaken in a nonmatured steamdrive reservoir, the steam-foam process should be started soon after steam breakthrough rather than after the economic limit of conventional steamdrive (Hirasaki, 1989).

Most of the reported steam-foam process pilots were conducted in Kern River and Midway-Sunset (CA) fields. Kern River field has multiple reservoirs each with net pay of 65 to 100 ft. The individual sands within the reservoirs are in vertical communication. Gravity override of steam is the primary problem associated with steamdrive in Kern River. Midway-Sunset field has a 500-ft-thick sand reservoir which is characterized by large permeability contrast (variation in horizontal permeability) and vertical flow barriers. Channeling into high-permeability thief zones and gravity override are the major steamdrive problems in Midway-Sunset reservoirs. Response to injection of foam in these reservoirs varied from pattern-to-pattern with the best results being in the confined pattern (Castanier and Brigham, 1988). Because of the existence of vertical flow barriers in Midway-Sunset field, improvement in vertical sweep efficiency was achieved by controlling the injection profile only, and the consumption of surfactant was much lower, indicating the avoidance of foam propagation across the entire reservoir (Mohammadi et al., 1988b).

In the reported pilots of the steam-foam process, surfactants were added to the injected steam either (1) continuously at some specified concentration (Patzek and Koinis, 1988; Dilgren et al., 1980; Mohammadi and McCollum, 1988a; Mohammadi et al., 1988b) or (2) as periodic slugs in a semicontinuous manner (Ploeg and Duerksen, 1985; Lee and Kamilos, 1985) or (3) as periodic concentrated slugs (Doscher et al., 1983; Brigham et al., 1986). Small amounts of noncondensible gas were always added to surfactant to stabilize the collapse of foam bubbles due to steam condensation (Falls et al., 1988). Eson and Cooke (1989) recommended the injection of surfactant on a semicontinuous basis rather than as a concentrated periodic slug. However, if the intent of the process is to improve injection profiles in a reservoir without vertical communication, then slug injection is the preferred alternative (Hirasaki, 1989).

Even though most of the reported steam-foam process pilots were technically successful, the economics were variable due to generally high surfactant consumption per barrel of incremental oil produced.

Another method being developed for improving conformance is the development of emulsion blocking (French et al., 1986, French, 1987). The advantage of this method would be more complete blocking and lower cost than that of other methods. Emulsion formation may be part of the mechanism in 'foam' projects that do not have inert gas injected with steam.

Horizontal Wells and Steam Injection

The increasing interest for using horizontal wells in combination with steam injection for optimizing production from heavy oil reservoirs is evidenced by the number of recent research studies and field developments.

One advantage of horizontal wells over vertical wells is the greater direct contact area between wellbore and pay zone (Butler, 1984; Huang et al., 1986; Gussis, 1985; Joshi, 1986). This geometric feature during steamflooding leads to increased heat transfer from a wellbore filled with hot fluids to a cold reservoir. This, in turn, may improve significantly the injectivity and the oil flow. Simulation studies indicated horizontal well patterns are mainly attractive for thin, viscous oil reservoirs with low initial mobility, where steamdrive using vertical wells only would be economically unprofitable. (Combe et al., 1988)

Horizontal wells are also attractive in thermally stimulating thick massive unconsolidated sands as evidenced by the results of a recently terminated DOE-sponsored horizontal steam stimulation demonstration pilot in California (Nees et al., 1991). This project was implemented in the massive Potter sands of Midway-Sunset field at a depth of 1,200 ft. Although the horizontal well was completed in only a 30 ft open-hole zone, its daily production exceeded that of a recently completed vertical producer with 400+ ft open-hole completion.

Light Oil Steamflooding

Steam distillation, rather than viscosity reduction, is the major recovery mechanism in light oil recovery. Several laboratory studies (Madden and Sarathi, 1984; Sarathi et al., 1990) indicated that recovery efficiency of light oil steamflooding is strongly influenced by the chemical nature of the crude oil. Gravity override of steam remains a potential problem in light oil steamflooding (Sarathi et al., 1990). Numerical simulation studies indicated that up to 60% of oil-in-place at the start of a steamflood can be recovered economically (Hong, 1986; Chu, 1988). Even though this technique has proved uneconomical in several field tests, (Hong, 1986; Cathles et al., 1987), interest in the process remains high as evidenced by the success of light oil steamfloods at Elk Hills (NPR No. 1) and Teapot Dome (NPR No. 3) (Chappelle et al., 1986). Light oil steamfloods require high quality reservoirs with low permeability contrasts for successful uniform heating, distillation, and sweep factors (Blevins, 1990).

Steam-Assisted Gravity-Drainage Process (SAGD)

A process not yet completely developed is the "steam-assisted gravity-drainage (SAGD) process" which exploits the tendency of oil heated by steam to flow from the top to the bottom of a reservoir to improve production (Butler, 1985). Unlike the cyclic steam process, in a low dip reservoir which can only recover 15 to 20% of oil contacted, SAGD promises an ultimate recovery of 50% or more (Chung and Butler, 1988). Several field pilots using SAGD are underway in Canada; the most visible being the one conducted by the Alberta Oil Sands Technology and Research Authority in an underground test facility.

Heated Annulus Steamdrive (HAS Drive) Process

This process, mainly applicable to tar sand reservoirs, involves circulating steam through a horizontal conduit placed in a heavy oil formation between an injector and producer (Anderson, 1988). This circulation then results in a heated annulus around the conduit creating a zone of reduced heavy oil viscosity. Fluids move along the annular region around and along the horizontal conduit toward the producing well. A combination of steamdrive and gravity-drainage mechanisms contributes to oil and steam condensate production. This process is currently being field tested by Alberta Oil Sands Technology and Research Authority in an underground test facility.

Water-Alternating-Steam Process (WASP)

The Water-Alternating-Steam Process (WASP) was conceived to treat the problem of early steam breakthrough and poor reservoir conformance. It should be pointed out here that WASP is different from the technique of injecting water or low quality steam in mature steamflooded reservoirs as a way to terminate the project and recover some additional oil. WASP is implemented early in the life of a steamflood project to eliminate steam production and increase the salable oil from a reservoir whose performance was impaired by early steam breakthrough and well production problems. WASP uses alternating slugs of steam and water injected over several cycles to recover oil. The process is analogous to the water-alternating-gas (WAG) process used in gas floods. WASP was successfully field tested in a pilot area (Section 13D) of West Coalinga field and is currently being extended to other areas of Coalinga field and in a steeply dipping reservoir in Cymric field (Hong, 1990).

Single-Well Injection/Production Steamflood (SWIPS) Process

Since horizontal well, heavy oil, thermal recovery processes such as SAGD and HAS Drive must bear the high costs and complexities associated with drilling, completion and operation, the concept of a vertical HAS Drive process was proposed. In this process, steam is injected through the tubing string and allowed to circulate in the wellbore from just above the bottom packer to the injection perforation near the top of the production sand (Duerksen, 1991). This circulating steam creates a heated annulus around the conduit and provides communication between the steam injection perforation near the top of the sand and the fluid production perforation near the bottom of the sand. This concept is being tested in a California extra heavy oil reservoir.

Injection of Noncondensible Gases With Steam

Interest in using noncondensible gas with steam to improve oil recovery and production performance has increased in recent years. Development of the steam foam process and light oil steamflooding of several field pilots (Anon, 1989) and laboratory studies (Harding et al., 1983;

Harding et al., 1987; Redford, 1982) involving steam, CO_2, nitrogen, and/or flue gas indicate a modest improvement in total oil recovery compared to that of steam injection only. The steam noncondensible process is not effective in improving oil recovery when applied to a live oil situation.

Improvement of Thermal Efficiency

Since thermal processes are energy intensive, any improvement in energy utilization will improve the profitability of a project (See Part II, this report). The thermal efficiency of a steam injection process is characterized by the coefficient of performance, defined as the ratio of the heating value of the oil produced to the amount of energy expended to produce that oil (Burger, 1985). Significant efforts have been devoted in recent years to optimizing the use of the thermal energy input. These include (a) cogeneration of steam and electricity (Western, 1990); (b) better control of steam quality at the wellhead (Jones, 1991; Anderson et al., 1984); (c) new insulated tubings for steam injection (Kutzak, 1989); (d) conversion of steamflood to waterflood, with optimized size and quality of the steam slug (Ault, 1985); and (e) water-alternating-steam process (Blevins, 1990).

The advances in insulated tubulars now permit injection of steam into deep reservoirs (Borregales, 1987). Laboratory and simulation studies have shown that by properly choosing steam quality and injection duration, the energy efficiency of the steamflood process can be maximized (Lemonnier, 1981).

Operation Improvement and Reservoir Management

The oil price collapse of the mid-1980s forced steamflood operators to reevaluate operating practices and improve reservoir management techniques. Industry now places major emphasis on measuring downhole parameters and altering operations strategy based on in situ data (Blevins, 1990). Data obtained during steamflood operations are used to update reservoir descriptions and alter production practices. Temperature and pulsed neutron logs are used to determine steam sweep, location of reservoir heterogeneities, liquid desaturation, steam zone pressures and heating rates. Data from reservoir monitoring are analyzed to formulate better reservoir management practices and to lower operating costs. It is expected that for the rest of the century emphasis will be on improving the efficiency of the operation, rather than improving the technology (Stosur, 1988).

Steamdrive Problems

Even though steamdrive is the most successful of all EOR processes, there are many areas where steamdrive needs improvement. Some common problems exist that have considerable impact on oil recovery by steam injection. These are detailed in the following paragraphs.

Gravity Override

Since steam is lighter than oil, the gravity override phenomenon in many cases causes steam to rise to the top of a sand shortly after it leaves an injection well and thereby sweep only the topmost portion of the sand. The problem of how to process the lower portion of the sand is one of the most important problems yet to be solved satisfactorily. Some of the methods that have been tried with limited success, but lacking in general application, are as follows:

- One method has been to follow steamdrive with injection of water or low quality steam in an attempt to gravity underride the steam zone and displace heated oil to the producer. This method was apparently successful in only limited cases, and the failed cases had such a detrimental effect on oil production that industry no longer uses this process to produce oil from bypassed zones (Blevins, 1990).

- Another method has been to inject foam forming surfactants and inert gases into the reservoir along with steam to divert steam to unswept zones and improve reservoir sweep. While this method was apparently successful in many cases, the process failed to recover additional oil economically in many cases. Abnormally high injector to producer pressure differentials are required for long-range foam propagation (Hirasaki, 1989). Foam qualities and consistencies change rapidly away from the injection well, and foam is sensitive to the presence of oil (Jensen, 1987).

Steam Quality

Another serious problem associated with steamdrive and yet to be solved is the lack of knowledge of the quality of steam delivered at the wellhead and at the sandface. The 80% quality steam generated by oilfield steam generators is delivered to a wellhead through a complicated surface distribution system. Because of the heat losses in the distribution network, the quality of steam delivered at a wellhead is different from the generator effluent quality. Fieldwide checks of wellhead conditions revealed quality of steam delivered at wellheads varied from 4.1 to 100% (Jones, 1991). Because of nonavailability of accurate, inexpensive, and reliable steam quality and flow measurement hardware, rates of flow and steam quality are often estimated at the wellhead.

In recent years steam quality measurement instruments based on vibrating densitometer principles (Strome, 1987) and thermal neutron transmission principles (Wan, 1990) have been made available to the operators. These instruments in conjunction with a flow metering device such as a flow nozzle or an orifice meter is used to measure steam quality at the surface line. However, these instruments are expensive and must be calibrated for various field conditions.

Recent field tests revealed that these devices are difficult to calibrate and require periodic recalibration.

Rudimentary measurements downhole indicate that a two-phase steam system at downhole separates into liquid and vapor phases, with the liquid phase entering one sand and the vapor the other. At the present time, most operators estimate downhole steam quality using computer programs, based on wellhead data (i.e. flow rates, temperatures and wellhead steam quality). This precluded the estimation of how much heat is injected into formations and into which interval it is going. Use of limited-entry perforation schemes and downhole critical velocity chokes may allow operators to exercise some control over where steam enters a reservoir (Hone, 1987); however, lack of field or laboratory data prevents an evaluation of the effectiveness of these schemes. Use of radioactive tracer surveys to control steam injection profiles has been suggested (Nguyen, 1988); however, data interpretation is difficult because of lack of knowledge or low streamlines in injection wells (Schmidt, 1990). Shut-in static temperature surveys can be used to locate steam injection intervals, but not to determine the total heat injected. Experimental and theoretical work is needed in this area.

Other Technical Problems

Steam can be very reactive in a reservoir since typical oilfield steam generator feed water always contains some bicarbonate, which decomposes in the hot generator environment (Reed, 1980) into CO_2 and hydroxides. This decomposition results in a low-pH steam vapor phase and a high-pH liquid phase. These high and low-pH phases cause significant dissolution of rock matrix and generate CO_2 from the carbonate mineral phases (Cathles et al., 1987). The generated CO_2 significantly affects in situ process performance and contributes to production well and surface facilities problems (Schmidt, 1990).

The high temperature in steamdrive restricts the types of instruments and materials that can be used in wells. There is a critical need for equipment that can withstand a harsh steamflood environment. Better monitoring tools and techniques are needed to define steam, hot water, and oil zones and to characterize their movement through reservoirs.

Research is needed to better define the effect of temperature on wettability changes and oil-water relative permeabilities. Better well completion and sand control techniques are needed. Research that focuses on reducing thermal stress corrosion and extending the service life of downhole steam generators will contribute to applications of steamfloods to deeper heavy oil wells.

Other problems are more relevant to 'marginal' or 'less than ideal' reservoirs. These problems are summarized in tables I-15 through I-17.

TABLE I-15. - Reservoir problems

-	Too deep, thin and/or tight
-	Reservoir too small
-	Reservoir pressure too high
-	Severe heterogeneity and/or lenticularity
-	Water sensitive and/or unconsolidated sands
-	Scale-forming or corrosive connate water
-	Oil relatively non-viscous or too viscous
-	Oil saturation too low

TABLE I-16. - Unattractive economics

-	High oil viscosity
-	Costs increasing faster than crude prices
-	Complicated projects require more people
-	Fuel prospects uncertain
-	Pollution problems increase costs
-	Water supply and disposal
-	Royalty and surface damage
-	Front end loads and delayed response
-	Crude price structure and cyclic demands

TABLE I-17. - Technical difficulties

-	Reservoir definition
-	Poor conformance and capture efficiency
-	Low injection/production rates
-	Excessive heat losses, poor net energy ratio
-	Sand control
-	Wellbore damage
-	Steamer operations
-	Boiler feedwater and low-grade fuel options
-	Disposal options for oil and water

In Situ Combustion (Fireflood)

Although both steam injection and in situ combustion processes have been commercially successful in the United States, steam injection is clearly the preferred process. There appears to be several reasons. The instant success of the cyclic steam process, with its low initial investment and immediate production response coupled with the complexity and high level manpower required to operate a combustion project retarded the widespread acceptance of the combustion process in the United States (White, 1985). Further, since the early in situ combustion projects were poorly engineered and implemented in often noncommercial producing properties, they were a disappointment to the sponsors. Even though the properly engineered combustion projects on desirable properties were highly successful, the failed projects outnumbered the successful ones and slowed its ready acceptance in the United States.

The latest *Oil & Gas Journal* EOR survey (Moritis, 1990) reported eight active in situ combustion projects in the United States and no new projects were planned. Together these projects produce about 6,000 bbl/d of oil which is approximately 2% of the U.S. thermal EOR production. The daily U.S. in situ combustion oil production is about 4 times the combined production of all chemical EOR processes except the polymer process. Fireflooding is widely practiced in other parts of the world, and large-scale commercial in situ combustion operations are currently ongoing in Canada, Russia, and Romania (Moore, 1988). Unlike other parts of the World, in the U.S. in situ combustion technique is often used as a mean to repressurize the reservoir and not as a recovery technique. West Heidelberg , MS (Benton, 1981) and Forest Hill, TX (Hvizdos, 1983) in situ combustion projects are prime examples of pressure maintenance. This is because it is easier and more cost effective to produce oil from deep reservoirs by repressurization than by pumping. In spite of lack of interest in the United States for the combustion process, research is continuing on various aspects of the combustion process, and pilots are being undertaken.

Laboratory Research on Factors Affecting the Combustion Process

In situ combustion is a very complex process involving many chemical and physical processes. To improve its efficiency, it is necessary to have more knowledge of the factors influencing the process and how these affect the combustion of oil. Consequently, in recent years, extensive work has been devoted to understanding qualitatively and quantitatively the chemical reactions in natural porous media.

The mineral matrix significantly affects the extent of reactions involved in in situ combustion and plays a vital role in the viability of the process in light oil reservoirs (Hardy et al., 1972; Burger and Sahuquet, 1972). Effects of rock minerals on the kinetics of combustion were the focus of some recent combustion tube studies (Vossoughi et al., 1982; Fassihi et al., 1984a, b; Hughes et al., 1987). Even though combustion tube experiments achieve the closest approximation to field conditions and provide comprehensive information, the tests are very expensive and time consuming. Consequently, many researchers have used TGA (thermal gravimetric analysis), DTA (differential thermal analysis), and DSC (differential scanning calorimetry) techniques to elucidate certain features of the process and the effects of various variables (Bae, 1977; Yoshiki and Phillips, 1985; Drici and Vossoughi, 1985; Kharrat and Vossoughi, 1985; Jha and Verkoczy, 1986; Phillips et al., 1982; Madden and Maerefat, 1985).

These laboratory studies indicated that the performance of combustion within a given reservoir is dependent on the selection of operating conditions and that the operations must be tailored to the reservoir under consideration. Further, the combustion behavior depends upon the complex interrelationships between kinetics of thermal cracking and low- and high-temperature oxidation reactions. In recent years, there has been increased advocacy for the use of enriched air or oxygen for in situ combustion (Hansel, 1982). It is claimed that the use of enriched air will result in faster oil production, reduced compression costs, and better combustion efficiency and will generate enough CO_2 to decrease the viscosity of the produced oil (Pate, 1985). However, significant oxygen leakage can occur ahead of a combustion front into a steam bank where low-temperature oxidation and other reactions occur with the oil present in this region (Moore, 1988). Further, the enriched air combustion data suggest that the process performs best at lower pressures, and the degree of oxygen enrichment is reservoir specific (Shahani, 1984). Adequate oil mobility is essential for the success of a combustion project. Combustion tube tests revealed stalling and backburning when the thermally upgraded oil failed to displace from the high-temperature region (Moore, 1988).

Multipurpose thermal simulators have also been used extensively to determine the kinetic parameters of the three main reactions involved with in situ combustion: low-temperature oxidation (LTO), high-temperature oxidation (HTO), and high-temperature coking of crude oils in porous media. Good laboratory or experimental data are needed as input to the simulator to predict kinetic parameters reliably. Obviously, inaccurate data will yield incorrect parameters. Further since the actual reaction zones (less than 3 ft) are much smaller than the size of the grid blocks generally used for modeling the process, and the predicted results may be unsatisfactory (Islam et al., 1989).

Current Status of In Situ Combustion Field Projects

Reports on in situ combustion field activities are scarce compared to reports on laboratory research. Reported field activities include both oxygen-enriched combustion pilots (Hvizdos, 1983; Pebdani, 1988); performance review of ongoing combustion projects (Pebdani et al., 1989; Curtis, 1989); and postmortem analysis of terminated projects (Langley, 1985; Farquharson, 1985; Pate, 1988; Choquette, 1991).

Although oxygen enriched air combustion projects generally have resulted in higher oil recovery compared to that of nonenriched-air combustion projects, they have been plagued with more severe safety and operational problems. Some of the safety issues associated with enriched-air (oxygen) combustion projects include: oxygen compatibility with metal, combustion of metals, safe delivery of oxygen to the wellhead, wellbore ignition, and explosions (Hvizdos, 1983). The operational problems associated with enriched-air projects are similar to those encountered in nonenriched-air combustion projects, but are much more severe. These include injection well failure due to tubing leaks, production well failure due to casing collapse, severe corrosion of downhole equipment resulting from combustion products, and production of tight emulsified fluids that are difficult to treat (Pebdani et al., 1988; Langley, 1985).

Postproject analysis of the terminated projects led to the conclusion that it is very difficult to implement an economically justifiable combustion project in geologically complex heavy oil reservoirs, and the recipe for a successful project must include proper coordination of engineering, geoscience and laboratory personnel (Farquharson, 1985). Postcoring results of a Texas oxygen combustion pilot revealed the role of gravity and localized diagenetic hard streaks on combustion sweep (Choquette, 1991). While gravity strongly influences the combustion sweep, shaley streaks have minimal effect. Economic analyses (Pate, 1988; Pebdani et al., 1989) indicated that in situ combustion projects in Texas may be more profitable than those in California because of more favorable economic climate and less stringent environmental constraints. Thus, viability of in situ combustion projects depends on the local economic environment (Pebdani et al., 1989).

One of the oldest and most successful in situ combustion project in the U. S. is the Bellevue In Situ Combustion Project conducted by Getty Oil Company (Long, 1981). Sequential development of the project has permitted the determination of the effect of key variables on oil recovery. Postmortem analysis of project performance revealed that wet combustion process (simultaneous injection of air and water) is superior to dry combustion process followed by water injection to scavenge heat. Details of this project are discussed in Part II of this report. Another DOE-sponsored in situ combustion project in the same field was also technically and commercially successful (Trantham, 1982).

OTHER THERMAL PROCESSES

Electromagnetic Oil Well Stimulation Process

Electromagnetic oil well stimulation is a thermal stimulation process and employs electromagnetic energy as the agent to transfer energy from the surface to the reservoir (Spencer et al., 1988). Fanchi (1990) presented an algorithm for estimating the temperature profile associated with the electromagnetic irradiation of the reservoir. The process is applicable to reservoirs in which an oil is mobile at reservoir conditions and in which sufficient pressure exists to push oil into the wellbore. The process is successfully being field tested in the United States, Canada, and European heavy oil reservoirs.

Thermal EOR Constraints

Major constraints to the more widespread application of thermal EOR are economic and environmental as well as technical. Some of these include:

(a) lower crude oil prices due to gravity, sulfur, and heavy metal content;

(b) large front-end investments and delayed responses;

(c) absence of cost-effective technology to upgrade low-quality, low-gravity crude into salable products; and

(d) absence of cost-effective technology that permits the use of low-grade fuel such as coal, petroleum coke, high sulfur crude oil, and brackish water to generate steam without violating the environmental regulations.

Environmental Constraints

Future TEOR production will be severely constrained in California where the air quality regulations are stricter than the federal counterparts. The San Joaquin Valley, California, where 90% of the U.S. thermal EOR activities are concentrated, is classified as a nonattainment area with respect to ozone and particulates. Further, the immediate vicinity of Kern River is also classified as a nonattainment area with respect to SO_2. Current regulations mandate new thermal EOR operators to use the 'best available control technology' (BACT) on their facility. BACT technology is often costly, and in California BACT requirements vary with districts. This, in many cases, results in the use of BACT that have not been previously tried. Further, new operations are subjected to the 'Prevention of Significant Deterioration' (PSD) review and 'offset' must be obtained for new projects. Obtaining offsets for new projects is the single most difficult and costly aspect of obtaining permits for new facilities (Blevins, 1990).

CONCLUSIONS

Though thermal EOR processes contribute more than 6% of the total U.S. oil production, which constitutes 71% of the U.S. EOR production, the technology is far from being mature, and additional research (listed below) needs to be done.

Additional understanding of basic reservoir properties and geology, refinement of data-gathering instruments, improved steam usage and generation, better well and surface equipment, improved mobility control techniques, and reservoir description techniques must be developed if the large amount of additional oil available from heavy oil reservoirs is to be recovered economically. The short- and long-term research needs are summarized in tables I-18 and I-19.

Table I-18 Near-term research needs

(1) Improved injection profile control techniques

(2) Better define the known mobility-control techniques to improve areal and vertical conformance

Steam foam process

Some issues that need to be addressed include:

- (a) What is the best way to introduce surfactant with steam: slug; semi-continuous; continuous?
- (b) Under what condition do these modes work best?
- (c) Optimum surfactant concentration?
- (d) Effect of rock/fluid properties on steam-foam process?
- (e) Influence of salt on the process?

(3) Improvement in steam quality measurement and control

(4) Development of reliable methods for determining phase splitting at the steam distribution system branches and techniques to ensure a relatively even flow splitting between branches

(5) Development of better techniques of heat management and steam generation

(6) Improved subsurface equipment and completion techniques

(7) Development of methods to treat and/or use brackish water for steam generation

(8) Improvement in horizontal wells completion technique for the high-temperature sanding environment

(9) Development of methods to deplete bypass zones

(10) Development of cost-effective methods to utilize or dispose produced water

(11) Improvement of water-alternating steam process (WASP)

Some problems include:

- (a) What is the optimum slug sizes (water, steam)?
- (b) How effective is the process in improving sweep and recovery efficiency?
- (c) To what extent will the process minimize steam breakthrough severity?

Table I-19 Mid- and long-term research needs

(1)	Development of improved method of reservoir characterization
(2)	Development of techniques to steamflood consolidated sands
(3)	Research on the best way to steamflood light oil reservoirs to maximize recovery
(4)	Development of improved techniques to steamflood fractures and/or dolomite reservoirs
(5)	Development of improved reservoir description tools such as high temperature logging tools, cross hole tomography, etc.
(6)	Development of techniques to steamflood reservoirs with bottom water drive and on gas caps
(7)	Research on high temperature 2- and 3-phase relative permeability measurement involving oil, water and steam
(8)	Development of thermal EOR techniques for recovery of heavy oil from environmentally sensitive areas
(9)	Investigation of the role of high temperature on wettability changes, imbibition effects, andcritical gas saturations on recovery from consolidated formations
(10)	Determination of the effect of high temperature and high pH steam/liquid on rock fluidchemistry
(11)	Development of improved simulation techniques

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CHAPTER 9
DRILLING

By Min K. Tham and Ming-Ming Chang

1. INFILL DRILLING

INTRODUCTION

The use of infill wells to supplement existing wells in waterflooding has been practiced for more than 40 years. Many reports on increasing oil recovery by infill drilling can be found in the literature (Barber et al., 1983; Thomas and Driscoll, 1973). In reducing well spacing through infill drilling, the question of whether only oil production is accelerated or the ultimate recovery can also be increased has been posed since the early part of the history of petroleum industry. The American Petroleum Institute sponsored a study in 1967 (API, 1967) to determine this relationship, but the results were inconclusive. Theoretical groundwork showing the effect of smaller well spacing on ultimate recovery was established in the 1970s (Ghauri et al., 1974; Stiles, 1976; and George and Stiles, 1978). The mechanisms responsible for improving recovery efficiencies for infill wells are: (1) improved reservoir continuity, (2) improved sweep efficiencies (areal and vertical), and (3) recovery of wedge-edge oil (Gould and Sarem, 1989). In 1980, van Everdingen and Kriss (1980) reviewed data from four fields—Slaughter, Levelland, Wasson and Kelly-Snyder SACROC, and concluded that infill drilling with waterflooding would increase the recovery efficiency significantly. Barber et al. (1983) showed, through investigating the performance of nine fields, that the discontinuous nature of the reservoir can be mitigated through the use of infill wells, and the recovery efficiency ranges from 2 to 8% of OOIP. Regression analysis by Wu et al. (1989) using data from waterflood projects showed that reserves can be increased by 8 to 9%.

As in all recovery methods, the technical and economic success of infill drilling will depend on the reservoir characteristics and reservoir heterogeneities. Many of the fields where infill drilling projects were reported in the literature (Barber et al., 1983; Barbe and Schnoebelen, 1987; Gould and Sarem, 1989) were in West Texas carbonate reservoirs (San Andres/Grayburg) belonging to the Open Shelf Platform where reservoir discontinuity is severe. Using Stiles method (1976) and Means San Andres field as an example, Barber et al. found 14% improvement in continuity as the well spacing decreased from 20- to 10-acre spacing, and that continuity calculations made after infill drilling indicated pay zones to be more discontinuous than when calculations were made before infill drilling. Such discontinuity was also observed in Loudon (IL) field (Barber et al., 1983) which belongs to the fluvial dominated deltaic class, the first class of reservoirs to be studied under the Oil Research Program Implementation Plan. In infill drilling in the 20-acre development area, an average initial oil production of 25 bbl/d was obtained while offset wells were producing less than 4 bbl/d. The oil reserves were expected to be increased by 970,000 bbl due probably to an increase in continuity from infill drilling. Such an increase in heterogeneity was observed in going from 0.78-acre spacing to 2.5- and 5-acre spacing in the Loudon surfactant project (Holstein, 1991). Since reservoir characteristics are such an important factor governing the success or failure of an infill project, good reservoir characterization should be performed. For good reservoir characterization, Gould and Sarem (1989) listed geologic studies (map lithologies and depositional models), log analysis, seismic analysis, well tests, and tracers tests as important tools to accomplish this objective (also chapter 10, this report).

In comparing infill drilling and enhanced oil recovery, Holm (1980) proposed to infill drill, waterflood for a few years, and then apply enhanced oil recovery processes. The incremental recovery from infill wells may be sufficient to cover the costs for drilling these wells (Gould and Sarem, 1989). For some reservoirs, one example (Loudon reservoir) was discussed above for fluvial dominated deltaic reservoirs, this approach may be necessary for EOR processes to be successful.

Gould and Sarem (1989) recommended that the U. S. DOE, in association with API or NPC, should form another task force similar to that created for the 1984 EOR evaluation. The charter of this task force would be to determine the potential incremental recovery that could be achieved in the United States by infill drilling

2. HORIZONTAL WELLS

Introduction

Interest in horizontal well drilling and production technology has increased significantly as never before since the 43 wells that were drilled in the USSR in the early 1950s . Horizontal wells were considered uneconomical at that time mainly because of the poor choice of reservoirs used in those experiments (Lang and Jett, 1990). In the late 1970s and early 1980s, Elf Aquitaine continued the experimentation with horizontal drilling (Astier and Jourdan, 1981), and their success sparked the recent boom in drilling of horizontal wells. The number of horizontal wells drilled worldwide increased from 1 well/year from 1978 to 1984, to 28 wells/year in 1986, to 63 wells in 1988 (Moritis, 1989). The 130 wells listed in the second *Oil & Gas Journal* survey (Moritis, 1990) represent only part of all horizontal wells drilled. In a survey of 222 oil and gas companies conducted by Solomon Brothers Inc., horizontal drilling technology is considered to be the most important technological innovation in the petroleum industry in the past 3 years. It is considered to be of equal importance to the introduction of hydraulic fracturing. In the United

States, most horizontal drilling activities are concentrated in the Austin Chalk of Pearsall field (Advanced Recovery Week, 1991a) and the fractured Bakken shale in North Dakota. In Alaska, it is the standard operating procedure for drilling new wells (Oil & Gas Journal, 1991). This increase in horizontal drilling activities can be credited to the rapid advancements in horizontal drilling and completion technologies. These advancements not only allow drilling of longer wells more accurately, but also have reduced drilling costs from 3 to 4 times that of vertical wells to 1.2 to 2 times. Improvement in slim-hole drilling technology is expected to reduce drilling and completion costs by an additional 50 to 60% (U.S. DOE, 1991).

Drilling equipment and techniques for short-turning-radius (20 to 60 ft), medium-turning-radius (300 to 500 ft), and long-turning-radius (600 to 2,000 ft) wells are different (Joshi, 1987a; Nazzal 1990; Bosio et al., 1987). A short-turn radius well is drilled with a build rate from 150° to 300°/100 ft. Horizontal sections of up to 1,000 ft have been drilled. The two drilling systems used are the mechanical or rotary system that uses a curved drill guide and the articulated motor assembly system. The motor assembly can be monitored constantly with a bottomhole assembly, and no additional trips for hole surveys are needed as in the mechanical system (Trichel and Ohanian, 1990). A medium-turning-radius well is usually drilled with a special motor that delivers low speed and high torque output to the bit. The build rate ranges from 8° to 20°/100 ft, and hole sizes of up to 12 1/4 in. are drilled. Fixed-angle, adjustable-angle, double-adjustable-angle built motors, and steerable motors with measurement-while-drilling (MWD) surveying have been used. Medium-turn-radius technology allows flexible build rate and well profile; it is, therefore, the most common method of drilling (Nazzal, 1990). A long-turning-radius well has a build rate of 2° to 6°/100 ft and is drilled with conventional drilling equipment. To kick off and initiate angle, either steerable motors or slick motors with bent subs are used. Steerable motors controlled by MWD methods are the preferred method of drilling. There is no limitation on the hole size for long-turn-radius horizontal wells, and the horizontal part of the well can be as long as 5,000 ft. Completion technology for long horizontal wells is said to be lagging the drilling technology by a few years (Lang and Jett, 1990); however, completion technologies are catching up to most traditional completion methods: open-hole, zone-isolation (packers), slotted-liners, cementing, and perforating and gravel packing completion methods are now being used in horizontal wells (White, 1990; Matson and Bennett, 1990; Spreux et al., 1988a; White, 1990). The type of completion used is dictated by the turning angle, degree of consolidation of the rock, type of heterogeneities (faults, fractures, etc.) that require zone isolation, and anticipated workover and stimulation needs. Slotted-liner completion is the most common method of completing these wells although cementing and perforating are also practiced. Logging, coring, and stimulation of horizontal wells have been performed (Blanco, 1990; Spreux et al., 1988a; Spreux et al., 1988b; Moritis, 1990; Sabins, 1990). Of the 130 wells listed in the 1990 *Oil & Gas Journal* survey, only 8 were cored, whereas 11 wells were hydraulically fractured. Multiple hydraulic fracturing in horizontal wells has also been applied in the field (White, 1989).

Geology in Horizontal Drilling

For horizontal wells to be competitive with vertical wells economically, horizontal well sites must be chosen judiciously. The early drilling experiments in the USSR were considered uneconomical because of the poor choice of test sites, and the suitability of production methods for the reservoirs was not considered (Bosio and Reiss, 1987). In current practice, horizontal wells are used primarily to increase production rapidly by exposing additional volumes of reservoirs to wellbores and also to increase recoverable reserves. The applications of horizontal wells include producing thin hydrocarbon reservoirs, producing low-permeability reservoirs, connecting vertical fractures, controlling water and gas coning by increasing the critical production, controlling sand production (by reducing flow rate at the sand face), increasing productivity from gravity drainage, and increasing injectivity (Montigny and Combe, 1987; Moritis, 1990).

A thorough knowledge of the geology of the reservoir is most important in selecting a horizontal well drilling site whether the purpose of the horizontal well is to connect fractures, to alleviate gas or water coning, or to increase production in a thin or low-permeability reservoir (Montigny and Combe, 1987). Horizontal drilling is also a good candidate for producing reservoirs where compartmentalization is preventing efficient production. Point bar formations in fluvial-deltaic depositional environment (one of the EOR Class I depositional environments) are an example where compartmentalization by the lateral accretional bodies can prevent efficient oil production (Xue, 1986). A horizontal well penetrating several of these compartments has the potential to alleviate this production problem.

A horizontal well can penetrate a considerable length of a reservoir and can, therefore, provide an excellent opportunity to evaluate a formation (Taylor and Eaton, 1990; Crane and Tubman, 1990). Computerized mud logging, formation evaluation measurement-while-drilling (FE-MWD), coring, and logging of a formation could provide information for characterizing micro-, macro-, and megascale heterogeneities (Sheikholeslami et al. , 1989). Overbey et al. (1989) used a borehole video camera to study the natural fractures in a horizontal well drilled in the Devonian Shales. The fracture pattern and orientations were documented, and two-phase flow phenomenon was also observed.

The economics of reentering existing wells, particularly the strippers scattered throughout the United States, are unfavorable at current oil prices. The expense associated with drilling into a well producing 10 bbl/d of oil in hopes of doubling output greatly limits economic opportunities. This is one area, however, that is under investigation. For example, in the Texas Panhandle, horizontal drilling has been used to enhance production from marginal vertical wells (Slayton, 1990).

Reservoir Engineering Aspects of Horizontal Wells

The principal difference in reservoir engineering analysis of horizontal wells as compared to that of vertical wells is in the geometry of the drainage volume. The drainage volume of a horizontal well (before the reservoir boundary is reached) is an ellipsoid, whereas that of a vertical well is cylindrical (radial flow). Another important difference is that in most cases, the ratio of the vertical to horizontal permeabilities in a reservoir is different from 1 (usually <<1). This ratio can affect the streamlines around a horizontal well tremendously. The increase of productivity of horizontal wells over that of conventional vertical wells is one major reason that makes horizontal well drilling popular today. Various reservoir engineering analyses can be made to analyze and to predict the performance of a horizontal well . Many analytical formulas and numerical simulators have been developed for calculating the productivity for horizontal wells under various reservoir and production conditions. These include production calculations using analytical formulas for steady state or transient production estimation methods and reservoir simulation using mathematical models with various degree of sophistications. A recent paper (Norris et al., 1991) reviewed the reservoir engineering aspects of horizontal well production technology.

Analytical Productivity Formulas

Several analytical formulas for predicting horizontal well productivity have been developed in recent years. Analytical formulas have the advantage that the calculations can be easily performed, but in developing these formulas, a number of assumptions were made. These assumptions restrict the applicability of these formulas to single-well production in a homogeneous reservoir, neglecting the effects of gravitational forces. In these formulas, the effects of pressure on rock and fluid properties are neglected. The wellbore location is assumed to be in the central part of the reservoir in most analytical formulas.

The characteristics of analytical productivity formulas for horizontal wells are listed in table I-20. According to the stage of production, the analytical formulas can be divided into two groups: steady state and transient state.

TABLE I-20. - Characteristics of analytical productivity formulas

PI formula from	Production state	P_e solution[1]	Mathematical	Other characteristics
Joshi (1986) Giger (1984) Borisov(1964)	Steady state at boundary	Pressure approximation in drainage area	Mathematical well, (Joshi, 1986) accounted eccentricity	Centrally located well.
Babu(1989) Kuchuk (1988) Mutalik (1988))	Pseudo-steady state	Average reservoir pressure	Line source solution	Bounded reservoir Well may not be centrally located.
Clonts(1986) Ozkan (1987)	Transient	Initial reservoir pressure	Line source solution Eccentricity accounted	Infinite reservoir, centrally located well.
PID formula from well model	Steady/pseudo-steady/transient	Well block pressure	Couple radial flow in well block to neighboring block	Wellbore fully penetrated well block.

[1] P_e = Pressure drawdown + (flowing bottomhole pressure).

Steady State Productivity

Borisov (1964), Giger (1984), and Joshi (1986) developed formulas for calculating productivity of horizontal wells under steady-state conditions. All these formulas assumed a single-phase flow from a centrally located horizontal well in a rectangular, bounded drainage area. These three formulas agree within 15% of each other on horizontal well productivity from a sample case calculation. Because of its easy application, the steady-state analytical formula is often used to provide a preliminary estimation of a horizontal well's productivity at the design stage. Applying Giger's formula to calculate the productivities of wells Lacq 90 (Lacq Superieur field in southwestern France), and Castera Lou 110 (Castera Lou field in southwestern France), Reiss (1987) found that the predicted productivities were in reasonable agreement with the field production data. Applying Giger's formula to a well in Prudhoe Bay, Sherrard et al. (1987) failed to achieve good agreement with field data. They attributed this lack of agreement to formation damage although poor vertical reservoir continuity could also have been the cause. On the other hand, Renard and Dupuy (1990) and Peterson and Holditch (1990) considered the effect of formation damage to be less pronounced in horizontal wells than in vertical wells.

Transient Pressure State

Several authors (Clonts and Ramey, 1986; Ozkan et al., 1987; Daviu et al., 1985) have developed essentially the same pressure transient relationships for a horizontal well located in an infinite volume reservoir. Carvalho and Rosa (1988) and Aquilera et al. (1989) developed mathematical formulas to describe the transient pressure behavior for horizontal wells in naturally fractured formations. In addition to estimation of well productivity, transient pressure tests are used to calculate formation permeabilities and skin factors around horizontal wells. Sherrad et al. (1987) and Kuchuk et al. (1988) presented successful analyses of transient pressure tests of horizontal wells in Alaska.

Assumptions used in vertical well tests were applied for solving the diffusivity equation for the transient pressure of a horizontal well. These assumptions are: negligible gravity effects, a homogeneous porous medium, a single fluid of small and constant compressibility, and applicability of Darcy's law. The major difference in horizontal well tests from vertical well tests is that both horizontal and vertical flows around the wellbore are considered. The vertical pressure gradients at the upper and lower formation boundaries are taken to be zero.

For solving the diffusivity equation, the horizontal well was modeled as a uniform flux line source located between and parallel to the impermeable strata. The system is infinite in x- and y-direction and the instantaneous source functions derived for the vertical well case in the x- and y-direction were used for the horizontal well case. The instantaneous point source function in the z-direction can be generated using the method of images. Finally, by applying Newman's product principle, the instantaneous point source solution for horizontal was integrated over the well length, and the pressure drawdown equation was derived.

Odeh and Babu (1990) derived equations for pressure drawdown and buildup analysis for a reservoir with closed drainage volume. Formation anisotropy was taken into account. Their equations were applied in the analysis of the transient tests in the Bakken formation (Williams and Kikani, 1990).

Numerical Horizontal Well Simulator

Because of their oversimplifying assumptions, analytical formulas present difficulties in predicting the production of horizontal wells from reservoirs with permeability heterogeneity, multiple well production, and irregular reservoir shape. Reservoir simulators incorporating the horizontal well model (Chang et al., 1989) are capable of overcoming these problems. A numerical simulator can consider combinations of various well patterns and geometries and account for reservoir heterogeneity, gravity force, capillary pressure, and variation in rock/fluid properties. Its disadvantages include high cost of running and the requirement of expensive hardware and experienced reservoir engineers to run the simulator and to interpret the results. Oryx Energy Co. found that only a numerical simulator can interpret the horizontal well production from its fractured chalk formation in Pearsall (TX) field (Schnerk et al., 1990). A mathematical simulator is also required for predicting production of horizontal wells from a reservoir with bottom aquifer or gas cap. Simulation runs performed by 14 organizations were compared (Nghiem, et al., 1991) on a problem involving production from a horizontal well in a reservoir where coning tendencies are important. All participants consistently predicted a decrease in the coning behavior with an increase in well length.

Pressure Drop in Horizontal Well

A horizontal wellbore may be as long as 5,000 ft, and the pressure drop experienced by fluid flow through the wellbore could be significant and cannot be neglected for accurate estimation of reservoir performance. Dikken (1990) developed a method for determining the pressure drop in single-phase, turbulent flow. In multiphase flow, the pressure drop is a strong function of the proportion of each phase, and the flow regime. The pressure drop during segregated flow will be different from slug flow. Carlson and Davarzani (1990) in an experimental program showed that at a flow rate below 1,000 bbl/d, segregated flow predominates for 4-in. ID pipe. Through physical and mathematical modeling, Islam and Chakma (1990) developed equations for bubble-induced turbulence and jet-like flow through perforation in two-phase (gas-oil) flow; fair agreement between experimental and predicted results was observed.

Enhanced Oil Recovery

EOR projects can also be improved by using horizontal injectors or producers. Horizontal wells increase injectivity and also improve sweep efficiency by contacting a large volume of the reservoir by altering the flow streamlines. Horizontal wells have been proposed for use with steamflooding, polymer flooding, and gas miscible flooding projects.

Using a scaled model, Huygen and Black (1982) showed that steamflooding in horizontal wells in combination with vertical wells would efficiently recover heavy bitumen. The effect of vertical fractures was also studied. Joshi (1986) studied steam-assisted gravity drainage in an unscaled laboratory model. This recovery method has the potential of reducing gravity override and steam channeling since high pressure is not used to drive the mobilized oil (Joshi, 1987b). High sweep and thermal efficiencies for this production scheme were demonstrated in his experiments.

In numerical simulation studies of steamflooding with horizontal wells, recovery efficiencies as high as 67.8 to 75% were reported (Rial, 1984; Huang and Hight, 1989). Steam override can be alleviated using horizontal wells; the response time to steam, and conformance can also be improved. Improvement in recovery using horizontal wells has been shown to be strongly dependent on well length and lateral extent of the reservoir, and maximum sweep efficiency has been obtained when injector and producer were placed far apart (Folefac and Archer, 1987).

Horizontal wells can also be used to extend the range of economic applications of steamflooding to thin, viscous oil reservoirs (Petit et al., 1989). Simulation studies also have shown that sweep efficiency in miscible floods can be improved using horizontal wells (Chen and Olynyk, 1985). This improvement was attributed to an increase in productivity index and reduction in viscous fingering. In an experimental study, Ammer et al. (1991) showed that horizontal injection wells significantly increased oil recovery over that of vertical injection wells. Good matches between predictions using a compositional/incomplete mixing simulator and experimental results were achieved in this work. Chen and Olynyk also found sweep efficiency improvement using a combination of vertical and horizontal wells in miscible flooding over vertical injection production wells, which was a departure from the findings in simulation of a steamflooding process (Rial, 1984).

A hot oil process (HOP) was used to recover heavy oil (18° to 20° API) in Kern River (CA) field. The HOP method consisted of drilling eight lateral wells from a 30-ft-high by 25-ft-diameter chamber at a depth of 500 ft. These lateral wells were used as producers; steam was injected from vertical wells situated above these laterals (Albayrak and Protopapas, 1984). After recovering 2.5% of the oil in place, the pilot was terminated because of unfavorable economics (Dietrich, 1988). Reservoir conditions (stratification from tight claystone) at the pilot site were unfavorable for the application of this novel technology and were cited as the cause for the poor early recovery.

The application of horizontal wells in the Underground Test Facility by Alberta Oil Sands Technology and Research Authority (AOSTRA) is a project combining steamflood with horizontal drilling technologies (Best et al., 1985). In 1989, six wells were drilled to recover the oil that has a viscosity of 1 million cP at 50° F. Steam is injected to recover the oil. The results from this small-scale pilot are considered excellent, and six more wells were planned for 1990 (Moritis, 1990).

A horizontal well was drilled in Chateaurenard field to intercept the oil bank from a polymer flood pilot in progress (Bruckert, 1989). Reduction in water cut was observed after producing the horizontal well for about 1.5 years. The ability to overcome problems with horizontal permeability anisotropies and the high productivity of the well combined to make this well the best producer in the field.

RECOMMENDATIONS

Infill drilling, whether using vertical or horizontal wells, has the potential of increasing the reserves of domestic reservoirs. Recent advances in horizontal well drilling and reservoir engineering technologies have increased this potential even further by reducing costs of drilling and the improved predictability of oil production. Drilling and service companies are making extensive efforts to advance the technology further. In essence, the petroleum industry has been identifying constraints and is solving these problems. There is little or no need for DOE to fund research in these areas. The potential of applying horizontal wells to improve EOR recovery efficiency needs to be investigated further. For infill drilling to be economical and successful in increasing reserves, the production characteristics of the reservoir need to be clearly defined. At present, no general criteria for selecting reservoirs for successful infill drilling have been developed, and each reservoir must be characterized and analyzed individually, this is another area that needs further research.

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CHAPTER 10

RESERVOIR CHARACTERIZATION -- STATE OF THE ART REVIEW

By Susan R. Jackson and Liviu Tomutsa

INTRODUCTION

A review of EOR field projects (Part II, this report) reveals that about 30% of the total identified constraints can be classified under the broad category of reservoir heterogeneity and the related constraint—mobility control. Both constraints affect sweep efficiency. In recent years, the importance of reservoir characterization has been appreciated, and significant advances have been made both in reservoir characterization techniques and the approach to reservoir characterization.

The primary purpose of reservoir characterization is to account for reservoir heterogeneity through a synthesis of reservoir description as a basis for reservoir simulation. The spatial distribution of reservoir characteristics must be (1) predicted in the interwell region where data are lacking and (2) represented in such a way that numerical input for a simulator retains the information critical to fluid flow within the context of the recovery process being studied. Thus, reservoir characterization provides a link between the static and the dynamic components of a reservoir model.

Reservoir characterization requires the integration, reconciliation, and distillation of (1) information from various sources and disciplines and (2) information of various scales, into a physically equivalent, unified reservoir model. The end products of reservoir characterization are reservoir simulation models that allow the prediction of fluid flow dynamics within a reservoir and provide information for reservoir management decisions such as performance predictions, optimum recovery techniques, risk, cost, and benefit of reservoir management alternatives.

The development of a reservoir management strategy for a field is an iterative process and should begin at the time of the discovery well (figure I-6). This strategy will prevent the repetition of mistakes of the past where planning for EOR begins only after the field has reached residual saturation, and the option of applying EOR processes becomes less attractive. As more static and dynamic reservoir information is acquired, the management strategy will be adjusted or changed accordingly. Systematic collection of multidisciplinary data important for the design of future recovery processes must begin early in the life of a reservoir. Early collection of data that requires unaltered, natural- state reservoir conditions such as reservoir pressure, wettability and

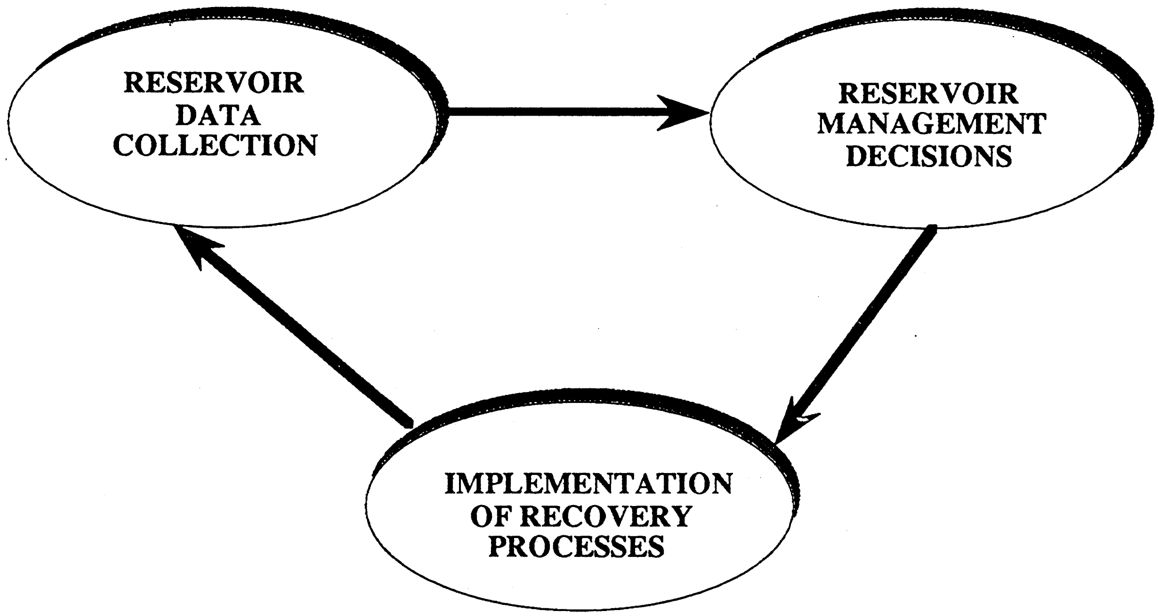

FIGURE I-6. Schematic showing iterative process of reservoir management and data collection.

brine chemistry is especially important for EOR process design and is often neglected. Reservoir characterization essentially dictates the EOR strategy (Venuto, 1989), and must be an integral part of EOR planning and design.

Advances in the approach to reservoir characterization are the realization that reservoir description requires information from various disciplines and that recovery process design (e.g. waterflooding, gas displacement, steam injection, chemical flooding or microbial treatments) must be in concert with the reservoir description. Therefore, a multidisciplinary team composed of geologists, engineers, geophysicists, log analysts, petrophysicists, and chemists has to work in a synergistic approach with a well defined mission on each reservoir characterization project (Raza, 1990). These scientists and engineers must work interactively (Needham, 1991) throughout the entire project period, applying an integrated approach (Jackson et al., 1991) for the project to be successful.

Advances have been made in the areas of (1) improvement in resolution for measuring reservoir properties such as imaging, logging, seismic and well testing techniques; (2) the quantification of geological features such as facies dimensions and reservoir heterogeneities; (3) analytical tools in geostatistics including conditional simulation and fractal analysis; (4) the ability to construct and simulate more detailed and accurate reservoir models; and (5) the application of engineering analysis to quantify heterogeneities between wells. These advances provide an increase in the quantity and quality of reservoir information and significantly contribute to our capability to predict fluid flow in the interwell region.

The constraints in reservoir characterization are due to (1) the complexity of the rock and fluid distributions in even the "simplest" reservoirs and (2) the inadequate amount of detailed information from even the most ambitiously sampled reservoir. The challenges in reservoir characterization include (1) obtaining sufficient detailed reservoir information; (2) constructing predictive models of spatial distribution of reservoir characteristics in the interwell area; (3) incorporating the abundant semi-quantitative information available from the reservoir into simulation models; and (4) developing scaling or averaging procedures for determining representative simulator grid block values.

PROCESSES OF RESERVOIR CHARACTERIZATION

Team Formation and Management

An integrated, multidisciplinary team is an essential component to effective reservoir characterization. The team must be assembled to evaluate the reservoir data needed for successful implementation of the various recovery strategies. This team has to have expertise in the geological and engineering areas of reservoir characterization as well as the enhanced recovery processes considered.

The three requirements for an integrated approach to reservoir characterization identified by a group of scientists at the Second International Reservoir Characterization Conference in Dallas, TX (Lake, et al., 1991) are as follows:

1. Identify and clearly define objectives. These objectives must be based on the current understanding of the reservoir and the existing and predicted economic conditions. The amounts and kinds of data necessary to achieve the objectives must be established.

2. Create and maintain flexible team organization and management. A flexible group structure is necessary to maintain adaptability to changing economic and management objectives. The leader should be a working member of the team and a core group of individuals should be maintained at all times for continuity, even though some individuals may move into and out of the group. Frequent, informal meetings among team members should occur, and regular meetings with management should be scheduled.

3. Develop a computer-based database management system. The data format should allow data from all disciplines and at all scales to be easily incorporated and a wide variety of end-user

products should be available so that data from several disciplines and scales can be compiled and used in application software.

The initial investment in manpower and resources required to create and maintain an integrated reservoir characterization team is one of the main constraints in reservoir characterization. While even major oil companies may have difficulty in freeing in-house resources to assemble such multidisciplinary teams, medium and small companies most likely lack the extra personnel and financial resources necessary, since existing personnel are typically fully occupied with day-to-day operations.

Personnel and financial constraints can be addressed by the Department of Energy as part of the near-term strategy by providing grant assistance on a competitive cost-shared basis to small and medium sized producers who have significant production potential. The grants would be used specifically to pay for expert help to accomplish this first phase of mission definition. The immediate product will be a number of increasing production scenarios, with the reservoir characterization requirements and a cost/benefit analysis for each scenario.

Methodology for Reservoir Characterization

A methodology that lays out a systematic approach for reservoir characterization must include a large number of steps. However, the major activities that must be addressed in a reservoir characterization scheme are indicated in figure I-7 and include (1) data collection, organization, evaluation and integration; (2) reservoir model construction and simulation; and (3) reservoir evaluation. Basic sources of information are core descriptions, well logs, core analyses, reservoir fluid analyses, well tests, production/injection performance, reservoir performance, and information from analogous reservoirs, outcrops, and modern deposits.

A major constraint in reservoir characterization is that few comprehensive methodologies are presented in the petroleum-related literature. Current practice often does not employ systematic data collection based on a clear development strategy, but rather data are obtained in a random fashion at the time operational decisions are made. Data quality assurance is often inadequate, and problems of consistency of measurements and reconciliation of data from various sources are largely ignored. Vast amounts of information available from cores, analogous outcrops, reservoir and well performance histories, and injection/production data are not used. All too often appropriate scale-up procedures are not applied and large quantities of "soft" geologic data are not incorporated into simulation models (Honarpour et al., 1990).

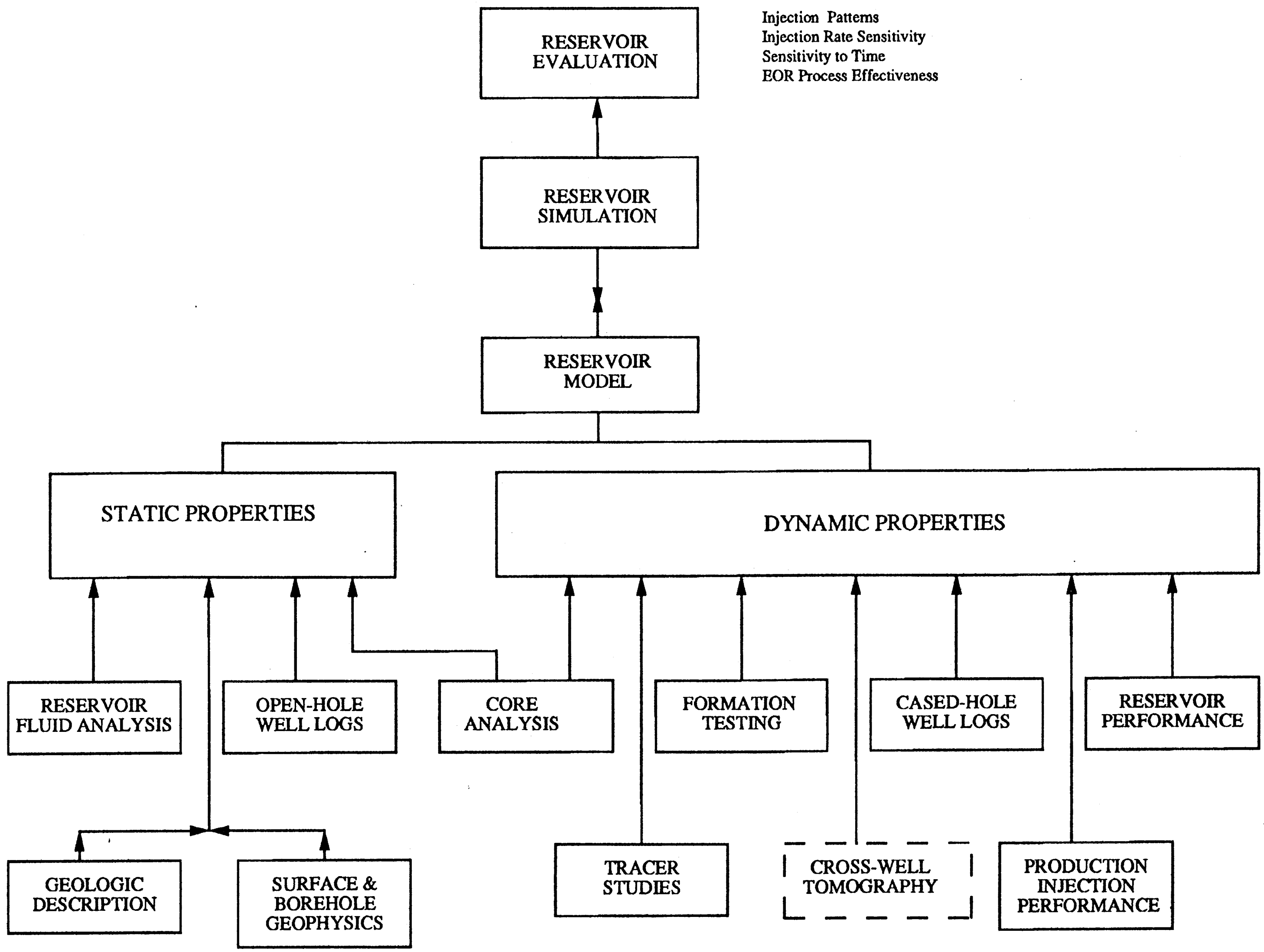

Figure I-7. - Scheme of reservoir characterization and evaluation. (Modified from P. F. Worthington, 1991.)

Data Collection

The major constraints of abundant data collection are the manpower and hardware costs to generate computerized data bases from disaggregated hard copies. Although integrated, commercial data bases are available, they do not contain the detailed, field-specific information required for reservoir characterization. New technologies of scanning devices and desktop application workstations provide an excellent platform from which to create a data base.

As the data acquired have to answer different questions at different stages in reservoir production, a data acquisition plan needs to be developed as early as possible in the life of a field. The advantage of having a long-term data-gathering plan is that one can start acquiring, storing, and analyzing the data for secondary and tertiary recoveries during primary recovery and performing additional data acquisition and analysis for tertiary recovery during secondary recovery. In anticipation of application of recovery processes in the future, regardless of whether the recovery process is waterflooding, gas displacement, steam injection, chemical flooding or microbial treatments, reservoir and fluid parameters that can impact the recovery efficiency and process design should be collected as the field is being developed.

Data at various scales are necessary for reservoir model construction: from microscopic data obtained from analysis of thin sections and core plugs that explain the pore level oil trapping mechanisms, to near-well, interwell, and field-scale data obtained from logs, interference and pulse testing, and seismic data acquisition which explains on an increasingly large scale the factors controlling fluid movements and trapping. The relative emphasis on various scales in data acquisition depends on the reservoir geology, the stage of reservoir development, and the process being considered. The system of data acquisition should allow the early derivation of a depositional model of the reservoir, which will be used as a guide for further data acquisition and will be refined and modified as necessary.

Throughout field development, the sampling has to be representative of the reservoir rock and the data at various scales should be reconciled and integrated, allowing the high-resolution data at smaller scale to calibrate the larger-scale data (Worthington,1991). Use of new nondestructive core characterization techniques such as X-ray computed tomography, and minipermeameter permeability measurements can provide accurate and detailed data for rock characterization at small scale in a rapid and economic fashion. At even a smaller scale, computer-aided petrographic image analysis of thin sections can increase speed and accuracy in generating petrophysical parameters from thin sections of plugs or drill cuttings.

One of the constraints in interscale integration is the need for understanding the range of applicability and limitations of various methods (core, log, pressure testing, seismic) used in reservoir characterization (Figure I-8). Applying these techniques presents a major financial and personnel commitment as well as possible disruptions in daily field operations. These financial and personnel constraints have to be addressed by the reservoir characterization team early in the planning of the data-acquisition strategy when cost/benefit analyses for various scenarios should be performed. The cost-benefit analysis should include the magnitude of uncertainty in reservoir engineering estimates of static data (bulk volume, porosity, saturation, etc.) that determine hydrocarbon-in-place estimates, and the dynamic data (flow barriers, permeability, relative permeability, etc.) that influence dynamic behavior (Ovreberg et al., 1990). Costs of reservoir characterization can be reduced by formulating well defined questions, specific to the reservoir and the recovery processes considered and the use of techniques specifically targeted to yield the required answers. As data acquisition is an iterative process, time and manpower should be planned for answering questions which arise after reservoir characterization has begun.

For older reservoirs, reanalysis of existing data (seismic, core, log, injection/production, etc.) in a synergistic way, can provide a highly cost-effective approach to reservoir characterization (Honarpour et al., 1988). By storing the data in versatile databases and using the latest 2-D and 3-D graphics display technology (Fried, 1990), correlations between data can be explored rapidly; maps, cross sections and 3-D models of the reservoir can be generated; and discrepancies between different data found and improved. The use of this technology in data analysis enhances the effectiveness of reservoir characterization team members and improves communication. Further improvements in the "user friendliness" of software coupled with an "expert systems" approach will help increase the efficiency of using software in solving reservoir characterization problems.

Estimates of the size of oil reserves may require expensive methods to measure reservoir oil saturations (Chang et al., 1988). However, lower cost methods based on comparison of simulation and field data (Honarpour et al., 1988), resistivity versus effective porosity crossplots or the differential oil-in-place (Cheng and Sharma, 1991) can also be used to understand the remaining oil distribution.

Model Construction

Although the reservoirs are by nature deterministic, in that only one actual realization exists, by necessity the outcome of the data-acquisition stage is a set of data of statistical nature. This is due to the inability to completely sample a reservoir due to economic or technological constraints. This set of data has to be analyzed in a timely and cost-effective manner to achieve the goal of

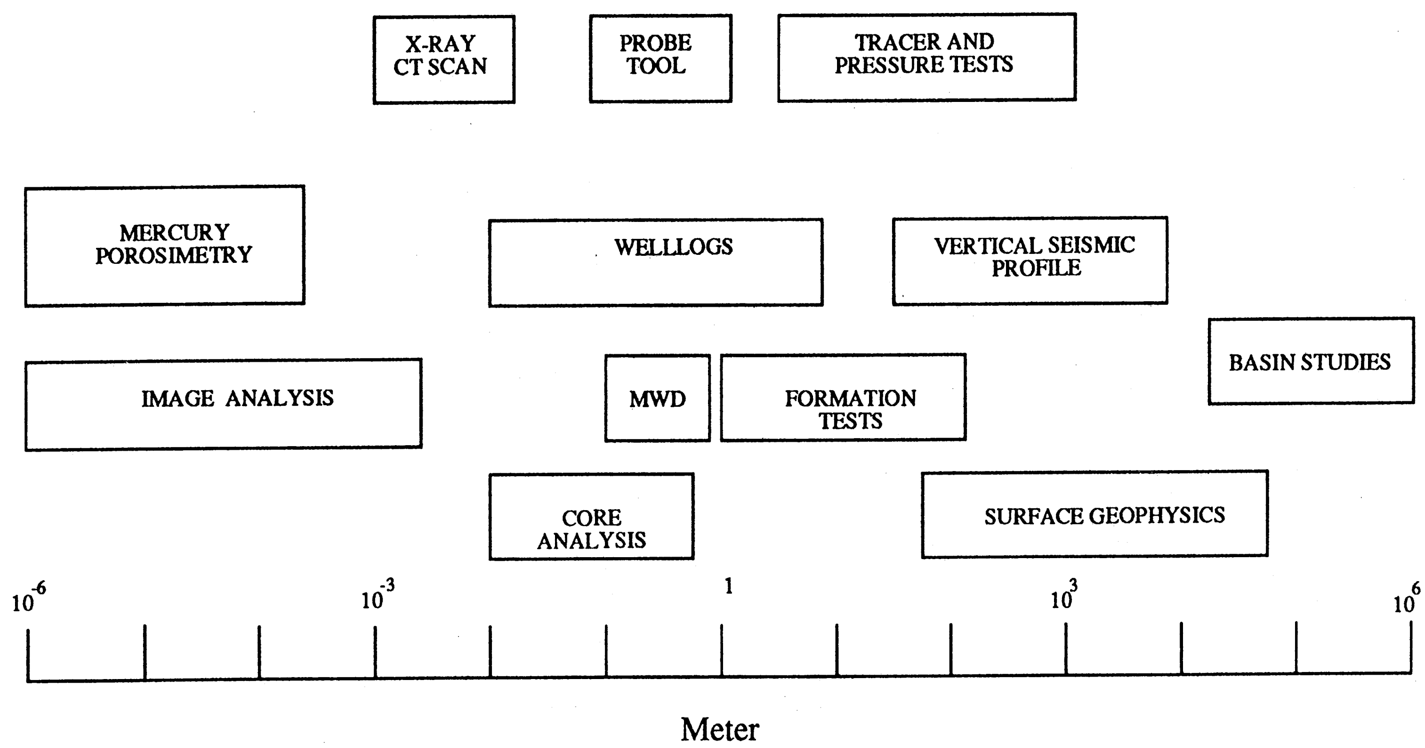

FIGURE I-8. - Scales of measurement expressed in terms of resolution (after Worthington, 1991).

reservoir characterization which is to generate the most likely models compatible with the existing reservoir data. The models should reflect both the deterministic and the statistical nature of the data and be compatible with the geological understanding of the reservoirs. In spite of the uniqueness of each reservoir, general characteristics can be used in model building. For example, most clastic reservoirs can be classified in three classes: from the single layer cake model to jig-saw puzzle to labyrinth, reflecting the increased reservoir complexity and correspondingly the increased need for a statistical approach to the modeling (Weber and Van Geuns, 1989).

The layer cake reservoir types have layers representing sands deposited in the same depositional environment, and the logs show excellent lateral correlations between wells located as far as 3,000 ft apart. Such models are deterministic, and they represent depositional environments such as shallow marine, offshore bars, and aeolian deposits. In such reservoirs, one should still identify major interwell barriers to flow due to faults.

The jig-saw puzzle reservoir types have a more complex architecture of sandbodies fitting together and require wells at closer spacing (2,000 ft) for correlating the main sandbodies. If data exist on such a scale or smaller, deterministic models are possible, otherwise, a stochastic approach is needed to describe the reservoir. These models can be used in representing reservoirs such as those containing point bars or turbidite fans.

The labyrinth reservoir type has the most complex arrangements of sand pods and lenses often separated by impermeable nonreservoir rock and, unless wells are spaced at distances below 1,000 ft., deterministic correlations between the sandbodies are not possible. The stochastic approach is appropriate for describing these reservoirs. These reservoirs are often composed of many channel fill bodies arranged in a labyrinth fashion.

Geostatistical analysis techniques allow the characterization of both the deterministic and the statistical spatial characteristics variability of the data (Journel and Huijbregts, 1978). They can also be used to perform risk analysis for reservoir management.

Stochastic modeling uses information geostatistical analysis to create reservoir models compatible with the input data. Significant experience has been accumulated in the past 5 years with the application of a variety of mathematically sophisticated stochastic techniques to generate reservoir models (Haldorsen and Damsleth, 1990). Existing stochastic techniques can be classified as (a) discrete techniques, such as marked point processes, Markov fields, truncated random functions, two point histograms and (b) continuous techniques, such as indicator kriging, Gaussian random fields, and fractal fields.

The discrete models can be used to generate models of random shale distributions in sandstone reservoirs (Haldorsen and Lake, 1982; Haldorsen and Chang, 1985), dimensions and locations of fluvial sandbodies (Fogg, 1986), and facies and permeability distributions in fluvial deltaic reservoirs (Guerillot et al., 1989).

Continuous stochastic techniques allow the generation of continuous parameters such as porosity and permeability distributions. Kriging has been used relatively often to generate interpolated values for mapping reservoir parameters such as net pay, porosity or permeability, at the same time generating a map of the variances. A limitation of the kriging method is that it smooths out the spatial variations that exist in the reservoir and cannot effectively combine data with different degrees of accuracy. A more powerful tool is the recently developed indicator kriging (Journel and Alabert, 1990) which allows the incorporation of widely different data types ranging from "hard" data, such as measured core porosities, to "soft" data, such as estimates of probability ranges for the rock type, to generate highly realistic stochastic reservoir models.

Another approach which recently has been used successfully to characterize heterogeneity in reservoirs is based on the fractal behavior of certain reservoir parameters (Hewett and Behrens, 1988, Tang et al., 1989). Two dimensional, vertical conditional simulations of the reservoir heterogeneities are performed, using the fractal dimension calculated from logs. The results of these simulations are used in areal streamtube simulation to predict the reservoir performance.

By combining stochastic modeling with advanced imaging techniques many realizations of the reservoir, all compatible with the existing reservoir data, can be displayed. Thus one can see if the variability of critical features from one realization to the other (such as random barriers or thief zones) is within the set tolerance limits. If they exceed this limit, new data are required to reduce the uncertainty in predicting such features.

The constraints in using the stochastic modeling approach are the scarcity of input data (especially regarding the lateral correlation distances and appropriate location of control points), the large variance in the model outputs and their computer intensiveness, and the high mathematical skill required to take full advantage of their capability. Although significant progress has been made in recent years in using outcrop data together with reservoir data for input into stochastic simulators, the need remains to expand this area of research to various types of representative reservoirs. By improving the operator interface, especially by adding "expert system" features to help in the usage of the model and interpretation of results, the learning time for model usage can be shortened. Computer intensiveness is becoming less of a problem as advances in technology increase both the speed and the memory capacity of available computers.

DATA SOURCES

Reservoir Data

The two basic sources of data for reservoir characterization are data from specific reservoirs and data from analogue reservoirs, outcrops, and modern environments. Reservoir data can be broadly divided into two categories: (1) rock properties (the container) and (2) fluid properties (the contents). Although most reservoir characterization efforts have been applied to the characterization of rock properties, fluid characteristics, the heterogeneity of reservoir fluid chemistry and rock/fluid interaction (e.g wettability and ion exchange capacity) are essential to the development of accurate reservoir models.

Reservoir characterization utilizes data on range of scales from basin and field-scale information (km) to pore-size information (microns). Field-scale information establishes the spatial framework and the general architecture of the reservoir for describing and predicting smaller scale reservoir geometries and heterogeneities, along with their associated petrophysical and fluid-flow properties. Examples of the types of information obtained from field-scale description are (1) compartmentalization of the reservoir into more than one producing zone or unit; (2) the position, geometry, and connectivity of the facies or reservoir units; (3) the evaluation of the spatial distribution of lithologic heterogeneities that comprise barriers, baffles, and high-permeability "thief" zones; and (4) the relationship of the lithologic units to hydraulic units so that the fluid-flow pathways can be identified.

Mesoscopic-scale information looks at the variations of properties within the facies or reservoir units. Core-log calibrations are used (1) to establish the representativeness and compatibility of the measured parameters, (2) to integrate downhole measurements with data from pore studies, core analysis, and geophysical surveys through interscale reconciliation; (3) to identify reservoir units that contain similar petrophysical properties; and (4) to relate and reconcile petrophysical interpretations with geochemical, sedimentological, stratigraphic, and structural information.

Microscopic or pore-scale information that affects fluid flow in reservoir rocks includes pore-size, pore throat, surface roughness, grainsize, and sorting. The major controls on these features are the sediment source (provenance) and the subsequent diagenetic processes of compaction, cementation, and dissolution.

Petrography

The consequent features of diagenetic processes influence drilling, completion, stimulation applications, log analysis, and injection-fluid/rock interactions as well as pore geometries and pore-throat types and must be taken into account for each stage of production.

The current capability to predict the types, spatial distribution and effects of diagenetic products is sorely lacking. There are numerous well-known techniques available for describing the diagenetic phases found within reservoir rocks (e.g. scanning electron microscopy, X-ray diffraction, electron microprobe microanalysis and vitrinite reflectance), and analytical techniques for analyzing reservoir fluids (e.g. gas chromatography, mass spectrometric analysis), and ratios of various organic fractions (e.g. pristane/phytane ratios). However, there are a number of other techniques that are less well known, and whose utility is less well understood. These include fluorescence microscopy, cathodoluminescence, fluid inclusion analysis, atomic absorption, and stable and radiogenic isotope analysis for mineral samples.

Future needs for research defining the effects of diagenesis on reservoir characterization must be oriented toward interpretation of multiple, diverse analytical techniques that can be integrated into predictive diagenetic models on different scales. Particular emphasis on using integrated diagenetic models is needed to predict the spatial distribution of diagenetic phases within specific reservoir strata, on the interwell to field scale. Such predictive diagenetic models will probably require process-based, basin-wide precursor studies to provide basic regional information about diagenetic cycling, recharge and fluid flow, heat flow, subsidence rates, open versus. closed systems, tectonic complications, basic mineralogy and rock-water interactions. The key to understanding the importance of diagenesis to reservoir characterization will be the interpretation of diagenetic processes through integration of numerous relatively independent analytical techniques.

Fluid Characteristics and Geochemistry

The composition and properties of reservoir fluids including the dissolved species in formation water and brine, oil, hydrocarbon gases and non-hydrocarbon gases are an essential part of reservoir characterization. Undesirable geochemical effects that are commonly encountered in reservoirs such as formation damage, plugging of perforations, scale formation and corrosion of casing and production pipe, channeling of injected chemicals, and slug degradation (precipitation, partitioning, and chemical reaction) may result from incomplete fluid characterization. Few studies have documented the lateral and vertical distribution of the different geochemical characteristics in a reservoir, and predictive capabilities are currently poor.

Fluid characteristics are especially important for EOR operations. Incompatibility between injected EOR slug and formation fluid, and heterogeneity in fluid composition distribution can render an otherwise optimized system ineffective.

Chemical, and isotopic analysis of formation brine and is a powerful tool for identifying heterogeneities such as compartmentalization in reservoirs and fluid leakage due to a break in continuity of confining layers (Szpakiewicz, 1991).

Well Logging

Advances in logging techniques include the development of the laminated sand analysis (LSA) tool that has increased resolution and enables the detection of hydrocarbons in thinly bedded intervals, the electromagnetic propagation tool (EPT), the geochemical logging tool (GLT), and the nuclear magnetic log (NML) (U.S. DOE, 1991). Capabilities of core-calibrated wireline logging data that can obtain information related to geochemistry, sedimentology, stratigraphy, and structural geology has also increased (Worthington, 1991 p.123). New logging techniques such as the electromagnetic propagation tool (EPT) provides flushed zone saturations from which a petrophysical textural parameter can be derived. Other advances in the logging area include high resolution electrical imaging of the borehole wall to investigate bedding, structure, and depositional facies. The formation microscanner provides conductivity images with a vertical resolution of the order of a centimeter (Worthington, 1991).

Areas of needed research in logging techniques include (1) determination of permeability from logs, the current state-of-the-art technology allows only static information; (2) extension of the distance away from the borehole that the log measures, that is currently only a few feet; (3) increased vertical resolution of well logs, the current averaging of properties causes errors in fluid saturation estimates and hydrocarbon detection in thinly bedded rocks. Other areas include an improved understanding of the interrelations of elastic properties (acoustic data measured at different scales). Methods of calibrating seismic data (megascale) with interwell measurements (macroscale) also needs improvement. Acoustic measurements are fundamental to data integration for they can be made routinely at all scales from the laboratory to surface geophysics.

Geochemical Tools

Geochemical tools use nuclear measurements to infer a geochemical signature in terms of elemental abundances within the reservoir rock. The elemental concentrations are then used to predict mineralogy (Hertzog et al., 1987). This approach relies strongly on the integrity of element-to-mineral transforms. Much more work needs to be done to establish whether these transforms are universally applicable or reservoir specific, or have little meaning because of the non-uniform chemical composition of naturally occurring minerals (Worthington, 1991).

Downhole Permeability Estimation

"Refined continuous estimates of permeability at the bedding scale, for input to dynamic models, will be sought through some of the sophisticated logging tools that are either just becoming established in terms of oil-industry applications or are still under development. For example, the analysis of Stoneley waves from sonic waveform logs has already provided some promising indications of permeability prediction" (Cheruvier and Winkler, 1987). The development of proton magnetic resonance tools that are not excessively affected by the wellbore environment (Jackson, 1984) might lead to more meaningful estimates of pore (surface) characteristics for better permeability prediction in situ.

Geophysics and Cross-Hole Tomography

Recent developments in seismic techniques have expanded their use to more detailed reservoir architecture imaging and also to interwell front movement monitoring (Caldwell, 1989). The main constraint to their extended application is the cost, the computer intensiveness, and often insufficient resolution for facies definition. This constraint can be addressed by selecting the areas in which seismic data will be collected and by making maximum use of the existing core and log data together with the available seismic data.

Advances in cross-hole tomographic methods allow (1) identification of high-porosity zones; (2) selection of infill well locations; (3) monitoring of reservoir dynamics such as the movement of gas cap during primary production and fluid front advancements in EOR projects; and (4) collection of information for structural and stratigraphic mapping on the interwell scale. Three-dimensional, high-resolution seismic measurements provide increased resolution which has a potential for mapping lithology and porosity at depth on a gross scale.

Advances in geophysical techniques include the following:

Increased resolution in subsurface imaging: With a greater number of recording channels and the ability to record higher frequencies, it is now possible to obtain much greater resolution in subsurface imaging, making seismic techniques highly desirable in planning development drilling, secondary and enhanced oil recovery operations. Particularly, 3-D seismic has been used to map complex fault patterns in great detail, providing information that is vitally important to the petroleum engineer before planning any secondary or tertiary project which involves injection of expensive chemicals and fluids into the reservoir.

Vertical seismic profiling (VSP) data will provide geological information in the interwell areas much like the 2-D seismic, but VSP data normally will have higher resolution than the surface seismic because the geophones are located inside the borehole, close to the object being illuminated by the wave field. Like 2-D surface seismic; however, VSP will only provide information along a geological section. Theoretically there is no depth limitations to any of these methods but data resolution normally deteriorates with depth because of rapid attenuation of higher frequencies with depth.

Estimation of rock and fluid properties: Characteristics of seismic waves like amplitude, phase and interval velocity change between seismic events have been correlated with porosity, fluid type, lithology, pay thickness, and other reservoir properties. The correlations usually require calibration by borehole data and well logs.

Seismic amplitude values have been directly transformed into the product of porosity times thickness by geophysicists from Arco Oil and Gas Company in its North Slope, Prudhoe Bay oil field in Alaska (Robertson, 1989), where the method was used to map porosities in under drilled parts of the field. Seismic lithologic modeling has been successfully used in studying the variations in acoustic impedance and their associated implications on porosity across the Yaphour oil field in Abu Dhabi (Zake et al., 1990).

In recent years, a number of seismic techniques have been used in monitoring movement of fluids in the reservoir during EOR processes. This flow monitoring is still in an experimental stage and major advances are expected in the near future. The seismic technique will be particularly useful in monitoring EOR processes like steamflood where the extreme temperature and pressure of the injected fluid create sufficient changes in acoustic impedance and consequently the reflected seismic wavelet so that the movement of fluid could be detected on the seismic section (Harben et al., 1991). Greaves and Fulp (1987) report of a successful monitoring of an in situ combustion project, and Pullin, Matthews and Hirsche (1987) have described the imaging of fluid movement at the Athabasca tar sand thermal EOR project in Calgary, Canada.

Determination of rock mechanical properties and fractures: With the introduction of the three-component geophones in seismic surveys, it is now possible to record in the field, besides the compressional, p-waves measured in conventional surveys, two horizontal components of shear waves (the s-waves). The shear wave data immediately provide very useful reservoir information. First, Poisson's ratio of rock masses may be estimated from the P and S wave data which provide information about mechanical strength of rocks. Since shear waves cannot propagate through fluids, they have been used in mapping fluid filled fractures. The ratio of compressional and shear waves has also been used in lithology identification because of the different propagation characteristics of P and S waves.

Tatham and Stoffa (1976), Ensley (1989), Nations (1974), and several others have discussed how combined studies of P and S wave velocities can help in identifying lithologies and in determining fluid saturations. Davis and Lewis (1990) discuss how three-component geophone systems could be used to study fracture density in a chalk reservoir and have demonstrated how the map of fracture density and connectedness is correlatable with production.

Integration of seismic and well log data with geostatistics for accurate reservoir description for reservoir simulation: The various recently developed geostatistical techniques could be integrated with Seismic and log data to provide reservoir data at grid points required for reservoir simulation. Philippe Doyen (1988) demonstrated the use of geostatistical coke rigging method with seismic transit time data to study the porosity variations in a channel-sand reservoir from the Taber-Turin area of Alberta, Canada.

Well Testing

Transient pressure testing is an important diagnostic tool, especially for the definition of near-wellbore and interwell conditions. Transient pressure testing provides a reservoir description which is directly applicable for production and reservoir engineering calculations, where the values are directly measured and not inferred. Well tests sample a much larger volume (approaching the drainage volume of the well) than core-sampling and well logs that only measure near wellbore properties and thus averages the properties over a given volume of the reservoir. Results are obtained in a relatively short period of time and with minimal effort. Well testing has been used extensively in the 1970s and 80s to detect interwell communication and diagnose near-well bore conditions with great success. Recent advances (Ramey, 1990) include the use of log-time derivative of the storage and skin solution with the Gringarten form of storage type curve to obtain a unique match with field data, computer aided interpretation and better pressure and flow rate measuring gauges.

Transient pressure testing, due to its usefulness, continues to be under research and development in all phases of field operations, as evidenced by several review papers (Ehlig-Economides et al., 1990, Ramey, 1990; and Gringarten, 1986)

The following areas were identified (Kamal, 1990) in a recent SPE paper as the areas that need further research:

1. Application to more heterogeneous formations. Recent applications are limited to composite reservoirs (Brown, 1985; Olarewaju and Lee, 1987a,1987b; Yu and Yang, 1990), with only a couple of known symmetrically located variations in properties, or a few discontinuities.

2. More sophisticated testing methods involving computers and advanced communication capabilities to transfer, process, and analyze data.

3. Integration of several reservoir characterization methods to obtain more comprehensive reservoir descriptions.

Tracer Test

Well-to-well tracer testing is another engineering technique that was used extensively in EOR field project reservoir characterization. This method can identify the presence of barriers, channeling, and flow trends between injection and production wells. Abbasxadeh-Dehghani and Brigham (1984); Brigham and Abbasxadeh-Dehghani (1987) developed a methodology for the application of tracer techniques to reservoir characterization and to the development of quantitative models for a heterogeneous reservoir. The technique was successfully applied to describe and quantify areal and vertical heterogeneity (Ohno et al., 1985; Singhal et al. 1989). However, in a simulation study on the effect of heterogeneity on tracer response, Mishra et al. (1988) cautioned that the use of the convection-diffusion equation for modeling tracer in reservoir with severe heterogeneity is open to question. Allison et al. (1991) extended this technique to describing reservoir heterogeneity and residual oil saturation distribution in the reservoir. The advantage of multiple tracers from a single injection well was clearly demonstrated in their work. This method provides a powerful tool for determining residual oil saturation distribution, which is one of the most important (if not the most important) parameters that determine the success or failure of an EOR project.

Other effective methods for determining residual oil saturation (Chang et al., 1988) are resistivity log, pulsed neutron capture logs, pressure coring, single-well tracer tests, nuclear magnetism log, carbon/oxygen logs and the electromagnetic propagation tool. A single-well chemical tracer test that can be applied to multilayer reservoir with interlayer communication (Seetaram and Deans, 1989) has been developed. In comparing single-well tracer test with interwell tracer, carbon/oxygen log and pulsed neutron capture log (log-inject-log), Causin et al. (1990) found that while a single-well tracer test can be difficult to interpret in heterogeneous reservoir, an interwell tracer test, on the other hand, can give an average remaining oil saturation.

Wood et al. (1990) also confirmed the cost-effectiveness and ease of application of the interwell tracer technique.

In single-well and well-to-well tracer tests, the injected aqueous solution tends to flow along water-saturated flow zones; therefore, the test would bias the result toward water-saturated pore volume. In addition, in well-to-well tracer tests, interwell flow barrier is a function of permeability and relative permeability (a function of saturation, lithology and wettability). Without additional information on the lithology, pore size distribution, and wetting behavior of the barrier, the oil saturation and permeability calculated from a tracer test will not be unique. It is therefore important to incorporate geologic information (depositional and diagenetic models) into tracer test analysis.

Analyses of injection and production data to evaluate reservoir performance are tools that have been used extensive in the petroleum industry. Recently, attempts have been made to extend the application of these tools to reservoir characterization. By production history matching (Honarpour et al., 1988) and mapping the waterfront advancements during the secondary production (based on watercut production data), and comparing them with front advancements generated by simulation, one can identify both barriers to flow as well as high-permeability zones (Honarpour, et al., 1989). The existence of production history, combined with simulation can be a very useful tool in reservoir characterization. By carefully monitoring the pressure and injection flow rates one can construct Hall plots, whose slopes indicate the permeability of the regions surrounding the injection wells (Honarpour and Tomutsa, 1990).

Relative Permeability

Relative permeability is one of the most important input parameters for reservoir simulation and recovery prediction; the reliability of recovery forecast depends critically on the accuracy of this parameter. Yet it is also one of the most abused parameters for reservoir modeling, during which its value is often adjusted at will to history match production data. Accurate relative permeability data are difficult to obtain because they require careful execution of the procedures established for relative permeability measurement (Heaviside, 1991). For reliable measurement, the native wettability of the core has to be maintained, and the saturation history of the recovery process has to be simulated. The importance of measuring in situ fluid saturation at reservoir conditions during relative permeability measurements was emphasized by Honarpour and Mahmood (1988) and Honarpour and Maloney (1990). Estimation of relative permeability from unsteady state measurement is tedious and usually involves judgment based on the experience of the analyst. Sometimes simplifying assumptions are made that compromise the accuracy of the results. Recent advancement in this area includes the use a variety of regression methods for automatic matching (Watson et al., 1988; Yang and Watson, 1991). Application of these methods will reduce inaccuracy due human errors and approximations.

Three-phase relative permeability measurements are even more difficult than oil/water or gas/oil two-phase relative permeability. The results of Oak (1990) and Maloney et al. (1988) are among the few accurate three-phase relative permeability data that are available in the literature. Predicting three-phase relative permeability from two-phase data using Stone's method (Stone, 1970) is not satisfactory (Oak, 1990).

Determination of the grid-size effective relative permeability values from core-size measured values for use in simulation is an area of active research (Kasap and Lake, 1990); however, more work in this area is required.

Information From Reservoir Analogs

Outcrop exposures of reservoir rocks provide laterally continuous sampling of rock characteristics and provide lateral information on scales not available from reservoir data. Outcrop studies can be a valuable, low-cost source of high quality geological data. In the past decade, numerous papers have presented the results of quantitative outcrop studies, including both dimensions and geometries of sandbodies (Lowry, 1989; Miall, 1988) and permeability and porosity measurements (Tomutsa et al., 1986; Goggin et al., 1989). These data will help define reservoir geometry, compartmentalization, rock type distributions, e.g., shale length distributions (Haldorsen and Lake, 1982; Haldorsen and Chang, 1985) faulting, fracturing, and variability and trends. These data also will help define the scale at which further data should be acquired in the reservoir studied, as well as the optimum spacing for primary, secondary, and tertiary recovery.

The constraints in utilizing outcrop data are (1) the availability and accessibility of outcrops analogous to the reservoir; (2) the time required for preliminary reconnaissance work to identify analogous outcrops; (3) differences in facies architecture, diagenetic imprint, tectonic structure etc. between outcrops and reservoir; and (4) methods to apply outcrop data in characterizing subsurface reservoirs.

Advances in the use of analog occurrences of reservoir formations have resulted from need to incorporate and thereby quantify geological information into reservoir simulation models. Greater use of outcrop information has resulted in greater amounts of quantitative geological information on facies geometry and dimensions and spatial variations of reservoir properties within facies (Jackson et al., 1987). Permeability and porosity data have allowed correlation of facies and rock types with petrophysical characteristics and the delineation of flow units.

The caveat for applying information from analog depositional systems to reservoir simulation models, however, is that the underlying assumption that the statistics of facies dimensions, frequencies of occurrence, and interconnectedness ratios of particular facies within particular depositional systems are transferable from one reservoir to another. Although, theoretically, many reservoir properties may be transferable from one deposit to another (Figure I-9), it is not yet known how to assess the degree of similarity and the applicability of data from analogue occurrences.

For example, the deposition of fluvial channel deposits within different tectonic settings may result in very different grain sizes, sorting, and channel geometries due to the effects of rate of tectonic movement, sea level, and sediment supply. The fluvial channelbelt sandstones deposited during conditions of low subsidence rate may form vertically and laterally interconnected, blanket-like reservoirs, in contrast to the isolated, stringer-like sandstone bodies formed during periods of higher subsidence rate (Cross, 1991). Assessment of these controls requires establishing a high-resolution time framework and placing the distributions of facies within that framework (Cross, 1991).

Classification of depositional systems is based on the processes that formed the rock and their paleogeographic locations (e.g. terrestrial, shoreline, shallow or abyssal marine). The classification allows prediction, to some degree, of geometries and dimensions of the deposits as well as the distribution of reservoir-quality rocks.

Current classifications, however, often do not include the first-order depositional controls such as relative sea level changes, rate of sediment supply, and basin subsidence. To increase the degree of transferability, classification schemes may need to be refined, resulting in finer subdivisions of depositional systems based on differing controls on the sedimentology. Current classification systems for deltas, for example, are based on a number of features such as (1) the depositional processes dominant in the formation of the delta, i.e., fluvial-, tide, and wave-dominated; (2) the dominant grain size, i.e. sand-rich and mud-rich, deltas; or (3) the position on the shelf, i.e. shelf edge and stable shelf deltas. Arguments have been made by Pulham(1989) that the observed geometry of sandstone bodies in some deltaic deposits is not that which might be predicted from an analysis of the depositional fluvial and wave processes alone. He points to deformation and basin subsidence as integral, important processes in prediction reservoir geometries.

	Volumetrics	Continuity	Porosity	Absolute Perm.	Rel. Perm.	Saturations	Fluid Type	Pressure Temp.	Drive Mechanism	Type of Fluid Flow
DEPOSITIONAL CHARACTERISTICS										
External Geometry	0	0								
Internal Geometry		0	0	0	0	0			0	X
Pattern of Variation (Quantitative Res. Properties)	⊗	0	0	0	0	0				
Absolute Values (Quantitative Res. Properties)	⊗	⊗	⊗	⊗	X	X	X	X	X	X
DIAGENETIC CHARACTERISTICS										
Compaction (including geopressure)	X		0	0			X	0		X
Cementation	X	X	0	0	0	0	X	0		X
Dissolution	X	X	0	0	0	0	X	0		X
Recrystallization	⊗	X	0	0	0	0	X	0		
TECTONIC CHARACTERISTICS										
Folding	0	0	0	⊗		0	0			
Faulting	0	0	X	X			X	⊗		X
Fracturing	0	0	X	X	0		X	⊗		X
FLUID CHARACTERISTICS										
Hydrocarbons				0	0	X	X	0		X
Non-HC gases			X	0	0	0	0	X	X	X
Formation Water		⊗	0	0	0	X	X	X	X	X
Injected Fluids	0			0	X	X	X	X	0	X

0 = Property transferable
⊗ = Partially transferable (e.g. within a basin)
X = Property not transferable

FIGURE I-9. Geological and reservoir properties: Transferability between analogous deposits (Modified from Lake, et al., 1991).

Future research on the degree to which information from reservoir analogs can be incorporated into reservoir models and the methods to do so will greatly enhance the ability to develop detailed, representative reservoir models. Additional studies of reservoirs, outcrops and modern environments are required to develop large geologic data bases from which statistically significant characteristics for particular deposystems or reservoir classes can be determined. The determination of the characteristics typical for a reservoir class will allow assessment of the degree of transferability or portability of information among similar class reservoirs. Finer subdivisions within the current depositional models may be required to assign meaningful reservoir classes.

The call for greater amounts of detailed geologic information underscores the need for geologic databases that are well-integrated, able to process large amounts of data including semi-quantitative information, and produce graphic output for the full range of geological and engineering data (Stark, 1991). Automated interfaces between the database and other programs such as well log analysis and various simulation models must be available where the capabilities are not built into the database.

SUMMARY

Reservoir characterization is a complex and difficult task that requires information from diverse sources on a wide range of scales and the integration of analyses from a broad range of disciplines including geoscientists, physical scientists, and engineers. The constraints in reservoir characterization are due to: (1) the complexity of the rock and fluid distributions, and (2) the typically inadequate amount of information available even in the most ambitiously sampled reservoirs.

The challenges in reservoir characterization include: (1) obtaining sufficiently detailed reservoir information; (2) constructing predictive models of spatial distribution of reservoir characteristics in the interwell area; (3) incorporating the abundant semi-quantitative information available from the reservoir into simulation models and (4) developing scaling or averaging procedures for determining representative simulator grid block values.

To achieve cost-effective, accurate reservoir characterization, the following research areas need to be pursued:

Near-term

(1) Development of computer-based database management systems that allow data from all disciplines, at all scales, including non-numeric information to be easily integrated and output to a wide range of end-user applications.

(2) Development of methodology for systematic reservoir characterization that includes systematic data collection, analyses, integration and utilization of all types of data (including semi-quantitative) from various sources and that addresses the types and amount of data required for various recovery processes.

(3) Innovative methods to extract reservoir properties from engineering data, especially data from older reservoirs.

(4) Predictive models of the spatial distribution of reservoir characteristics in the interwell area. The development of these models requires large amounts of quantitative geologic and petrophysical information from reservoir analogs.

(5) Development of a reservoir classification system and the determination of the degree to which properties can be transported from one reservoir to another.

(6) Determination of accurate relative permeability data and correlations.

(7) Determination of rock-mechanical properties, from P and S wave studies to determine variations in rock-mechanical properties like compressibility, Poisson's ratio, etc. Integration of seismic results with laboratory measured values from core sample.

Mid-term

(1) The development of diagenetic models that predict the spatial distribution of diagenetic phases within specific reservoir strata on the interwell to field scale.

(2) Documentation and model development of the spatial distribution of geochemical characteristics within a reservoir.

(3) Increased penetration distance and vertical resolution of petrophysical characteristics measured by well logging tools.

(4) Integration of seismic date (megascale) with interwell measurements (macroscale) and core measurements macro- to micro-scale.

(5) Scaling-up procedures of various reservoir properties including relative permeability, for determining simulator grid block values.

Long-term

(1) Determination of reservoir permeability from geophysical techniques including acoustic logging and crosshole tomography.

(2) Integration of theoretical seismic model studies with field data.

(3) Application of well testing to more heterogeneous reservoirs.

(4) Improved geophysical techniques for reservoir definition at a reasonable cost.

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CHAPTER 11
ENVIRONMENTAL CONSTRAINTS ON EOR

By Min K. Tham

INTRODUCTION

Protecting the environment and preventing contamination of the Nation's drinking water, soil, and air as a consequence of oil and gas exploration and production activities have always been objectives of the U.S. DOE (DOE 1990). In anticipation of the widespread use of enhanced oil recovery methods, which can contribute to the U.S. efforts to achieve energy independence, DOE supported and performed studies to evaluate possible effects of EOR on the environment in the late 1970s and early 1980s (Wilson and Franklin, 1978; Donaldson, 1978; Silvestro and Desmarais. 1980; Riedel et al., 1981; Millemann et. al., 1982). The 1984 National Petroleum Council study (National Petroleum Council, 1984) also listed a number of potential impacts that may occur as a result of application of EOR in the field. The concerns raised at that time—land disturbance, deterioration of surface water, ground water contamination, and air pollution—are also valid at the present when the U.S. DOE is contemplating a number of field projects in the implementation of the Advanced Oil Research Program.

Construction of roads, well sites, crude oil collection and separation facilities, waste disposal pits, and surface spills are some of the sources of land disturbance and causes for surface water deterioration. Of these, waste disposal pits, especially those for drilling mud and cuttings (Leuterman et al., 1988), are of the greatest concern.

Potential sources of ground water contamination are from injection wells for waterflooding, steamflooding, gas flooding, chemical flooding, and produced water disposal. Leaky well casings due to corrosion and overpressurization are the main causes for contamination of underground drinking water in oil and gas producing areas. A concern raised in the NPC study regarding competition for freshwater supply for chemical EOR will be of less importance because of recent advances in chemical EOR technology. Salinity-tolerant surfactant systems (Maerker and Gale, 1990) and polymer flooding systems (Moffit et al., 1990) are now available that do not require freshwater preflush or freshwater for preparing chemical slugs.

Dust particles generated in preparing well sites; emissions of hydrocarbons and hydrogen sulfide gases from wellheads; nitrogen oxides, carbon monoxide, sulphur dioxide and hydrocarbon gases from steam generators and internal combustion engines; and carbon dioxide and hydrocarbons from produced gas separation plants are some of the sources of air pollution. Lease-crude-fired steam generator exhaust is the main air pollution concern in oil production.

Many of the above-mentioned pollution problems are common to EOR and non-EOR oil and gas production activities. Crocker et al. (1989) reviewed many of the problems affecting oil and gas exploration and production and evaluated 32 topics as potential candidates for environmental RD&D. They selected oxygen-activation logs for detecting leakage, toxicity test for drilling fluids, environmentally safe drilling fluid, in situ treatments of wastes/soil, effective technology transfer, comprehensive waste management, and a pollution prioritization protocol for abandoned wells as areas in which to concentrate RD&D efforts. In this report, discussion will focus on the impact of regulations on the application of EOR, waste (air, water and solid pollutants) emitted from EOR projects, some of the recent efforts to minimize waste generation, and waste management methods.

ENVONMENTAL REGULATIONS

To protect the environment, Congress has passed a number of environmental statutes that affect oil and gas operations. These include the Clean Air Act, Safe Drinking Water Act, the Clean Water Act, and the Resource Conservation and Recovery Act (RCRA). To comply with these regulations that apply to EOR operations, one needs to study these laws and collect information on the permits that must be obtained before starting an EOR project. The Environmental Regulations Handbook for Enhanced Oil Recovery - 1983 Update (Wilson, 1983) is an excellent source for such information. However, in recent years, environmental regulations and legislation have grown—the number of environmental bills introduced at the federal and state level increased from 945 for 1987 and 1988 to 1041 for the first 9 months of 1989. Some of these regulations have the potential of creating considerable constraints on expansion of oil production through the application of EOR. It is safe to assume that this handbook is outdated. Sarathi (1991) discussed the various regulations and permitting requirements for thermal enhanced oil recovery. His work is a welcome addition to the source of information for compliance to environmental regulations in thermal EOR. A similar update that is applicable to other EOR processes is recommended.

Complex regulations could significantly constrain the application of EOR processes in the field. Flaim (1988) argued that regulation of drilling fluids as hazardous waste under the Resource Conservation and Recovery Act could cause the unemployment rate in major oil producing states to rise by as much as 6%. Drilling fluids and produced waters were exempted from being classified as hazardous waste under RCRA Subtitle C by the EPA in 1988. However, it was predicted that Congress would likely reevaluate this exemption in 1991 (*Oil & Gas Journal*, 1990). Godec and Biglargbigi (1990) through an analysis of the effect of environmental regulations on U. S. crude oil production concluded that increased regulation on exploration and production operations can have a significant impact on potential ultimate crude oil recovery. Depending upon the level of regulation, reserve loss (at $32/barrel oil price) varies from 3 to 7.8 billion barrels of crude oil.

Blevins (1990) in a review of steamflooding in the United States stated that "these ubiquitous regulations are now the critical path for planning all new steamflood operations," and pointed to air quality regulation as the most serious challenge to the oil industry's ability to expand future steamdrive operations in the San Joaquin Valley. It is obvious from these discussions that environmental regulations will be a key constraint to further expansion of E&P activities and to increasing crude oil production using EOR. The pending legislation that may remove the exemption of E&P wastes as hazardous wastes for regulation under the Resource Conservation and Recovery Act (Oil & Gas Journal, 1990) could turn out to be the single most important factor that determines whether some of the marginal wells can continue operating, thereby preserving the resources for future EOR, or whether these wells will be forced to be abandoned prematurely. A significant amount of resources which otherwise would be recoverable using EOR technology (as much as 3.5 to 8.6 billion barrels) could be lost due to premature well abandonment (Biglarbigi et al., 1990).

The pressure to protect the environment by the public, environmental activists, and politicians will remain strong (Sullivan, 1990); yet, significant progress has been made toward environmentally benign oil and gas production operations (Arscott, 1989). The oil industry now realizes the need to take the initiative to monitor oil and gas production and to minimize waste production to prevent damaging the environment as a means to forestall overregulation. The oil industry feels that pollution control is too important an issue to be left to activists and politicians (Sullivan, 1990) and that it is advisable to cooperate with public interest groups, environmental groups, and government to resolve disputes through cooperative agreements instead of antagonistic actions that may lead to calls for increased regulation (Arscott, 1989). An example of this cooperation is a recent report by the Interstate Oil Compact Commission (EPA/IOCC, 1990) on regulatory needs. The report is a result of input from IOCC, state oil and gas regulatory officials, oil and gas industry, and environmental groups. It was hoped that through this balanced approach the environment could be protected while avoiding excesses that could harm consumers and the petroleum industry (*Oil & Gas Journal*, 1990).

MINIMIZATION OF AIR POLLUTION

Emissions of hydrocarbons, hydrogen sulfide, and carbon dioxide at wellheads are problems associated with primary and secondary production, and at the present are not major problems in EOR production. In cyclic steam and steamflooding, the main pollutants of concern are ozone and particulates. To control these pollutants, abatement of emissions from lease crude fired steam generators that generate sulfur dioxide, oxides of nitrogen, carbon dioxide, carbon monoxide, unburned hydrocarbons, and particulates is practiced. The same gases could also be emitted during in situ combustion operations if these gases are allowed to leak to the atmosphere. Nitrogen oxide emissions from steam generators and internal combustion engines are now being controlled by controlling the combustion process. Well vent collection systems, tank vapor recovery systems, and sump covers are the systems used to control hydrocarbon emissions (Peavy and Braun, 1991). Sulfur dioxide and particulate emissions can be controlled through the use of scrubbers (Sarathi, 1991; Kaplan et. al., 1983). Emission of these pollutants can also be minimized by using gas-fired steam generators. Cogeneration gas-fired generators are becoming economically attractive. By converting 28 oil-fired steam generators and 24 oil-fired water/oil treating units to a 225-megawatt cogeneration plant, it is anticipated that an overall pollutant reduction of 12 million pounds can be achieved over a period of 20 years, and the emission level is only 88% (for NO_x) to 11% (for CO) of the allowable levels (Western and Nass, 1990). Stricter air quality regulations may force more conversions to more gas fired steam generators irrespective of economics.

Air quality control in oil and gas production is regulated by the Federal Clean Air Act and local regulations such as the Air Quality Control District Regulations of the State of California. Sarathi (1991) provides a comprehensive discussion of the relevant regulations and legislation for air quality control and other waste management for thermal enhanced oil recovery. This information will not be reproduced in this report. The recently passed Clean Air Act of 1990 required reduced ground level zone by 15% in polluted areas over the next 6 years (Zahodiakin, 1990). This could have a significant impact on the future expansion in steamflood EOR, especially for the counties in the San Joaquin Valley of California.

MINIMIZATION OF WATER POLLUTION

EOR processes involve injecting fluids (brine, steam, surfactant, polymer, alkali, CO_2, nitrogen, and hydrocarbon gases) into the reservoir. Leakage of these fluids into drinking water sources is a major concern of federal and state regulators, environmentalists, and oil and gas producers. The corrosive nature of brine, steam, alkali, and CO_2 increases the potential for such leakage.

Enhanced oil recovery fluid injection and produced fluid disposal wells are regulated under state Class II well underground injection control (UIC) programs. The main concern in this program is the potential contamination of underground sources of drinking water (USDW) through leaky well casing. To prevent polluting USDW, regulations require testing the mechanical integrity of the well casing every 5 years. The regulation also allows demonstration of mechanical integrity through (1) monitoring of annulus pressure, (2) pressure test with liquid or gas, or (3) records of monitoring showing the absence of significant changes in the relationship between injection pressure and injection flow rate for Class II enhanced recovery wells. The reliability and how stringent a test should be to prove mechanical integrity are still a controversial issue. Madden et al. (1989) argued that continuous monitoring of the volume of annulus fluid with monthly or quarterly positive annular pressure can be more reliable than a standard annulus pressure test because of more frequent observations than the maximum 5-year interval of the standard annulus pressure testing method. Kamath (1989) shows that annular liquid level monitoring is the simplest and most practical method for monitoring casing leaks. Monitoring annulus gas pressure does not appear to be technically reliable because of the possible effect of temperature variation on gas pressure. New pressure testing methods are also being proposed for wells with perforation above the packer or for testing casing in wells without packers or packerless disposal wells (Wilson, 1988a; Wilson, 1988b; Herlihy et al., 1987a; Herlihy et al., 1987b). Janson et al. (1990) successfully tested a continuous annular monitoring concept that incorporates pressure testing on the tubing and packer along with continuous annular monitoring. Using this method in a Class II injection well that has insignificant leaks will allow the continued use of this type of well and avoid expensive remedial action.

MINIMIZATION OF SOLID WASTES

According to RCRA, solid waste is defined as any material that is discarded or intended to be discarded. It may be solid, semisolid, liquid or contain gaseous materials. The largest volume of solid wastes is derived from drilling operations, including drilling mud, drill cuttings, etc. In 1985, the U.S. generated 360 million barrels of drilling fluid. The drilling waste fluids are generally evaporated, discharged to the surface, transported off site, or injected down a well annulus. Drilling waste solids are usually disposed by burial or land spreading at the drilling site. A study by the American Petroleum Institute shows that current drilling waste management practices have no significant potential hazard to human health or the environment (API, 1987).

Current efforts to minimize the environmental impact of drilling activities include designing non-toxic (or low toxicity) drilling fluids and lubricants and development of land farming (Whitfill and Boyd, 1987; Loehr et al., 1987). Efforts have been made to reduce the volume of wastes through various dewatering technologies: centrifugation (Water Pollution Control Federation, 1983; Malachosky et al., 1989,) and filtration (Townley et al., 1989). Recycling of drilling mud is another method being used for minimization of wastes. Treatment of contaminated drill cuttings and soil by bioremediation is also practiced (Whitfill and Boyd, 1987; Hildebrandt and Wilson, 1990).

WASTE MANAGEMENT

Good waste management practices should comply with applicable regulations, minimize exposure to potential liability as a result of improper handling of wastes, and do so economically. The Interstate Oil Compact Commission (IOCC, 1990) recommends following the hierarchy of source reduction, recycling, treatment, and proper waste disposal as a good waste management practice. Stillwell (1990) used an area waste management plan concept by developing a plan for an area having similar regulation, environment, geology, and production operations. Within a chosen area, these steps were used: (1) waste identification, (2) classification of waste by categories, (3) identification of all waste management options for specific waste, (4) selection of acceptable waste management practices, (5) prioritization of selected practices, and (6) development of waste management plan. The need to communicate waste management strategies to field operations personnel handling the wastes was emphasized. Through these steps, waste management goals and performance were established, improvements were made in understanding waste and waste management requirements, and communication and implementation of waste management goals were achieved (Stillwell, 1990). Sullivan (1990) and Arscott (1989) also emphasized sound waste management through waste minimization, substitution of less toxic material for toxic ones, recycling, treatment and proper disposal as a means to achieve environmentally safe oil and gas production operations.

SUMMARY

The state-of-the-art of air, water, and solid waste pollution control technology is adequate for the prevention of the deterioration of the Nation's air and drinking water source. Stricter environmental regulations will only increase the financial burden on the producer and impede wide spread application of EOR technology in the field. Classification of exploration and production wastes currently exempt from RCRA Title C as hazardous would have a devastating effect on U.S. oil and gas production capacity. Recently, the oil and gas industry has taken the initiative to confront environmental issues and devise preventive methods to eliminate violation of environmental law and to work with regulatory agencies to solve some of the potential environmental problems. The solution to the Nation's environmental problems could be solved through cooperative efforts of the federal and state regulatory agencies, environmental activists, DOE, and the oil and gas industry. Additional regulatory control may not be necessary.

The recommended areas of research are:

1. Update the Environmental Regulations Handbook for Enhanced Oil Recovery.
2. Establish a consortium of government, industry and environmental groups to define problems and to find solutions.

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CHAPTER 12
REVIEW OF SELECTED DOE-SPONSORED RESEARCH PROJECTS

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The Department of Energy has sponsored a number of research projects in advanced oil recovery over the years. The results of these projects are reported in the DOE *Quarterly Progress Review of Contracts and Grants for EOR Research* and annual reports. Since the early 1970s DOE has funded 327 EOR projects at a cost of $265,212,188 (*Quarterly Progress Review No. 63*, 1991). In this chapter, a selected number of projects are reviewed, and the achievements reported by these projects are summarized. The constraints that these projects are addressing are identified in the previous chapters (summarized in chapter 14) and in part II .

GAS EOR

The technical constraints identified for gas EOR in chapter 2 and part II are poor sweep efficiency and uncertainty in performance predictions. Almost all research on this EOR process has been focused on these two problems. During 1989 and 1990, the DOE sponsored 10 projects in gas displacement research. These projects and the constraints which these projects are designed to overcome are listed in table I-21. Among these 10 DOE-sponsored gas EOR research projects, four were devoted to mobility control problems; four examined phase behavior and displacement mechanism prediction problems, and two addressed both problems. Most of these research projects were laboratory studies; only two projects were designed for field tests.

Research on mobility control technology development is focused on foam (or dispersion), direct thickener, and entrainer methods. The foam technology development research includes surfactant property studies, foam flow behavior modeling, and simulation. A fundamental understanding of CO_2 properties is lacking, and some confusion exists in foam technology research. Because of the complexity of foam technology, some duplication in research efforts do exist in the DOE program. Research on foam requires multidisciplinary efforts including areas such as chemistry of surfactants, rheology, adsorption, thin-film properties, and multiphase flow in porous media. The multidisciplinary nature of foam research and inadequate understanding of the basic problems in mobility control using foam warrant a long-term approach to solving these difficult problems. A long-term policy and an integrated research plan are needed for CO_2-foam research.

The effectiveness of using low-molecular-weight surfactants at concentrations below their critical micelle concentrations has been investigated by Morgantown Energy Technology

TABLE I-21. - Selected DOE-sponsored projects in gas EOR research

Title	Reservoir Heterogeneity	Mobility Control	Production Mechanism	Injectivity	Recovery
Enhanced Oil Recovery Model Development and Validation (Morgantown Energy Technology Center)			X		
Quantification of Mobility Control in Enhanced Recovery of Light Oil by Carbon Dioxide (Morgantown Energy Technology Center)		X			
Enhanced Oil Recovery Systems Analysis (Morgantown Energy Technology Center)			X		
Improvement of CO_2 Flood Performance (New Mexico Institute of Mining and Technology)	X	X	X		
Field Verification of CO_2-Foam (New Mexico Institute of Mining and Technology)		X			
Scaleup of Miscible Flood Processes (Stanford University)		X			
Statistically Designed Study of Parameters of a Carbon Dioxide Equation of State (Johns Hopkins University)			X		
Gas-Miscible Displacement (NIPER)		X	X		X
Development of Improved Immiscible Gas Displacement Methodology (NIPER)		X			
Cyclic CO_2 Injection for Light Oil Recovery Performance of a Cost-Shared Field Test in Louisiana (Louisiana State University)	X		X	X	

Center (METC). The project by NMIMT-PRRC, "Field Verification of CO_2-foam," was designed for field testing CO_2-foam. Accurate, detailed reservoir formation information is important to field test design; otherwise, tests will provide scarcely any advancement to foam technology development. In direct thickener method development, NMIMT-PRRC has been devoted to the synthesis of CO_2-soluble polymers as viscosifiers for CO_2. They have concentrated on particular types of "Method II" polymers which are ionomers made with relatively short-chain polymers that contain a controlled number of ionic groups in each molecular unit. This method is hindered by the low solubility of these polymers in CO_2 and problems such as chromatographic separation and partitioning in water phase or oil phase, which are critical to the thickener method. In the entrainer method study conducted by NIPER, research was concentrated on entrainer selection and screening. For both direct thickener and entrainer methods, research should not focus only on solubility problems but also on chromatographic separation and partitioning.

The project by NMIMT-PRRC, "Improvement of CO_2 Flood Performance," was also involved in reservoir characterization. Accurate, detailed reservoir formation information is important to field test design, otherwise, the test will not provide much help to foam technology development.

In the prediction study, the research covers a variety of subjects including equation of state (by Johns Hopkins University), phase behavior and displacement mechanisms (by NMIMT-PRRC, Stanford University), CO_2-oil property (NMIMT-PRRC), asphaltene precipitation (NIPER), scaling (Stanford University), and reservoir simulation (METC). In the equation-of-state study, the project conducted by Johns Hopkins University has been completed. In the fluid property and phase behavior studies, an improved viscosity correlation for CO_2-reservoir oil systems has been developed by NMIMT-PRRC (Lansangan et al., 1990), and thermodynamic models for the prediction of asphaltene and wax precipitation have been developed by NIPER (Chung et al., 1991). The simulation study conducted by Stanford reveals the effect of nonuniform flow and reservoir heterogeneity on phase equilibrium and oil recovery (Araktingi and Orr, 1990). By comparing with laboratory-scale experiments conducted by the University of Wyoming, METC has evaluated the capability of each simulator and identified the importance of incomplete mixing (Ammer et al., 1991). The project by Louisiana State University, "Cycle CO_2 Injection for Light Oil Recovery: Performance of a Cost-Shared Field Test in Louisiana," was designed to provide a base of knowledge on the CO_2 huff-n-puff process for the enhanced recovery of Louisiana crude oil. Since the soak period is one of the most important parameters for CO_2 huff-n-puff process design, this project should be extended to provide information for field process design. Methodology to scale up from laboratory-scale experiments to a field-scale tests is lacking. Lack of scaling techniques and the uncertainty of simulation have hindered the technology transfer from laboratory to field. To improve the accuracy for gas flood performance prediction, more research efforts are needed in the areas as listed in table I-22.

CHEMICAL FLOODING

Chemical flooding projects sponsored by the DOE are listed in table I-23. Included in this table are constraints which these projects are designed to overcome.

Columbia University has made a comprehensive study of retention of chemicals in EOR flooding over a period of several years. The techniques employed have included chemical analysis, spectroscopy, flotation, surface tension measurement, electrokinetics, and calorimetry.

Parameters studied have been surfactant concentration (increasing and decreasing), charge on mineral surfaces, solubility of minerals, ionic composition of the solution (including pH), alcohol and oil content, surfactant structure (anionic and nonionic, various isomers, number and location of sulfonate groups or degree of ethoxylation, comparison of sulfate and sulfonate), composition of mixtures, and character of acrylamide polymer (anionic, nonionic, cationic).

Achievements have been as follows:

1. Delineation of the four regions of an adsorption isotherm for ionic, micelle-forming surfactants and discovery of hemi-micellization.
2. Mapping of regions of precipitation and redissolution in surfactant concentration/salt concentration space.
3. Study of adsorption from mixtures:
   - Competitive adsorption of surfactant, alcohol, oil, and polymer, which leads to complex behavior as composition and concentration are varied;
   - The relative dominance of entropy and enthalpy causes a diverse effect of ethoxylation on solubility and adsorption, and a synergism in adsorption from anionic/nonionic mixtures.
4. Demonstration that many adsorption effects depend on solution chemistry of surfactant; species of anions in salts of weak acids varying with pH, and the impact of hydration of inorganic cations on the tetrahedral structure of water.

TABLE I-22. - Research areas for the improvement of gas flood performance prediction

Phase behavior prediction	Displacement mechanism description	Multiphase flow in porous media description	Numerical technique problems
I. Crude oil characterization ° C_7+ fractions ° Asphaltene fractions II. Finite difference error	I. Molecular diffusion process	I. Three-phase relative permeability II. Oil swelling	I. Numerical dispersion error II. Oil-water saturation distribution
II. Equation of state improvement ° CO_2 - crude oil ° H_2O - crude oil ° CO_2 - H_2O - crude oil	III. Displacement mechanisms in fractured reservoir	III. Grid-orientation error	
III. Phase behavior in porous media ° Effects of heterogeneity and nonuniform flow on CO_2-reservoir oil phase behavior. ° Asphaltene precipitation ° Condensation for gas condensate			

TABLE I-23. - Selected DOE-sponsored projects in chemical flooding research

Title	Chemical loss	Mobility control	Reservoir heterogeneity.	Salinity/ temperature	Recovery mechanisms
Interactions of Structurally Modified Surfactants with Reservoir Minerals:Calorimetric, Spectroscopic, and Electrokinetic Study (Columbia University)	X				
Tertiary Oil Recovery Research at the University of Texas (University of Texas at Austin)	X			X	X
Surfactant-Enhanced Volumetric Sweep Efficiency (University of Oklahoma)		X			
Enhanced Oil Recovery Through In Situ Generated Surfactants Augmented By Chemical Injection (Illinois Institute of Technology)					X
Investigation of the Application of Gelled Polymer Systems for Permeability Modification in Petroleum Reservoirs (University of Kansas)		X			
Associative Polymers for Mobility Control in Enhanced Oil Recovery (University of Southern Miss.)		X			
Fluid Diversion and Sweep Improvement with Chemical Gels in Oil Recovery Processes (New Mexico Institute of Mining and Technology)		X			
Oil Recovery Enhancement from Fractured, Low-Permeability Reservoirs (Texas A & M University)			X		
Development of Improved Surfactant Flooding Methods (NIPER)	X	X		X	X
Development of Improved Alkaline Flooding Methods (NIPER)	X			X	X
Development of Improved Mobility Control Methods (NIPER)		X			

The University of Texas at Austin is doing research on the general area of optimizing surfactant structures. In one sub-project, thermodynamic modeling of microemulsions uses dispersion free energy and energy of bending of the droplet interface. The latter is being measured by an ultrafiltration technique and will be related to surfactant structure. In another sub-project, the theory of diffusion and electric transport in microemulsions is being developed as a tool for evaluating drop-drop interaction and its dependence on surfactant structure. Diffusion and conductivity measurements are being supplemented by quasilinear light scattering and permittivity measurements. The methods are used to probe the microdistribution of alcohol and will be applied to the interaction of surfactants and carbon dioxide. In a third sub-project, adsorption on titanium oxide (as a model surface) was measured along with pH and zeta potential, to test a theory based on the structure of the electric double layer.

Finally, ellipsometric measurements were used to measure film thickness on solid surfaces and to check theories of disjoining pressure and the transition zone between a thin film and a capillary meniscus.

Achievements:

1. The thermodynamic theory was fairly successful in modeling solubilization, drop size distribution, and composition gradients in a gravitational field.

2. It was found that alcohol accumulates primarily on the surface of microemulsion droplets, in this way expanding the range of distribution of surfactant, and preventing formation of condensed phases by reduction of interaction between surfactant molecules.

This project is successor to a program that was very productive over a period of 18 years, with the following notable achievements:

1. Development of the spinning drop interfacial tensiometer.

2. Introduction of the concept of equivalent alkane carbon number of crude oils.

3. Development of the systematics of surfactant optimization, as related to alkane carbon number and salinity, using equations with terms identifiable with the hydrophobic and hydrophilic portions of the molecule.

4. Synthesized a variety of monoisomeric surfactants (anionic), to identify the effect of structure on salt and temperature tolerance, and on adsorption.

5. Characterized the relations among phase behavior, low interfacial tension and solubilization.

6. Demonstrated the role of spontaneous emulsification in mobilization of oil, independent of capillary number effects.

7. Successfully modeled mixed-surfactant adsorption isotherms by first modeling formation of mixed micelles in bulk and on the surface.

8. Measured and correlated simultaneous adsorption of surfactant, alcohol, and oil from microemulsions.

9. Modeled the transport of surfactant in flow through pores by applying the theory of chromatographic wave fronts. (Basis of the current project at the University of Oklahoma.)

The University of Oklahoma had a 3-year project on improving sweep efficiency by precipitation of surfactants. Sequential injection of a cationic and an anionic surfactant with different chromatographic properties was designed, so that they interact to form precipitates (or coacervates) that block flow in high-permeability zones. The first step was mapping and modeling of precipitation, micellization, adsorption, and coacervation of mixtures as a function of pH, temperature, ionic strength, and surfactant structure. The second step was designing and modeling the requirements for surfactant concentration and volumes of the two slugs and the brine spacer.

Achievements:

The technical feasibility was demonstrated theoretically and in the laboratory. Under favorable conditions, only dilute surfactant slugs are needed, and the process works automatically in selecting the high-permeability zones.

At the Illinois Institute of Technology, a project of long duration has dealt with the role of emulsification and coalescence for oil bank formation in surfactant and alkaline flooding. A wide variety of techniques has been applied:

1. Bottle tests of emulsion and foam stability

2. Phase behavior and partitioning

3. Still and moving photomicrography of wettability and oil blob movement in pores

4. Microwave and gamma-ray adsorption measurements of movement of oil banks in porous media

5. Microwave interferometric dielectrometry of emulsion type

6. Measurement of dynamic interfacial properties: transient interfacial tensions, shear and dilational interfacial viscosities (water-oil and water-air), and elasticities

7. Optical measurements of thin aqueous films in oil, air, and on solid surfaces - drainage and wettability effects

8. Electrokinetic properties correlated with wettability and emulsion stability

Instrumentation for many of the techniques was designed on the project. Extensive mathematical work was done to permit analysis of the data and to develop models for simulation of the results.

Achievements:

1. Movement of the oil bank and recovery were correlated with emulsification and rapid coalescence - the latter dependent on low interfacial viscosity.

2. Stable emulsions were identified as a major cause of failure of the Mobil-Salem pilot.

3. Demonstration that the formation of structures (liquid crystals, micelles, and pre-micellar aggregates) was shown to increase interfacial viscosities, slow thinning of liquid films, and increase stability of emulsions and foams.

4. Demonstration that water films at a solid surface, which affect wettability, have elastic properties very different from those of free films, and that the difference increases with decreasing thickness.

5. Finding that emulsion stability is minimal at the low-salt end of the 3-phase region, if there is one.

6. Showing that there is an optimum pH in alkaline flooding (depending on other compositional parameters) at which the oil acids are half ionized.

7. Development of interference dielectrometry and interpretation by a percolation model, which allows on-line measurement of emulsion, type and water content.

8. Creation of a successful fractional flow model (based on a successful model for dynamic interfacial tension), which allows evaluation of design factors for mobility control, the addition of surfactants to alkali, and the role of adsorption.

The University of Kansas has made a study of permeability modification by gelled polymer with three facets:

1. Description of gelling systems. Use of xanthan and polyacrylamide systems, with aluminum or chromium in some form (Cr[VI] + redox, Cr [III] as nitrate, a basic oligomer, or a neutral ethylene diamine). The study included kinetics, gel strength, and stability, as a function of chromium concentration, degree of hydrolysis, pH, and shear conditions.

2. Gelation in porous media. The buildup of flow resistance, and it's spatial distribution, as a function of flow rate and permeability. The effect of swelling and shrinking (syneresis). Adsorption of Al and Cr.

3. Modeling of in situ gelation.

Achievements:

1. Developed improved gelling systems, including one effective at pH 7.

2. Clarified the difference between gelation effects in bulk and in pores. Flow resistance was found to be based on a different mechanism than bulk gelation, and is highly localized, so the kinetics and stability (swelling/syneresis) cannot be directly predicted from bottle tests. However, the flow resistance was successfully modeled.

The New Mexico Petroleum Recovery Research Center is executing a systematic study of properties of gels formed from materials of various chemical nature, as affected by pH, temperature, permeability, and lithology. They have applied mathematical analysis to problem of zone isolation and gel placement.

Achievements:

It was demonstrated that zone isolation is essential in most cases. Residual resistance factor was shown to have a distinct dependence on flow rate.

The University of Minnesota has conducted a very extensive program of basic research, integrating physics, chemistry, geology, applied mathematics, and engineering science. Experimental techniques used have been: phase studies, measurements of interfacial tension, capillary pressure, fluid flow, electrical conductance (including complex dielectric properties), and diffusion; X-ray techniques; neutron and light scattering; electron microscopy (transmission and scanning); and spin echo pulsed field gradient NMR. The group has two supercomputers, a Cray-1 and a CDC Cyber 205, used for process simulation, modeling of fluid properties and wetting by means of thermodynamics and molecular theory (equilibrium and dynamic), and flow and transport phenomena, including frontal instabilities.

Achievements:

1. Designed and patented an improved spinning drop tensiometer with superior gyrostatic equilibrium and reduced temperature gradients.
2. Patented a cryo-electron microscope technique for visualizing fluid microstructures and the distribution of fluids in reservoir rock.
3. Applied imaging theory to the correct interpretation of polarizing optical microscopy of anisotropic media.
4. Devised an improved treatment of centrifugal data for determining capillary pressure. The new method permits use of longer samples.

5. Used capillary pressure data on natural sandstone at low saturation to determine the fractal dimension of pores.

6. Pioneered the concept of bicontinuous structure of microemulsions, and confirmed by a multifaceted experimental program.

7. Demonstrated and patented the favorable transport properties of vesicles formed by ultrasonication of surfactants solutions.

8. Developed successful theories - thermodynamic and molecular - for interfacial tension, phase behavior, wettability, and thin film behavior. In particular:

   - The importance of critical endpoints was highlighted.
   - Phase behavior was modeled continuously from "mere amphiphiles" (e.g., alcohols) to structure-forming materials (true surfactants).
   - Phase transitions were related to spontaneous curvature of the oil/water interface.
   - A new technique of calculating chemical potentials was developed that saves computer time by a factor of 200.
   - A quantitative difference was identified in wettability/thin-film behavior between solutions and microemulsions.

9. Devised a statistical network to represent porous media – emphasizing pore shape and connectedness as principal parameters – that allowed for tractable but accurate modeling of conductivity, dispersion, and relative permeability.

10. Modeled viscous fingering by methods developed for simulation of diffusion-limited aggregation processes.

11. Developed a tractable molecular theory of transport in pores, taking into account the strong inhomogeneities occurring in fluids near solid surfaces. Similarly, made successful modifications of electric double layer phenomena at the oil/water interface.

12. Calculated conductivity, diffusivity, and dielectric properties of random binary composites. Found that dynamic structural fluctuations, which become more pronounced with low molecular weight materials, have effects that are separate from true percolation processes.

For about 10 years, the University of Southern Mississippi carried out a program of synthesis and evaluation of polymers for mobility control in EOR. Most work was done on copolymers and terpolymers. Monomers in early investigations included dextran, vinyl-pyrrolidone, and sulfoethyl methacrylate, but more recent work focused on the following:

acrylamide (AM)
N-substituted alkyl or alkyl-aryl acrylamides (RAM)
2-acrylamido 2- methyl propane [CH_2=CH-CO-NH-CMe_2-CH_2-] with various substituents:

- sodium sulfonate [-SO_3Na] (NaAMPS), anionic
- dimethyl ammonium chloride [-NMe_2H-Cl] (AMPDAC), cationic

- sodium carboxylate [-C=O-OH-Na], (acrylamido methyl butanoate, NaAMB), anionic
- dimethyl ammonium propane sulfonate [$C^{+}Me_2$-$(CH_2)_3$-SO_3-] (AMPDAPS), zwitterionic
- acetone {C=O-Me}(N-1,1 dimethyl-3-oxobutyl acrylamide, DAAM, nonionic)
- N-(1,1 dimethyl-3-oxobutyl)-N-(n-propyl) acrylamide, PDAAM), a nonionic relative

Parameters investigated, in addition to structure, were: molecular weight (and its distribution), ionic environment (salinity, calcium, pH), and temperature. Techniques applied were: size exclusion chromatography (SEC), C^{13}NMR, low-angle laser light scattering, dynamic light scattering, fluorescence probing, conductimetry, turbidity measurement, and rheology. Theoretical work included modeling of SEC for interpretation of results, and modeling of rheological behavior as a guide to design of molecular structure.

Achievements:

Improvements in SEC included "shrinking" molecules by solvents, development of new packing materials, and multiple detectors. A preparative SEC was constructed, capable of fractionation by molecular size up to 3500 A.

Polymers found to have superior properties were:

1. Co-polymers of AAM/NaAMB were patented and adopted for development by Suntech. These are fully calcium tolerant.

2. Co-polymers of AM/RAM were patented and tested by Exxon and Dow. Solubility problems were ameliorated by terpolymerization with an ionic constituent such as acrylate (best), NaAMPS, or NaAMB.

Both of these products exhibited cooperative molecular aggregation through hydrophobic interaction. This was controlled in the case of AM/RAM by the chain size. The association was reversible, so the product is not expected to cause injectivity problems or exhibit irreversible shear degradation.

3. Ampholytic co-polymers NaAMPS/AMPDAC, which have a viscosity that is low in water and shows a strong increase with increasing salinity. The viscosity increase can be markedly augmented by terpolymerization with AM. The AM/NaAMB/APDAC terpolymer is strongly crosslinked and insoluble in water.

4. PDAAM has strong emulsifying capabilities, and shows promise of combining surfactancy and mobility control into the same molecule.

When <u>NIPER</u> was established in 1983, it continued research efforts in various areas of chemical flooding .

Experimental techniques employed have been interfacial tension measurements, observations of phase behavior (including phase inversion temperatures by conductimetry), adsorption measurements (including chromatography), foam generation, coreflood and slim tube tests for oil recovery and chemical transmission, bulk and microscopic observations of emulsification and coalescence, viscometry, flow resistance measurements, and calorimetry (dilution and adsorption).

Surfactants studied for oil recovery potential included disulfonates, biosurfactants, carboxymethylated ethoxylates (CME), amine oxides, alpha-olefin sulfonates (AOS), commercial sulfonates (RSO_3), and an ether sulfate ($ROROSO_3$). For calorimetric studies, the list included cationic trimethylammonium bromides (TAB), a nonionic polyethoxylated alkyl phenol, and synthetic sulfonates.

Alkanes and crude oils with various acid numbers were utilized.

Alkalis tested for reactivity with minerals were sodium hydroxide, sodium metasilicate, sodium carbonate, and sodium bicarbonate. Oil recovery tests primarily employed mixtures of the carbonates and sodium orthophosphate. Minerals tested were silica, kaolinite, montmorillonite, chlorite, four less common aluminosilicates, two reservoir sandstones from California, and two from China.

A significant portion of the work has been design of chemical recovery systems for specific reservoirs for clients or those designated by the DOE.

Investigations included:

- Adsorption, extent and energetics, studied as a function of surfactant type, solid wettability, salt and alcohol content, and temperature.
- Heats of dilution (principally to characterizes micellization), measured on decyl TAB as a function of alcohol content and temperature. (The alcohol, n-butyl, was also measured by itself.) Critical micelle concentrations (CMC) were evaluated for CME's and their blends with an AOS.
- Oil recovery with mixed agents: blends of surfactants CME's and AOS, or RSO_3 and $ROROSO_3$; surfactants and alkalis (all with polymer). Attention was paid to injection strategies for the surfactant-alkali-polymer process.
- Emulsification/coalescence phenomena were studied in dilute surfactant-alkali media.
- Rheology of polymers: viscous and elastic properties, and flow through porous media.

- Gelled polymers: The effect of shear rate and degree of hydrolysis on the kinetics of gelation and the strength of gels. Low molecular weight polymers were crosslinked for evaluation as ordinary mobility control agents.

Achievements:

1. It was found that the CMC increases strongly at high temperatures, and the micellization region becomes more diffuse. This can be counteracted by the presence of salt, which lowers CMC and narrows the region. A low CMC is preferable, as it reduces chromatographic separation of mixtures.

2. The heat of adsorption was found to increase with both temperature and salinity.

3. Two thermodynamic models of adsorption were successful in matching the extent and energetics of adsorption, including 3-component systems.

4. Differences in the temperature response of adsorption between oil-wet and water-wet surfaces supported the idea of different mechanisms (electrostatic and hydrophobic).

5. Amine oxides were found to function both as surfactants and mobility control agents.

6. CME's were effective surfactants at high temperature and salinity with alkanes, but were less effective with crude oils, and had serious problems with adsorption and phase trapping.

7. The synergy between alkali and surfactant was clarified, in that alkalis promote more rapid reduction of interfacial tension, surfactants maintain low values longer, and the combination enjoys both benefits.

8. The surfactant-alkali combination was shown to be effective even with very low-acid oils.

9. An automated instrument was developed for measuring phase inversion temperature.

10. A patent was granted on the method of oil recovery by sodium bicarbonate and surfactant. The pH of $NaHCO_3$ is low enough to avoid mineral reactions, but high enough to be enhanced by surfactant.

11. It was discovered that surfactants may form aggregates that plug low-permeability cores if the ionic strength of added alkali is too high.

12. It was found that with proper precautions, gelled polymers will reheal after being degraded by shear.

13. It was found that gradients in mobility are more stable with Newtonian thickeners than with pseudoplastic, but if viscoelastic effects are operative, fingering at an unfavorable mobility-ratio boundary is more severe with Newtonian fluids.

14. A gelled polymer simulator was developed for predicting oil recovery from polymer flood and gelled polymer treatments..

MICROBIAL ENHANCE OIL RECOVERY

DOE-sponsored research projects on microbial enhanced oil recovery (MEOR) are listed in table I-24. Most of the microbial technology research effort has been devoted to laboratory studies dealing with physical simulation of MEOR processes. One of the major constraints to MEOR technology has been the lack of a numerical simulator capable of adequately describing and predicting the MEOR processes both in the laboratory and in the field. During the 1980s, researchers at the University of Oklahoma and University of Southern California studied transport of several different types of bacteria to produce one-dimensional mathematical models. It became apparent that microbial transport in porous media was an extremely complex phenomenon that required laboratory and field data to model adequately. Although several attempts have been made to modify existing reservoir simulators to describe microbial processes, no model has yet fully incorporated all of the complex phenomena that are believed to be important. Also, no model has integrated laboratory and field data for microbial transport processes. An accurate reservoir simulator for MEOR methods can best be developed through an integrated program of acquisition of laboratory and field data with the feedback loop being the reservoir simulation model.

Four of the five DOE-sponsored microbial technology research projects that deal with laboratory simulation are using the same microorganism, *Bacillus licheniformis*, strain JF-2, first isolated by the University of Oklahoma (Jenneman et al., 1983). This microbe has been used by NIPER in a consortium of bacteria for the first DOE-sponsored microbial-enhanced waterflood field pilot (Bryant et al. 1990a, 1990b). Other laboratories that are conducting the same types of experiments using JF-2 include Idaho National Engineering Laboratory and the University of Texas. There appears to be some duplication of effort since several of the same types of microbial coreflooding experiments are being conducted with JF-2. However, it has been found that different results are being obtained even though the same microbial species is being used (Thomas, 1990). The fifth project deals with simulation of polymer-producing microorganisms, and experiments are being conducted with *Leuconostoc*, a species that has been used exclusively in Canada for permeability modification field pilots (Jack, 1990). The project was only recently initiated, and no published information is available.

Five of the 12 projects were initiated in 1990. Thus, little information has been published regarding the project by Mississippi State University. It is unclear what types of interactions they are going to be investigating. Mainly, they will be studying indigenous microbial flora from several different reservoirs. The project by Fairleigh Dickinson Laboratory, "Development of Luminescent Bacteria as Tracers for Geological Reservoir Characterization," has been mainly a paper study to date, with no laboratory or field data reported. A study of MEOR processes for

TABLE I-24. - Selected DOE–sponsored projects in microbial EOR research

Title	Salinity/ temperature	Recovery mechanisms	Field tests	Nutrients
Effects of Selected Thermophilic Microorganisms on Crude Oils at Elevated Temperatures and Pressures (Brookhaven National Laboratories)	X			
Enhanced Oil Recovery and Applied Geoscience Research Program (Idaho National Engineering Laboratories)		X		
Microbial Field Pilot Study (University of Oklahoma)			X	
Microbial Enhancement of Oil Production From Carbonate Reservoirs (University of Oklahoma)		X		
Development of Improved Microbial Flooding Methods (NIPER)	X	X		X
Microbial-Enhanced Waterflooding Field Project (NIPER)			X	
Microbial Enhanced Oil Recovery Research (University of Texas at Austin)	X	X		
Quantification of Microbial Products and Their Effectiveness in Enhanced Oil Recovery (University of Oklahoma)	X	X		

TABLE I-24. - Selected DOE–sponsored projects in microbial EOR research–continued

Title	Salinity/ temperature	Recovery mechanisms	Field tests	Others
Polysaccharides and Bacterial Plugging (University of Michigan)		X		
New Microorganisms and Processes for MEOR (INJECTECH, Inc.)	X			
Study of the Interactions Between Microorganisms, Microbial By-Products, and Oil-Bearing Formation Materials (Mississippi State University)		X		
Development of Luminescent Bacteria as Tracers for Geological Reservoir Characterization (Fairleigh Dickinson Lab)				X

carbonate reservoirs is being conducted by the University of Oklahoma. This project should provide valuable information regarding applicability of microorganisms for carbonate reservoirs. However, applicability of MEOR in carbonate reservoirs could be limited by the fact that most have very low in permeabilities. Typically, a cut-off limit of 50 to 100 md sandstone permeability has been cited for microbial EOR processes (Bryant, 1990). Pore size distribution in carbonates could be much different from that in sandstone, and thus microorganisms may be applicable.

The study by Brookhaven National Laboratories regarding metabolism of microorganisms on crude oils is interesting, but probably has more of an impact on crude oil processing than enhanced oil recovery. Metabolism of microorganisms using crude oil as a nutrient is inherently too slow to have much of an impact on oil recovery, although for removal of metals and upgrading of crudes, this may be a feasible process. Lastly, the project by INJECTECH, Inc. investigates the use of bacteria that produce acids for rock dissolution. One of the species of bacteria they are using is *Thiobacillus*, a type of microorganism that can produce acid for limestone dissolution. Some of the constraints to this project will be the ability of the microorganisms to produce an adequate amount of acid under such limited nutrient conditions to effect permeability modification, and the fact that fairly permeable carbonate reservoirs would be the only candidates for the process.

Table I-25 lists accomplishments of DOE sponsored microbial projects. The University of Oklahoma and NIPER projects are the only two that have been continued to the present time. Of the 12 microbial technology projects sponsored by the DOE, half of them are university-based programs, two are contracted to private companies, and four projects are being conducted by national research laboratories. Only two of the 12 projects, one at NIPER and one at the University of Oklahoma, are performing field research. Reports from the NIPER field project (Bryant et al. 1990a, 1990b) indicate that one pilot has been completed and another field injection has been initiated. The original pilot from NIPER showed an increase of 13 to 20% in the affected area nearest the microbially-treated injection wells. Water-oil ratios on all wells near these injectors were decreased, while off-pattern wells showed an increase over the two and one-half year monitoring period. The expanded pilot (520 acres) was injected in June, 1990, and monitoring is continuing. Injection is pending in the University of Oklahoma project.

TABLE I-25. - Accomplishments from DOE-sponsored microbial technology projects

Developed non-pathogenic *Clostridium* species for use in single-well stimulation tests	Oklahoma State University
Conducted several single-well stimulation pilots using *Clostridium*	Oklahoma State University
Isolated and identified a novel bacterium that co-existed with sulfate-reducing bacteria from Wilmington field	Oklahoma State University
Isolated and characterized microbial species that could degrade polyacrylamide polymers used in EOR	Oklahoma State University
Isolated microbial species that produce biosurfactants and biopolymers for use in MEOR	University of Oklahoma
Demonstrated permeability reductions in porous media by microbial growth	University of Oklahoma
Developed a method to identify nitrous-oxide producing bacteria in reservoir brines that prevent growth of sulfate-reducing bacteria	University of Oklahoma
Designed and have begun an MEOR field pilot for injection of nutrient for stimulation of microbial growth to cause fluid diversion	University of Oklahoma
Demonstrated facilitated bacterial transport in porous media using certain chemical additives	University of Southern Calif.
Isolated a biosurfactant capable of reducing heavy oil viscosity by as much as 95%	University of Georgia
Developed protocols for evaluating microbial species in porous media for enhanced oil recovery	NIPER
Investigated long-term survival and interactions of sulfate-reducing bacteria with other injected and indigenous microbial populations in porous media	NIPER
Completed a microbial-enhanced waterflood field pilot and and began an expanded field pilot	NIPER
Developed 1-D and 3-D numerical simulators for MEOR processes	NIPER

THERMAL EOR

In the recently published DOE *Quarterly Progress Review of Contracts and Grants for EOR Research 63*, 9 thermal EOR related projects were identified. These projects together with the constraints addressed are listed in table I-26.

In Situ Combustion

The objectives of Union Carbide's in situ combustion program are to characterize the reservoir mechanisms that cause premature oxygen breakthrough and to develop tools to control them, while Stanford University's in situ program is focused on evaluating the effect of various reservoir parameters on in situ combustion performance. Union Carbide's in situ program has since been discontinued due to lack of industry support for the in situ combustion process.

Steam-Foam Research

The work at the University of California and University of Southern California has been focused on elucidating the mechanism of foam flow through porous media. While researchers at the University of California are investigating the effect of trapped gas on foam mobility, University of Southern California researchers are studying the effects of pregenerated foams as well as hysteresis effects on foam flow.

The work at Stanford University has included the investigation of transient foam flow behavior in porous media as well as the characterization of foaming surfactants at steamflood conditions. An X-ray CAT scanner is being used to study foam flow behavior in porous media. The researchers at NIPER has focused their attention on evaluating the effectiveness of commercial surfactants in diverting steam in the presence and absence of alkaline additives and to determine the conditions under which these surfactants perform best.

Vapor Liquid Flow in Porous Media

This project at the University of Southern California strives to understand the displacement and flow properties of fluids involving phase change (condensation-evaporation) in porous media using both physical and mathematical models.

Theoretical Modeling of Foam Flow in Porous Media

The objective of this research at the University of Southern California is to develop a theoretical model to predict the behavior of foam flow in porous media. In the development of the model, it is assumed that the foam will exhibit non-Newtonian flow characteristics (power-law fluid behavior) in porous media.

TABLE I-26. - Selected DOE-sponsored projects in thermal EOR research

Title	Reservoir Heterogeneity.	Gravity Override/ Mobility Control	Recovery Mechanism	Field* Problems	Others
Electromagnetic Sensing of Enhanced Oil Recovery (Lawrence Livermore National Laboratories)					X
Development of Methods for Controlling Premature Oxygen Breakthrough During Fireflooding (Union Carbide Corp.)	X				
Chemical Additives for Improving Steamflood Performance (University of Southern California)		X	X		
Thermal Processes for Light Oil Recovery (NIPER)		X	X		
Thermal Processes for Heavy Oil Recovery (NIPER)		X	X		
Mechanisms of Mobility Control with Foams (Lawrence Berkeley Laboratory, University of California))		X			
Innovative Drilling Completion System (Petrolphysics, Inc.)				X	
Research on Oil Recovery Mechanisms in Heavy Oil Reservoirs (Stanford University)	X	X	X	X	
Feasibility Study of Heavy Oil Recovery in the Mid-Continent Region (NIPER)					X

* Field problems include downhole completion, steam generation, and steam-quality problems.

Assessment of U.S. Heavy Oil Resources

The objectives of this feasibility study being conducted at NIPER are to develop a data base of the known heavy oil resources in the lower 48 states; screen this resource for potential thermal recovery applications; and to evaluate the various economic facets of thermal processes that may impact on the expansion of steamflooding outside California.

Numerical Thermal Simulator Development

The objective of this research at NIPER was to develop a steamflood simulator that is capable of running on a personal computer and that can be used by independent operators as a preliminary steamflood design tool. The project has been completed.

Thermal EOR Technology Transfer to Small Independents

The purpose of this NIPER project is to develop a comprehensive report on steamflood operations and practices and for small independent operators who are interested in steamfloods. This report is designed to help small operators in undertaking feasibility studies and to work with consultants, engineers, and equipment vendors.

Light Oil Steamflood Studies

The objectives of this NIPER project are to improve the understanding of the basic mechanisms responsible for the improvement of light oil production using steam and to use that understanding for accelerating the development of this production technology.

Innovative Drilling and Completion Technique for Thermal EOR

The principal objectives of this Petrolphysics project are to place multiple horizontal radial wells in a heavy oil reservoir and to demonstrate that the wells can be used either as steamflood injectors or as cyclic steam producers. Another objective of the project is to develop effective completion technology for horizontal steam wells. The project has since been successfully completed and the preliminary results indicate that a horizontal well may have doubled the productive capacity of a typical vertical well in the same lease.

Development of Steamfront Tracking Tools

The objective of this work at Lawrence Livermore National Laboratories is to monitor in situ changes in the electrical conductivity in a heavy oil reservoir subject to steamflood. The ultimate goal of this project is to develop practical tools for monitoring the propagation of a steamfront during an ongoing steamflood. Cross-borehole electromagnetic induction is being used to provide an image of electrical conductivity changes associated with an encroaching steamfront.

Discussion

Except for the research conducted at the University of California, all other DOE sponsored thermal EOR research has practical implications and fits into DOE's near-term research strategy. The UC research is more basic in nature and addresses DOE's long-term research objectives. It is suggested that the research needs addressed in this report be given careful consideration because they represent industry's current needs. A partial list of achievements of the DOE thermal EOR projects are listed in table I-27.

TABLE I-27. - Selected achievements of DOE thermal EOR projects

Developed a semianalytical steamflood predictive model to predict accurately the reservoir response to steam injection.	Stanford University Petroleum Research Institute (SUPRI)
Developed an analytical model to predict the steady-state homogeneous flow of fluid into a well through perforations.	SUPRI
Developed a correlation to predict two phase relative permeabilities from centrifuge capillary pressure data.	SUPRI
Developed a theoretical model to predict the radial transport of reactive tracers in porous media under conditions of tracer adsorption, nonuniform convection, and variable dispersion coefficient.	SUPRI
Developed composite reservoir well testing techniques to analyze well test data from a variety of steam injection projects, geothermal reservoirs and acidization projects.	SUPRI
Developed a 3-D laboratory physical model to elucidate steam-foam oil recovery mechanisms using an X-ray cat scanner.	SUPRI
Developed procedures to screen surfactants for use as steam foamer.	SUPRI
Developed and patented a novel steamflood process to recover light oils.	NIPER

TABLE I-27. - Selected achievements of DOE thermal EOR projects (Continued)

Developed a high pressure 2-D steamflood physical model to study gravity override and viscous fingering phenomena in steamflood process.	NIPER
Developed a personal computer based compositional steamflood simulator to study steamflood performance in laboratory physical models.	NIPER
Developed laboratory techniques to investigate the effectiveness of mobility control and diverting agents in diverting steam from a zone of high-permeability to a low-permeability zone.	NIPER
Developed techniques to measure the capillary pressures of consolidated and unconsolidated cores at elevated temperatures.	NIPER
Developed a cross borehole electromagnetic induction tool to monitor the propagation of a steam front during an ongoing steamflood.	Lawrence Livermore National Laboratories
Demonstrated techniques to drill and complete horizontal boreholes for steam injection process.	Petrolphysics, Inc.

GEOSCIENCE

In the recently published DOE *Quarterly Progress Review of Contracts and Grants for EOR Research 62* , 20 projects on geoscience research were identified. These projects are listed in table I-28. Five of these projects are on geophysical research, nine are on reservoir characterization of which three are also collecting data for input into TORIS, four are on multiphase flow in porous media, two are on data base development, and one is on geochemistry.

Geophysical Research

Projects at Los Alamos National Laboratories, Lawrence Livermore National Laboratories, and Colorado School of Mines are devoted to enhancing the imaging of interwell formations through improvement in interwell seismic tomography, whereas a University of California project aims at correlating seismic and electrical properties with pore topology, and rock-fluid and fluid properties. The Los Alamos project is developing a chemically powered seismic source that has the characteristics of high seismic frequency, high energy, high firing rate, and low cost.

Lawrence Livermore is field testing seismic tomography and high-frequency electromagnetic tomography in heavy oil sands.

Blackhawk Geosciences, Inc. is striving to improve the resolution of two-dimensional subsurface imaging using transient electromagnetic data for reservoir characterization.

Sandia National Laboratories is working to develop a method for tracking steamfronts in steamflooding by measuring the resistivity change in a reservoir. Both surface electric potential and controlled source audio magnetotellurics are being investigated.

Multiphase Flow Through Porous Media Research

Research projects at Texas A & M University and NIPER are using NMRI and CT to study multiphase flow in porous media. Whereas the Texas A &M research group is working with foam flow, the NIPER team studies microbial EOR, chemical EOR, and gas EOR with these tools. NIPER researchers are also using X-ray and microwave instrument to measure relative permeability and to study the effect of various physical parameters on the relative rate of flow of different phases. The Pennsylvania State University team performs research to correlate pore scale rock properties with wettability, capillary pressure, and other rock-fluid properties. A part of the work at University of California has also attempted to correlate transport properties of fluid in porous media with pore structure and pore network.

Reservoir Characterization

Research teams at NIPER, Geological Survey of Alabama, and Bureau of Economic Geology, University of Texas at Austin, are developing method to quantify flow parameters and flow units in subsurface reservoirs with the assistance of detailed data from outcrops. Conventional geologic methods and geostatistics are being used. The UT work is focused on carbonate reservoirs; the Alabama work is on reservoirs in Porelan Basins and those typical of the Jurassic Smackover formation, and the NIPER work is on shore line barrier systems. Another group at the UT Petroleum Engineering Department is developing geostatistical and mathematical methods to synthesize petrophysical and geological data to obtain parameters for reservoir simulation. The NIPER team is also integrating engineering techniques with geologic and geophysical methods to better model the reservoirs. The emphasis being to generate useful information for reservoir characterization based on tradition and available production and log information. The NIPER imaging analysis project is designed to study multiphase flow and rock/fluid interactions at pore and core scales using CT and nuclear magnetic resonance imaging techniques.

TABLE I-28. - Selected DOE-sponsored projects in geoscience research

Title	Data Sources/ data bases	Processes	Model construction	Others
Petroleum Geochemistry (Lawrence Livermore National Laboratories)				X
Advanced Seismic Geodiagnostics-Borehole Acoustic Source (Los Alamos National Laboratories)	X			
An Experimental and Theoretical Study to Relate Uncommon Rock-Fluid Properties to Oil Recovery (Pennsylvania State University)		X		X
Natural Resources Information System for the State of Oklahoma (Oklahoma Geological Survey, University of Oklahoma)	X			
Development of Nuclear Magnetic Resonance Imaging/Spectroscopy for Improved Petroleum Recovery (Texas A & M University)	X			
Geophysical and Transport Properties of Reservoir Rocks (University of California)	X			
In Situ Stress and Fracture Permeability: A Cooperative DOE-Industry Research Program (Sandia National Laboratories)				X
Characterization of Facies and Permeability Patterns in Carbonate Reservoirs Based on Outcrop Analogs (Bureau of Economic Geology, University of Texas at Austin)	X		X	
Imaging Techniques Applied to the Study of Fluids in Porous Media (NIPER)	X	X		X

TABLE I-28. - Selected DOE-sponsored projects in geoscience research–continued

Title	Data Sources/ data bases	Processes	Model construction
Laboratory Modeling and Field Development of Borehole Seismic Imaging Techniques Using Seismic Wavefield Measurement (Colorado School of Mines)	X		
Characterization of Reservoir Rocks and Fluids by Surface Electromagnetic Transient Methods (Blackhawk Geosciences, Inc.)	X		
Characterization of Sandstone Heterogeneity in Carboniferous Reservoirs for Increased Recovery of Oil and Gas from Foreland Basins (Geological Survey of Alabama)	X	X	X
Establishment of an Oil and Gas Database for Increased Recovery and Characterization of Oil and Gas Carbonate Reservoir Heterogeneity (Geological Survey of Alabama)	X	X	X
Research on Improved and Enhanced Oil Recovery in Illinois Through Reservoir Characterization (Illinois Department of Energy and Natural Resources)	X	X	X
Depositional Sequence Analysis and Sedimentologic Modeling for Improved Prediction of Pennsylvanian Reservoirs (Kansas Geological Survey)	X		X
Geodiagnostics for Reservoir Heterogeneities and Process Mapping (Sandia National Laboratories)	X		
Characterization and Modification of Fluid Conductivity in Heterogeneous Reservoirs to Improve Sweep Efficiency (University of Michigan)	X	X	

TABLE I-28. - Selected DOE-sponsored projects in geoscience research–continued

Title	Data Sources/ data bases	Processes	Model construction
Characterization of Oil and Gas Reservoir Heterogeneity (University of Texas at Austin)	X	X	X
Reservoir Characterization and Enhanced Oil Recovery Research (University of Texas at Austin)		X	X
Analysis of Reservoir Heterogeneities Due to Shallowing-Upward Cycles in Carbonate Rocks of the Pennsylvanian Wahoo Limestone of Northeastern Alaska (University of Alaska)	X		
TORIS Research Support (NIPER)	X		
Three-Phase Relative Permeability (NIPER)	X		
Reservoir Assessment and Characterization (NIPER)	X	X	X

The University of Alaska project is developing a data base to characterize reservoir heterogeneities form small-scale shallowing upward cycles of limestone of northeastern Alaska.

The Kansas Geological Survey and the Illinois Department of Energy and Natural Resources projects are designed to help local operators and stimulate improved oil recovery projects by performing detailed reservoir description, identification of production problems, and proposing solutions to improve recovery. The Kansas project is also developing a three-dimensional process simulator to explain how the dynamic interaction of geological processes create the observed lithofacies, stratigraphy and shelf configuration.

Data Bases

The NIPER project is updating the DOE EOR Project Data Base, to provide information on EOR trends and to validate oil production modeling. The Oklahoma Geological Survey project is developing a computerized, centrally located library containing accurate, detailed oil and gas production and well history information.

Geochemistry

The Lawrence Livermore National Laboratories project is developing model of petroleum generation, expulsion, and destruction.

Table I-29 lists the achievements of DOE-sponsored projects in geoscience research.

TABLE I-29. - Achievements of DOE-sponsored projects in geoscience research

Data for 54 Smackover fields were collected for inclusion into the TORIS data base. Sixty-four Smackover field data files were recorded on tape and submitted to the Bartlesville Project Office.	Geological Survey of Alabama
Developed log analytical procedure for using pre-1950 electric log to predict porosity, water saturation, and permeability.	Illinois Department of Energy and Natural Resources
Designed, fabricated and tested a geoelectric simulation facility for surface electric potential experiments.	Sandia National Laboratories
Developed a downhole shearwave source for crosswell seismic measurement.	Sandia National Laboratories
Developed a borehole receiver for interwell seismic imaging.	Los Alamos National Laboratories

Table I-29. - Achievements of DOE-sponsored projects in geoscience research (Continued)

Demonstrated the capability of cross-borehole seismic and high-frequency electromagnetic tomographic method in mapping steamed zone, and migration of steam and heat in the reservoir.	Lawrence Livermore National Laboratories
Developed method to interpret electromagnetic data collected through steel casing	Lawrence Livermore National Laboratories
Modified UTChem to incorporate the capability of analyzing single well tracer tests with drift.	University of Texas at Austin
Developed a procedure for deriving effective/pseudo relative permeabilities for viscously dominated flow in crossbed sands.	University of Texas at Austin
Modified a geochemical model in include partial equilibrium reaction in modeling the diagenesis in carbonate reservoir.	University of Texas at Austin
Demonstrated that in a deltaic reservoir the average permeabilities are greatest in the fluvial rocks, intermediate in shoreface facies and lowest in bioturbated facies also the variation in permeabilities is greatest in fluvial facies.	University of Texas at Austin
Showed that for the San Andres formation although the mean permeability agrees poorly between subsurface and outcrop. Other statistical measures, such as distribution type, and variogram range show good agreement.	University of Texas at Austin
Developed procedure to calculate core porosity and permeability based on computerized image analysis of thin section images.	NIPER
Developed thin slab rock micromodel techniques for observing oil, water, and gas displacements and spatial distributions within real rock pores.	NIPER
Converted a NMR spectrometer to a dual phase (oil and water) NMR imaging system with resolution of 50 microns.	NIPER
Developed CT scanner method to determine porosity and permeability spatial distribution and to study fluid flow behavior and spatial fluid saturation distributions at whole core scale.	NIPER

Table I-29. - Achievements of DOE-sponsored projects in geoscience research (Continued)

Developed relationships among petrophysical, petrographical, fluid, rock-fluid characteristics, electrical properties and relative permeabilities.	NIPER
Constructed and automated a multiphase relative permeability apparatus with capabilities to measure oil and water saturation under continuous flow conditions.	NIPER
Modified and automated a high-speed centrifuge for wettability measurements for large cores of high permeability.	NIPER
Developed an integrative methodology for characterization of Barrier Island reservoirs.	NIPER
Developed a quantitative geological-engineering model for Bell Creek field.	NIPER
Developed novel application of engineering and geostatistical techniques for delineating reservoir heterogeneities.	NIPER
Developed a simple, economic, and safe core-mounting method for dispersity determination.	University of Oklahoma

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CHAPTER 13
TECHNOLOGY TRANSPER

By Dwight. L. Dauben

A critical component in the application of EOR methods is the transfer of information to the producers who need the technology. The purpose of this discussion is to identify the methods by which complicated and constantly evolving EOR and related technology can be transferred to oil producers.

An underlying factor in the transfer of technology is the financial attractiveness of a proposed EOR project. Operators will have greater incentive to search for and to adapt new technology if the result is the implementation of an EOR project which will bring a significant financial return. Conversely, the best of technology transfer programs will be ineffective if the operator does not anticipate reasonable profits.

A key reference used for this discussion is the study conducted by the Interstate Oil Compact Commission in 1990 (IOCC, 1990). It will be subsequently referred to as the IOCC study.

IDENTIFICATION OF KEY PRODUCERS FOR TECHNOLOGY TRANSFER

A major goal is the development of a technology transfer program which would have a significant impact in the application of EOR methods to increase the domestic production. No group of producers should be excluded from a federally sponsored technology transfer program. However, it is important to target a particular class of companies so that available funds will have their greatest impact.

One criterion is the size of the oil producing company. The IOCC study lists the following breakout of domestic production by producer group for 1987.

GROUP	NUMBER OF PRODUCERS	% OF PRODUCTION
I (>1.5MMB/Y)	1426	83
II (>0.4MMB/Y and <1.5MMB/Y)	1748	7
III (<0.4MMB/Y)	19935	10

This analysis shows that Group I, constituting only 6% of the producers, is responsible for 83% of the total production. Although changes have occurred within recent years, it is anticipated that a similar analysis would be reached for 1991 production. This analysis indicates that an EOR technology transfer program would have the greatest potential for improved recovery with the larger producers. Oil recovery potential is the greatest since EOR processes work more effectively when there is a significant amount of mobile oil saturation. These companies are comprised of the majors and large independents.

A second criterion is the number of wells which face the risk of abandonment. Once abandoned, the potential for additional oil is permanently lost since economics usually prevent the re-entry of old wells or the drilling of new ones (Biglarbigi et al., 1990). Although the numbers of associated wells in the above table are not available, the largest number of well abandonments will be in Group III. This group is comprised of a large number of small independents. Group II companies would also have a large, but proportionately fewer, number of well abandonments within the next few years.

A third criterion is the resources which are currently available to the company. The conventional wisdom is that the major companies have all of the needed resources by virtue of their large staffs, in-house research and technical service facilities, and good access to information sources. This presumption is questioned on the basis of the large staff reductions which have occurred in recent years and the conclusion from Part II of this report that about one-third of previous EOR projects were greatly impacted by the failure to use state-of-the-art technology. Major oil companies have been responsible for most of the previously conducted large EOR projects.

At the other extreme, the small independent has been very reluctant to undertake an EOR project. This reluctance has been based on a lack of technical knowledge, insufficient staff, and inadequate financial resources to provide the needed upfront capital and to assume the high degree of risk. There are some notable exceptions, but the overall impact of the small independent in EOR operations has been minimal. Even with improved technology transfer, it is likely that this group of producers will not have the financial resources to have a major impact on future EOR operations.

The larger independent oil companies are a key target based upon their need for the specialized technology and their availability of manpower and financial resources. These companies have been the most aggressive in developing domestic reserves. They have the resources for the exploration, development, and production of oil and gas from conventional resources. They do not have the manpower and financial resources of the majors. However, with proper financial incentives and an improved technology transfer program, it is anticipated that the large independents could have a major impact in developing future EOR projects for increased domestic production.

The conclusion is that a technology transfer program should be available for use by all producers regardless of size. However, it should be targeted for groups which best meets the need of the selected criteria. The larger companies should be targeted if the principal criteria is the recovery of the maximum amount of oil. The smaller companies should be selected if the principal criteria is to prevent the loss of oil reserves by the early abandonment of wells. It is our opinion that a mix of these criteria should be considered in a final analysis. Therefore, our recommendation is to target the technology transfer program to the majors and intermediate to larger independents.

EXISTING TECHNOLOGY TRANSFER METHODS

It is appropriate to review the methods which have been traditionally used to transfer technology to the independent and major oil producers. The strengths and weaknesses of these methods will be assessed, and judgements made on how a future EOR technology transfer program might best function. This information is based upon interviews with independent and major oil producers, as reported in the IOCC report.

Independent producers have relied principally on the following methods:

(1) Service Companies. Independents rely heavily on service companies for reservoir management information and for technology innovations. Major service companies such as Halliburton and Dowell-Schlumberger have access to their own research and development facilities and have ready access to information from other sources. Information is passed on to their clients as a part of their service. Independents also rely heavily on consulting engineers, geologists, and geophysicists. Information from these sources is required since the independent may have a limited number of staff and may not have knowledge in specialized technology areas.

(2) Professional Societies and Publications. Independents also rely heavily on technical information provided from professional societies and from publications. Organizations such as the Society of Petroleum Engineers and the American Association of Petroleum Geologists are typical of the professional societies. Independents benefit from attendance at local section meetings where technical

information is disseminated and discussed. Publications from these organizations and DOE are utilized, as well as publications such as the *Oil and Gas Journal*, *Oil Daily*, *Petroleum Engineer*, and *World Oil*.

State-sponsored extension programs have proved to be successful in Kansas and in New Mexico in assisting independent operators in applying advanced technology to their operations. Although successful, these programs have impacted only the independents within specific geographic regions of the country.

The University of Kansas Tertiary Oil Recovery Project (TORP) has been successful in focusing independents in improving oil recovery by using advanced waterflooding techniques. TORP's research efforts have focused on the use of polymers, particularly crosslinked polymer gels and sequential polymer crosslinking techniques. The TORP program has been particularly successful, due in major part to the focused nature of the program and cooperative approaches which have been used.

The New Mexico Petroleum Recovery Research Center (PRRC) is a state-sponsored center for improving oil and gas recovery. It is funded by the State of New Mexico, DOE, and by private industry. Its mission is to carry out basic research, disseminate the information to others, and assist operators in increasing recovery from specific fields. Like the TORP, PRRC has concentrated its efforts on the problems which are unique to the state which is supporting its efforts. This focus has been one of the reasons for its success.

Independents tend to rely on each other for solutions to reservoir and/or production related problems. There seems to be little communication with major oil companies or with any other organization which is conducting research. Thus, the independent has little direct access to the most recent innovations which are being developed. The more complex technology involved in EOR seems to be beyond the reach of many independents.

Major oil companies have somewhat different methods for the transfer of technology. The major methods include:

(1) Professional Societies and Publications. The majors acquire most of their technology from these sources. They tend to be very active in professional organizations and are the major contributors to the publications.

(2) Industry R & D Groups. Another important source of information for the majors is the in-house research and technical service organizations. The relationships between

operations and the research laboratories are normally strong and interactive. The in-house R & D facilities have traditionally provided a rich source of information which has helped the company to maintain an aggressive position with respect to their competition. The majors are also strong participants in "SPE Forums" which exchange views on specialized research areas. They also participate in industry-sponsored organizations such as the Completion Engineers Association (CEA) and the Reservoir and Recovery Forum (RRF).

(3) Service Companies. As for the independents, the majors rely heavily on service companies for providing the transfer of information. Such service companies include Halliburton and Dowell-Schlumberger, as well as companies providing data sources. The majors take full advantage of data sources which may be available on the computer from various service firms. They have the resources to store large amounts of information and to utilize data sources and expert systems for solving various problems. The majors depend much less heavily than the independents on consultants for the transfer of information.

(4) DOE R & D Programs. In spite of common perception, the survey conducted by IOCC indicates that majors have benefitted by DOE's R & D and university research program. DOE's research program has traditionally been in the category of long range and high risk. This strategy has been complementary and of value to the majors because of their emphasis on the short range resolution of problems. DOE's shift toward the shorter and mid-range research programs will undoubtedly impact its future working relationship with the majors, hopefully on the positive side. Establishment of the Oil Recovery Technology Partnership, a cooperative research venture between the Sandia and Los Alamos National Laboratories, oil companies, and research organizations, is also a move in the right direction towards effective and efficient technology transfer.

Overall, the majors have rich and varied resources for the transfer of technology. However, these capabilities have eroded to a degree over the past several years by the significant reduction of their staff.

PROPOSED METHODS FOR THE TRANSFER OF EOR TECHNOLOGY

Recommendations are provided to improve DOE's effectiveness in the transfer of EOR technology. The overall goal in the program should be to transfer the EOR technology in a cost-effective approach to achieve a maximum increase in domestic oil production. These recommendations are based in part on the findings of the IOCC study and in part on the results of this study. The following recommendations are made:

(1) Refocusing Current Research Programs. Perhaps the most effective approach in the transfer of technology is to ensure that DOE's research program is focused in the critical areas and addresses the needs of the operators which can most profitably use the technology. This refocusing of research is now underway to achieve compatibility with DOE's program of shifting emphasis from the long-term, high-risk to the shorter term research program designed to meet immediate needs. This program has been structured to meet specific short-term, intermediate, and long-term research needs. A well focused and pertinent research program will eventually be recognized by the industry and will have a better chance of acceptance.

(2) Targeting of Technology Transfer Efforts. DOE's technology transfer program should be made available to all companies regardless of size. However, it should be targeted toward a specific class of companies which could most effectively use the technology to increase domestic oil production and to prevent loss of reserves through early abandonment. The targeted companies should be the larger producers, made up principally of the medium-sized to larger independents but also some of the majors which no longer have strong R & D capabilities. The technology transfer program should strengthen the methods which have been traditionally successful and introduce ideas for more effective results.

(3) Strengthening of Existing Technology Transfer Programs. After a careful review of the effectiveness of current programs, steps should be taken to strengthen those programs which have historically been successful.

The previous approaches of disseminating information free of charge to producers through technical publications and software releases have been effective and should be continued. Examples of widely accepted DOE software include the EOR screening models used in the 1984 National Petroleum Council EOR study and the BOAST black oil simulator.

The biennial EOR symposium sponsored jointly by DOE and SPE, and the Reservoir Characterization and Microbial EOR symposia sponsored by DOE and NIPER are some of the more successful and effective means of transferring advanced oil recovery technologies to the petroleum industry.

DOE's initial workshop on EOR technology for deltaic reservoirs resulted in a good exchange of ideas on applicable technology. It was attended by a good cross section of personnel from DOE, major oil companies, and independent operators. It is recommended that such workshops continue, taking advantage of the feedback that is received for constructive improvement. In addition, the workshops can be structured on a smaller scale to allow a visiting expert to review technology in a specialized area, especially as it applies to the type of reservoirs which exist in the area. In such workshops, it is critical to use personnel who have a total grasp of the technology including the practical aspects. As discussed in Part II, operational problems represent a major cause for the failure of EOR projects. The use of the single criterion of reservoir type as a basis for a workshop is questioned, since it is only one of several important parameters required in considering EOR applicability. Other important criteria which control the type of process which applies include fluid properties (heavy versus light) and reservoir depth.

Continued DOE funding of state-supported institutions in Kansas and New Mexico is recommended on the basis of the success that they have achieved. Such organizations appear to have been effective in transferring technology to oil and gas producers within their geographic area. This concept could be extended to other state entities in other geographic areas. However, it is cautioned that over-reliance of this geographic-specific approach toward technology transfer may diminish the rich diversification of ideas and concepts that occurs when monitoring the progress of the industry as a whole. Some mix of a regional and industry-wide technology transfer program is probably optimal.

Additional short courses, workshops and field trips to EOR projects on advanced oil recovery technologies, similar to those sponsored by DOE, NIPER and regional independent oil producer associations on MEOR, should also be organized at regular intervals in various oil-producing regions.

(4) Introducing New Approaches for Technology Transfer. New approaches for improving technology transfer are recommended, taking advantage of the developments in communication which have occurred. Approaches which can be considered include the following.

One recommendation is to improve access to commercial publications through an on-line information service. As discussed above, both independents and majors rely heavily on published sources of information. This source provides a low-cost means of acquiring background information which might be pertinent to a particular field operation. On-line access to information would improve the ability of the operator to acquire information in specialized areas without the need for maintaining a large, in-house library. Many of the independents are located in areas which do not have convenient access to a library containing petroleum-related books and magazines. The University of Tulsa's Petroleum Abstracts is perhaps the prime example of a suitable data base of information. This data base can be currently accessed on-line, but it is not set up for low cost and routine use from remote locations. A DOE program should not compete with an existing service, but perhaps be structured so that current capabilities are enhanced. Specific proposals on such a program would be required.

A second approach which can be considered is the interactive teaching of specialized courses through video communication. The concept is that a well recognized expert will teach a course in a specialized area, with constant and interactive feedback with a group in a remote location. The advantage of this approach is that the class will have access to an expert who would otherwise not be available in his geographic area. The interactive capabilities allow everyone to participate fully in discussions in much the same way as a class with all participants physically present. The ability to implement such a program in practical terms is at the edge of the technology as it exists today, considering telecommunication costs and the locations of many oil field areas. With these near-term limitations in mind, it is recommended that such a program be investigated.

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CHAPTER 14
SUMMARY OF TECHNICAL CONSTRAINTS

CONSTRATINTS TO ACHIEVING NEAR-TERM GOALS OF THE AORPIP

One of the near-term goals in the Advanced Oil Recovery Program Implementation Plan (DOE, 1990) is to recover the additional 15 billion barrels of mobile oil that could be recovered with currently available proven technologies. The proven technologies, identified in the AORPIP as infill drilling, horizontal drilling, profile modification and polymer flooding, have to be transferred to the operators that do not as yet utilize them. In this chapter some constraints to achieving this goal will be summarized.

Chapters 6, 7 and 9 discussed the recent advances in technologies in polymer flooding, profile modification, and infill and horizontal drilling. Field projects in polymer flooding are also reviewed in Part II of this report. The technical constraints identified in these chapters are:-

Polymer Flooding

(1) Limited to reservoir salinity <18% NaCl, 1.5% $CaCl_2$

(2) Limited to reservoir temperature < 250°F (laboratory), field test up to 210°F

(3) Limited to permeability > 100 md

(4) Injectivity and propagation problems.

Profile Modification

(1) Limited to reservoir salinity < 10% NaCl, 10% $CaCl_2$

(2) Limited to reservoir temperature < 250°F.

(3) Implemented primarily in near well bore treatment

(4) Zone isolation often necessary to avoid damage to productive strata.

Infill Drilling

Technical constraint that are generally applicable cannot be identified. Constraints specific to certain reservoirs do exist, and can be overcome on an individual basis. For a project to be economic, proper reservoir characterization to identify the drilling site, and to locate potentially recoverable oil is a must.

Horizontal Drilling

The situation with horizontal drilling is similar to infill drilling, in that most constraints of the general area have been solved and limitations that are peculiar to a particular case have to be dealt with individually. An article in a recent *Oil and Gas Journal* went as far as declaring that "the only major factor that limit growth of horizontal wells is the lack of available drilling motor, survey equipment and experienced horizontal drilling personnel"(Moritis, 1991).

Because of the very fact that the technologies covered in these chapters have been selected in the AORPIP as proven technologies for near-term applications, it comes as no surprise that the technical constraints are minimal. The other possible constraints are financial, environmental and ignorance of some of the advantages of these technologies. The financial constraints are many; fluctuation in oil prices and recently slumping of the Nation's economy are two of the major factors. The environmental impact of this technology will be similar to the overall oil and gas industry, and therefore expansion in the usage of these technologies should not be limited by current environmental regulations. However, further tightening of the environmental laws - such as the proposal to classify all injection wells as class II wells - would be devastating to attempts to expand usage of these technologies.

It is expected that the major oil companies and large and medium independent operators have the knowledge regarding the advantages and the know how to apply these technologies. There is, however, a genuine need to transfer this information to the smaller independent operators. Transferring these technologies to small independent operators has the advantage of encouraging the expansion of their application. It has also the potential of preventing these operators from being swindled by unscrupulous individuals peddling and misrepresenting these technologies as recently reported by Advanced Recovery Week (1991) for horizontal drilling.

Technical Constraints to Demonstrating Cost-Effectiveness and Predictability to Advanced Technology

The mid-term goal of the AORPIP is to develop and transfer the best currently defined, advanced technologies to operators in the high priority reservoir classes. The mid-term strategy of the AORPIP is to resolve technological and economic uncertainties that limit application of advanced technologies through field work and supporting research. While field work will resolve some of these uncertainties, some of the constraints identified in earlier chapters have to be resolved through disciplined oriented research. The following list summarizes the constraints to some of the advanced recovery technologies identified in this study.

Gas EOR

(1) Reservoir heterogeneity

(2) Mobility control and reservoir conformance

(3) Incomplete mixing

(4) Lack of predictive capability

(5) Poor injectivity

(6) Corrosion problems with CO_2

Surfactant Flooding

(1) Reservoir heterogeneity

(2) Excessive chemical loss

(3) Coherence, stability and cost-effectiveness of surfactant slugs

(4) Limited to reservoir salinity < 20% NaCl

(5) Limited to reservoir temperature < 200°F

(6) Limited to permeability > 100 md

(7) Polymer propagation

Alkaline Flooding

(1) Limited range of applicable salinity

(2) High chemical consumption

(3) Brine incompatibility - precipitation

Microbial Enhanced Oil Recovery

(1) Nutrients for field application

(2) Lack of well-documented field tests

(3) Limited to reservoir temperature < 170°F

(4) Limited to reservoir salinity < 10% NaCl

(5) Insufficient basic understanding of the mechanisms of microbial technologies

Reservoir Characterization

(1) The complexity of the rock and fluid distributions even in the "simplest " reservoirs

(2) The inadequate amount of detailed information from even the most ambitiously sampled reservoir

(3) Scaling of properties from core or smaller scale to interwell scale

(4) Difficulties in interpreting seismic data in terms of rock and fluid properties

Thermal EOR

(1) Lower crude oil prices due to gravity, sulfur and heavy metal content

(2) Large front end investments and delayed responses

(3) Absence of cost-effective technology to upgrade low-quality, low-gravity crude into salable products

(4) Absence of cost-effective technology that permits the use of low-grade fuel such as coal, petroleum coke, high sulfur crude oil and brackish water to generate steam without violating the environmental regulations

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CHAPTER 15

SUMMARY OF RECOMMENDED RESEARCH NEEDS

This chapter summarizes the recommended areas of research that are needed to improve advanced oil recovery processes to achieve the near-, mid- and long-term goals of the AORPIP. These recommendations are made based on a review of the state of the art in the various advanced recovery technologies and a review of the field projects. Recommendations were not made for infill and horizontal well drilling because these technologies are being studied extensively by private industry, and rapid advancement is being achieved without encouragement or assistance by the Federal Government. However, application of horizontal wells in EOR has not been studied as extensively, so recommendation for research in this area are included in the discussion of the various EOR technologies.

GAS EOR

Areas of Needed Research

Near-term:

(1) Development of improved methods to predict phase behavior

(2) Development of a channel-block method for profile modification

(3) Development of improved prediction techniques for asphaltene precipitation

(4) Application of horizontal well technologies to gas EOR

Mid-term:

(1) Investigation of the effect of different scales of heterogeneity on recovery

(2) Investigation of the effect of incomplete mixing and phase behavior in porous media on recovery efficiency

(3) Development of improved compositional simulator for gas flooding

Long-term:

(1) Development of novel methods for gas mobility control

(2) Investigation of the fundamental properties of foam

(3) Study the characteristics of multiphase flow in porous media.

SURFACTANT FLOODING

Areas of Needed Research

Mid-term

(1) Improve reservoir evaluation and develop techniques to overcome reservoir heterogeneities

(2) Development of optimized (with respect to effectiveness, stability, and cost) surfactant EOR processes for application in high-salinity, high-temperature reservoirs

(3) More cost/benefit optimization should be studied for low-tension polymer floods

(4) The behavior of mixed surfactants should be explored more thoroughly

(5) Development of method to overcome surfactant-polymer incompatibility

Long-term

(1) A further understanding of the role of molecular structure should be developed to assist in the design of surfactants that can accommodate wider variations in salinity

(2) A comprehensive review of alternative surfactant types should be made to determine which (if any) deserve more extended testing and development of manufacturing procedures at reduced cost

(3) Various kinds of gradients (salinity, alcohol etc.) should be investigated. In particular, consideration should be given to combined gradients, as, for example, grading from an oil-rich composition with oil-soluble surfactant to a water-rich composition with water-soluble surfactant

ALKALINE FLOODING

Areas of Needed Research

Near-term

(1) The use of an extended "salinity requirement diagram" (two- or three-dimensional concentration scans of alkali, surfactant, and salt) to maximize oil mobilization

(2) Study of injection strategies (surfactant, alkali, polymer)

Mid-term

(1) More study of specific ion effects, and development of optimal mixtures of alkalis. Design of a means to stabilize silicate solutions at high values of SiO_2/Na_2O

(2) Investigation of the effects of alkalis on CMC, cloud point, and partitioning of surfactants; and on the mechanical entrapment of polymers

(3) Demonstrate technical feasibility of alkaline-surfactant-polymer flooding in well documented field pilots

MICROBIAL ENHANCED OIL RECOVERY

Areas of Needed Research

Near-term:

(1) Perform well documented field tests, especially in reservoir with substantial remaining oil saturation

(2) Development of low cost, consistent and readily available nutrients

(3) Development of profile modification and well stimulation methods

Mid-term:

(1) Development of salinity and temperature tolerant microbes

(2) Improvement of simulator for MEOR processes

Long-term:

(1) Improved understandings of recovery mechanisms for various microbial techniques

POLYMER FLOODING

Areas of Needed Research

Near-term

(1) Design of injection protocol. This includes using multiple polymer types in successive slugs or blends, and optimization of slug size

(2) Improved products for better injectivity, range of propagation, quality control and stable at high temperature and salinity. Develop cost-effective products

(3) Determine factors (especially geologic) affecting injectivity and propagation of polymer

(4) Development of environmentally acceptable biocides for use in polymer flooding

PROFILE MODIFICATION

Areas of Needed Research

Near-term

(1) Accumulation of more extended data on the influence of reservoir parameters on properties of gels (especially gelation kinetics)

(2) Improved models for prediction/design of profile modification process

Mid-term

(1) Improved accuracy in treating the target zone without damage to productive zones

(2) Development of methods for achieving the desired effect over an extended region

Long-term

(1) Delineation of rheological properties of gels and pregels

(2) Develop a better understanding of the differences between behavior in bulk and in pores

(3) Improved crosslinking systems which are nontoxic and environmentally benign

(4) Improved gel systems which are stable at high temperature and salinity

THERMAL EOR

Areas of Needed Research

Near-term

(1) Improvement in injection profile control techniques

(2) Better define the known mobility-control techniques to improve areal and vertical conformance

Steam foam process

Some issues that need to be addressed include:

(a) What is the best way to introduce surfactant with steam slug; semi-continuous; continuous?

(b) Under what condition do these injection modes work best?

(c) Optimum surfactant concentration?

(d) Effect of rock/fluid properties on steam-foam process?

(e) Influence of salt on the process?

(3) Improvement in steam quality measurement and control

(4) Development of reliable methods for determining phase splitting at the steam distribution system branches and techniques to ensure a relatively even flow splitting between branches

(5) Development of better techniques of heat management and steam generation

(6) Improved subsurface equipment and completion techniques

(7) Development of methods to treat and/or use brackish water for steam generation

(8) Improvement in horizontal wells completion technique for the high-temperature and sanding environment

(9) Development of methods to deplete bypass zones

(10) Development of cost-effective methods to utilize or dispose produced water

(11) Improvement of water-alternating steam Process (WASP).

Some problems include:

(a) What are the optimum slug sizes (water, steam)?

(b) How effective is the process in improving sweep and recovery efficiency?

(c) To what extent will the process minimize steam breakthrough severity?

Mid- and long-term research needs

(1) Development of improved method of reservoir characterization

(2) Development of techniques to steamflood consolidated sands

(3) Research on the best method to steamflood light oil reservoirs to maximize recovery

(4) Improved techniques to steamflood fractures and/or dolomite reservoirs

(5) Development of improved reservoir description tools such as high temperature logging tools, cross hole tomography, etc.

(7) Research on high temperature two- and three- phase relative permeability measurement involving oil, water and steam

(6) Development of techniques to steamflood reservoirs with bottom water drive and on gas caps

(8) Development of thermal EOR techniques for recovery of heavy oil from environmentally sensitive areas

(9) Investigation of the role of high temperature on wettability changes, imbibition effects and critical gas saturations on recovery from consolidated formations

(10) Determination of the effect of high temperature and high pH steam/liquid on rock-fluid chemistry

(11) Development of improved simulation techniques

RESERVOIR CHARACTERIZATION

Areas of Needed Research

Near-term

(1) Development of computer-based database management systems that allow data from all disciplines, at all scales, including non-numeric information to be easily integrated and output to a wide range of end-user applications

(2) Development of methodology for systematic reservoir characterization that includes systematic data collection, analyses, integration and utilization of all types of data (including semi-quantitative) from various sources and that addresses the types and amount of data required for various recovery processes

(3) Innovative methods to extract reservoir properties from engineering data, especially data from older reservoirs

(4) Predictive models of the spatial distribution of reservoir characteristics in the interwell area. The development of these models requires large amounts of quantitative geologic and petrophysical information from reservoir analogs

(5) Development of a reservoir classification system and the determination of the degree to which properties can be transported from one reservoir to another

(6) Measurement of accurate relative permeability and development of correlations

(7) Determination of rock-mechanical properties, from P and S wave studies to determine variations in rock-mechanical properties like compressibility, Poisson's ratio, etc. Integration of seismic results with laboratory measured values from core sample.

Mid-term

(1) Development of diagenetic models that predict the spatial distribution of diagenetic phases within specific reservoir strata on the interwell to field scale

(2) Documentation and model development of the spatial distribution of geochemical characteristics within a reservoir

(3) Increased penetration distance and vertical resolution of petrophysical characteristics measured by well logging tools

(4) Integration of seismic date (megascale) with interwell measurements (macroscale) and core measurements macro- to micro-scale

(5) Scaling-up procedures of various reservoir properties including relative permeability, for determining simulator grid block values

Long-term

(1) Determination of reservoir permeability from geophysical techniques including acoustic logging and crosshole tomography

(2) Integration of theoretical seismic model studies with field data

(3) Application of well testing to more heterogeneous reservoirs

(4) Improved geophysical techniques for reservoir definition at a reasonable cost

RESEARCH NEEDS TO MAXIMIZE ECONOMIC PRODUCIBILITY OF THE DOMESTIC OIL RESOURCE

PART II
EOR FIELD CASE HISTORIES

by Dwight L. Dauben

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RESEARCH NEEDS TO MAXIMIZE ECONOMIC PRODUCIBILITY OF THE DOMESTIC OIL RESOURCE

PART II
EOR FIELD CASE HISTORIES

INTRODUCTION

Part II of this study is designed to identify the technical constraints which have developed as a result of field testing. This perspective is critical since the ultimate test of viability is to successfully demonstrate that oil can be recovered in a cost effective manner in the field. Also, problems may develop in a field application which are not obvious from laboratory testing. Technical constraints, identified with the input of field tests, will have the best prospects of being on target and having practical significance.

Summary and Conclusions

A study of 84 field projects was conducted to determine the constraints which limit the recovery from enhanced oil recovery (EOR) projects. The reviews were based upon the open literature, Department of Energy (DOE) publications, previous K&A evaluations of the DOE cost shared projects, and corporate experience. The reviews were made on a project-by-project basis, and the results are summarized in appendices A-D. The reviews determined the key technical constraints which limited the effectiveness of the project. This field-derived information provides important input in the total assessment of the constraints which currently limit EOR potential.

Two broad categories of constraints appear to affect all of the EOR processes in the field:

(a) Reservoir Heterogeneity, Mobility Control. Around 30% of the total identified constraints fit into this category. Reservoir heterogeneities have a major impact on the sweep efficiency of injected fluids. Because of the high cost of injectants in EOR projects, it is critical that a good understanding of the reservoir exists and that sweep efficiency is maximized. Mobility control is a closely associated parameter since it, along with reservoir heterogeneities, controls the level of sweep efficiency achieved. The common occurrence of these two closely associated parameters suggests an important area for additional research.

(b) Downhole Completions, Operations. This category affects all of the EOR processes, but has particular significance in in situ combustion technology. Problems in these categories primarily affect costs, which ultimately affect oil recovery. Although additional research is needed to develop improved equipment and procedures, the major efforts should be to more effectively use existing technology.

The major technical constraints have been identified for each of the processes based upon field results. It is emphasized that the constraints derived from this source are not all inclusive. Some of the problems which are known to exist may not be evident from field tests. The following are the major technical constraints for each process based upon field data.

Polymer Flooding

These technical constraints were derived from evaluation of polymer floods, crosslinked or gelled polymer systems, and micellar-polymer flooding.

(a) Polymer Propagation. One of the most prevalent characteristics in chemical projects has been the failure of polymers to propagate through the reservoir. Plugging has been a common occurrence, and polymer has been frequently injected above the pressure parting level to achieve a minimum level of injectivity. Propagation is less critical in polymer floods and in crosslinked or gel applications since incremental oil recovery can be achieved with partial penetration.

(b) Degradation. The commonly used polyacrylamides and the xanthan biopolymers are subject to degradation from several mechanisms. Field tests show that polyacrylamides are degraded chemically by the presence of trace amounts of oxygen and multivalent cations such as iron. The xanthan biopolymer has been degraded in various field tests by microbial attack.

(c) High Temperature, High Salinity Environment. The current polymers become unstable or ineffective in reducing fluid mobility under conditions of higher temperature and higher salinities. Suitable polymers are needed to increase the number of reservoirs which are suitable for polymer flooding and micellar-polymer flooding.

Profile Modification

The technical constraints for polymers are also applicable for profile modification. In addition, attention is needed on establishing better design criteria. These include: (1) better definition of reservoir characteristics which are suitable for profile modification, (2) consideration of improved placement techniques, and (3) improved definition of critical design parameters (penetration requirements, degree of permeability reduction required). Additional concerns are the long term stability of polymers and gels, and the propagation characteristics of sequentially injected polymer and crosslinking agents.

Micellar-Polymer Flooding

(a) Excessive Chemical Loss. The surfactants which are an integral part of the micellar-polymer process are lost or rendered ineffective in the reservoir by a number of mechanisms. Field tests have shown that preflushes to precondition the reservoir to the proper ionic environment have not been effective. Exxon has been successful in the field with surfactants designed to displace oil within the ionic environment as it exists at the start of the project. Research is needed to develop and to evaluate surfactant systems which can be tailored to work within the existing ionic environments of a specific reservoir.

(b) Process Design, Operations. Field tests show that these categories of constraints greatly impact costs. Through careful design of the project and close monitoring, many of the problems in these categories can be eliminated.

(c) Inherent Design Weaknesses. The micellar-polymer process has some inherent weaknesses. One of the major problems arises from the need for two dissimilar fluids to travel in sequence and to remain intact through long interwell distances. The velocity-dependent displacement characteristics of the process results in higher recoveries in the more permeable zones and in areas close to the injection wellbore. Recovery is lower in the lower permeability sections and in the interwell regions where frontal velocities are reduced. These mechanisms, coupled with the propagation problems for the polymers, tend to make the process applicable only for close spacing. Innovations in technology are needed.

Alkaline Flooding

Alkaline floods have performed poorly in the past. Major constraints are:

(a) Excessive Consumption. The basic problem is that the injected alkaline fluids are highly reactive with the divalent ions in the formation water, divalent ions associated with clays, and with mineral constituents such as gypsum. Preflushing to create a controlled ionic environment within the reservoir has not been effective. Laboratory studies incorporating an alkaline fluid, an added cosurfactant, and polymer have shown promise. Additional research is needed.

(b) Operational Problems. Major operational problems in the field have been the occurrence of scale in offsetting producers. These can be largely controlled by scale inhibition programs and periodic acid treatments.

Gas Injection

Gas injection projects considered in this study include CO_2 miscible displacement, CO_2 immiscible displacement, gravity stable displacement, and nitrogen injection.

(a) Reservoir Heterogeneity. Field tests show that reservoir heterogeneities have had a major impact in the poor sweep efficiencies that have been realized in many projects.

(b) Mobility Control. The high mobility of injected gas is an additional factor in the poor sweep efficiencies observed in field projects. Efforts to improve the sweep through processes such as water and gas (WAG) have had mixed results. The WAG process has the potential for increasing the sweep, but possibly at a price of reduced oil displacement efficiency. Considerable research efforts are underway to evaluate other processes such as foams, polymers, and gels for improving sweep. The combined areas of reservoir characterization and mobility control are fruitful areas for research. However, it is cautioned that such efforts need to address the detrimental effects on injectivity which may occur.

(c) Injectivity. Field tests show injectivity is often lower than would be predicted from laboratory or simulation studies. An awareness of these characteristics is needed in the design of new projects and in the development of better methods for improving sweep.

(d) Operations. Field tests show the major operational problems to be corrosion control for CO_2 projects and artificial lift problems which occur with the breakthrough and production of significant quantities of gas. These operations problems are significant but are largely resolved by careful planning and monitoring of performance.

Steam Injection

Emphasis in this evaluation was the steamdrive process. Steam injection-production on a single well was considered an important part of the total process.

(a) Gravity Segregation. Gravity segregation appears to be the dominate problem in steam injection projects. In spite of considerable efforts using mechanical procedures and chemical diversion techniques, the gravity segregation problems persist.

(b) Reservoir Heterogeneity. The effects of reservoir heterogeneities upon performance are similar to those of other processes. The high mobility of steam tends to accentuate an existing reservoir heterogeneity problem.

(c) Downhole Completions. Field tests show a considerable number of operational problems such as sand control and the failure of thermal packers. Although these problems impact cost, they are largely resolved by prudent design and operation of the project.

(d) Steam Generation. The cost for generating steam in a new project is a major factor. The primary factors controlling cost are the price and availability of fuel, pollution control costs, and water treating costs. The environment in California has been ideal as a resource of heavy oils and as a location for the generation of steam. The ability to produce steam at reasonable costs will become increasingly important as applications in other parts of the United States develop. Additional research studies are warranted to support the extension of commercial steamflood projects into other geographic areas. Alternative boiler designs are suggested.

In Situ Combustion

In situ combustion technology has high potential for increasing recovery of heavy oils, including those which may not be suitable candidates for steam injection. However, field results have been discouraging, and there have been few economic successes. The following are the major technical constraints.

(a) Reservoir Heterogeneity. Field results show that reservoir heterogeneities impact in situ combustion projects more than any other process. Sweep efficiency is often very low because of the large volumes of non-combustible gases which finger prematurely to the producing wells. The channels created by these vent gases provide a path of least resistance for the combustion front. The use of oxygen, rather than air, reduces the channeling problem since all of the injected gas is consumed during the combustion process. However, the use of oxygen increases the concerns about corrosion and increases the possibility of an explosion.

(b) Downhole Completions. The major problems in this category are erosion and corrosion related to sand production in the producers, burnback of the combustion front in the injection wells, and combustion front breakthrough in producing wells. Field experience indicates these problems to be severe but resolvable. The major impact becomes cost control.

(c) Operations. Corrosion and oil treating are the major problems in this category. These problems are resolvable, but have a major impact on cost control. The high operational costs make many of the in situ combustion projects unprofitable.

Microbial Enhanced Oil Recovery

MEOR has the potential for increasing oil recovery by a number of mechanisms, including improved waterflood displacement, improved sweep, and producing well stimulation. Although the concept of MEOR has been in existence for a long time, there is a general absence of definitive field tests. Thus, the best gauge of current technical constraints is developed largely from laboratory studies, as discussed in chapter 5, Part I. The on-going and planned field tests being conducted by NIPER and by the University of Oklahoma will hopefully provide additional information on process capabilities and limitations.

Limitations

An assessment was made for each reviewed project on two broad categories of limitations for each identified constraint. Technical limitations are those which are attributed to shortcomings in the technology. Management limitations are those where the project was conducted using technology which was less than the state-of-the-art at the time. The decision to classify a constraint within either category was sometimes difficult and subjective. Although the selection of a category can be questioned for a particular project, the overall conclusions from this assessment are considered valid. These results show:

(a) Project management limitations represented about one-third of the total identified constraints.

(b) Project management limitations were greater in the more complex EOR processes and lesser in the simpler processes.

(c) Project management limitations were greater in design, injection-related constraints, and in operations.

(d) Technology limitations were greater for reservoir-related constraints, such as reservoir heterogeneity, reservoir description, reservoir conditions, chemical consumption, gravity segregation, and mobility control.

The above results suggest the need for company management to commit the manpower, technical, and financial resources necessary to design and implement complicated EOR projects.

Also, the above results suggest an urgent need for the transfer of technology to operators who are contemplating an EOR project.

Assessment of Current Research Activity

A study of the technical literature was made to assess if the industry is currently conducting research to address the major technical constraints affecting EOR. This analysis was conducted by reviewing 599 publications and entering the appropriate information into a database. The analysis showed that current research is addressing many of the technical constraints which have been identified through the years by laboratory and field testing. Results are qualified in some of the processes due to technical and/or economic conditions which have resulted in few additional field trials. Such processes include micellar-polymer flooding and in situ combustion. The results of the analysis indicate that the areas of major research deficiency are in the evaluation of reservoir heterogeneity and in the closely related areas of downhole completions and operations. These areas correspond with the major technical constraints which affect all EOR processes.

Approach Used In Case History Study

This portion of the study was conducted by reviewing the published results of various EOR field projects which have been conducted over the years. The study was conducted using a systematic approach so that projects could be compared as much as possible on a common basis. Appendices A-D summarize the results of the various field tests, considering the following major topics:

(a) Project Identification (Name, Location, Operator, etc.)

(b) Process Design Summary

(c) Reservoir Parameters as Compared to NPC Screening Criteria

(d) Technical Constraints and Limitations

A list of references is provided at the end of each section which served as the basis for the interpretations given in the summaries.

The technical constraints identified for each project help to explain why the project did not perform as well as might have been expected. These could be related to the process, the reservoir, or to various operating problems. The technical constraints were further placed in certain categories to better identify the major problem areas. Table II-1 shows the classification of constraints. As might be expected, technical constraints do not always fit uniquely into a category.

For example, the injection of a high mobility fluid (e.g., steam) can lead to poor sweep because of gravity segregation, reservoir heterogeneities, or a poor mobility ratio.

Two broad categories of limitations are listed to further characterize the project.

Technical limitations are those which are attributed to shortcomings in the technology of the process or industry's ability to apply the technology in the reservoir when using state-of-the-art technology.

Management limitations are those where the project was conducted using technology which was less than the state-of-the-art at the time it was conducted. Management limitations could involve one or more of the following:

(a) Current technology was not used in the project. The operator may not have been fully aware of technological developments which have been made on a particular process.

(b) Important information was overlooked or ignored during the screening process.

(c) Operating guidelines were not properly established or enforced.

(d) Timely decisions were not made during project monitoring.

It must be recognized that an assessment of technical versus management limitations is sometimes difficult and subjective. The classification of any one project may be subject to question. However, the conclusions reached from the study as a whole on this point are considered to be accurate and reflective of the industry at the time.

The evaluated projects were selected to be representative of the various EOR processes, the various reservoir conditions, and the different geographic regions. Limitations on the scope of this project prevented a complete review of all known projects. Advantage was taken of the detailed reviews performed by K&A Energy Consultants, Inc. on the various EOR projects conducted under the DOE's cost shared program.

EOR Constraints In Field Projects

The projects were reviewed with a goal of identifying the technical constraints which limit the application of EOR methods in the United States. The input received from these field tests will help to identify the technical constraints which have the greatest practical implications in implementing the technology. Research programs which address these technical constraints are assured of being significant. Table II-2 identifies the various projects which were reviewed in this study. Table II-3 shows the distribution of EOR constraints by process for all of the field tests. Tables II-5 through II-10 provide additional detail by process for the specific problems and/or constraints which affected individual projects.

An important consideration is that the constraints, as identified by field tests, do not provide the total input needed to develop a targeted research program. Field tests may identify key problem areas, but may not identify the exact mechanisms involved. For example, the failure to propagate polymer through the reservoir may be due to shear degradation, chemical degradation, adsorption, or reservoir-related problems. Other supporting information would be needed to identify more precisely the problem areas.

TABLE II-1
CLASSIFICATION OF EOR CONSTRAINTS

CLASSIFICATION	EXPLANATION
Chemical Loss	Loss of injected fluid due to chemical, mechanical, or microbial degradation; chemical loss due to adsorption, ion exchange, or entrapment.
Downhole Completion	Completion techniques; equipment; production problems unrelated to corrosion, scale, or artificial lift.
Facility Design	Surface injection or production facilities.
Fluid Containment	Refers to fluid ingress/egress from project area as distinguished from out-of-zone injection in injection control.
Gravity Segregation	Gravity override in steam; potential may exist for override in situ or gas injection projects.
Injectivity	Process specific to gas injection projects. Low polymer injectivity in chemical projects was considered inherent to the polymer process.
Injection Control	Formation pressure parting; injected fluid flow out of intended zone; inadequate monitoring of injection.
Injectant Quality	Steam quality at sandface; injection well plugging related to poor mixing (polymer) or injection system contaminants (rust, lubricants).

TABLE II-1 continued
CLASSIFICATION OF EOR CONSTRAINTS

CLASSIFICATION	EXPLANATION
Mobility Control	Gas channeling related to mobility rather than heterogeneity; breakdown of polymer bank due to bacterial degradation.
Operations	Problems with oil treating, corrosion, scale, artificial lift, compression, formation plugging unrelated to injectant quality.
Process Design	Inadequate or incomplete investigation of areas known to be important in the different EOR processes.
Reservoir Conditions	Refers to reservoir fluid conditions such as oil saturation, thickness of oil column, reservoir drive mechanism, etc. As defined, reservoir conditions are a subset of reservoir description.
Reservoir Description	Refers to rock related description such as depositional environment, rock composition, faulting, heterogeneity, continuity, etc.
Reservoir Heterogeneity	Areal or vertical permeability variations, faults, directional flow trends, depositional environments, etc.

TABLE II-2
EOR FIELD PROJECTS REVIEWED
CHEMICAL PROJECTS

NUMBER	PROJECT NAME	OPERATOR	PROCESS DESCRIPTION	DATE STARTED	SIZE
1	Bell Creek	Gary-Williams	Micellar-Polymer	1981	Field
2	Big Muddy	Conoco	Micellar-Polymer	1980	Field
3	El Dorado	Cities Service	Micellar-Polymer	1975	Pilot
4	Loudon	Exxon	Micellar-Polymer	1980	Pilot
5	Loudon 2nd Ripley	Exxon	Micellar-Polymer	1982	Pilot
6	Manvel Field	Texaco	Micellar-Polymer	1977	Pilot
7	North Burbank Unit	Phillips	Micellar-Polymer	1975	Pilot
8	Robinson M-1	Marathon	Micellar-Polymer	1977	Field
9	Salem Unit	Texaco	Micellar-Polymer	1981	Pilot
10	Sloss Field	Amoco	Micellar-Polymer	1977	Pilot
11	West Burkburnett	Mobil	Micellar-Polymer	1973	Field
12	Coalinga	Shell	Polymer Flooding	1978	Pilot
13	Hitts Lake	Sun	Polymer Flooding	1980	Field
14	North Burbank	Phillips	Polymer Flooding	1980	Field
15	North Stanley	Gulf	Polymer Flooding	1976	Field
16	Oerrel Field	Texaco	Polymer Flooding	1975	Pilot
17	Sleepy Hollow	Amoco	Polymer Flooding	1985	Field
18	Storms Pool	Energy Resources	Polymer Flooding	1980	Pilot
19	Big Horn Basin	Marathon	Crosslinked Polymer	1985	Pilot
20	Nelson Unit	Arco	Crosslinked Polymer	1984	Pilot
21	Sho-Vel-Tum	Mobil	Crosslinked Polymer	1981	Field
22	Isenhour Unit	Belco Petroleum	Alkaline-Polymer	1980	Field
23	Wilmington	THUMS	Alkaline	1979	Pilot

TABLE II-2, CONT'D
EOR FIELD PROJECTS REVIEWED
GAS INJECTION PROJECTS

NUMBER	PROJECT NAME	OPERATOR	PROCESS DESCRIPTION	DATE STARTED	SIZE
1	Dollarhide	Unocal	CO_2 Miscible Displacement	1985	Field
2	Ford Geraldine	Conoco	CO_2 Miscible Displacement	1981	Field
3	Garber Field	Arco	CO_2 Miscible Displacement	1981	Field
4	Little Knife	Gulf	CO_2 Miscible Displacement	1980	Pilot
5	Maljamar Field	Conoco	CO_2 Miscible Displacement	1983	Pilot
6	Means S. Andres	Exxon	CO_2 Miscible Displacement	1983	Field
7	NE Purdy Unit	Cities Service	CO_2 Miscible Displacement	1982	Field
8	SACROC Unit	Chevron	CO_2 Miscible Displacement	1972	Field
9	Slaughter Estate	Amoco	CO_2 Miscible Displacement	1976	Pilot
10	Two Freds Field	HNG Fossil	CO_2 Miscible Displacement	1974	Field
11	West Sussex	Conoco	CO_2 Miscible Displacement	1982	Pilot
12	Lick Creek	Phillips	CO_2 Immiscible Displacement	1976	Field
13	Wilmington V	Longbeach ODC	CO_2 Immiscible Displacement	1982	Field
14	Wilmington	Champlin	CO_2 Immiscible Displacement	1981	Pilot
15	Camurlu Field	Turkey	CO_2 Cyclic Stimulation	1984	Pilot
16	Bay St. Elaine	Texaco	Gravity Stable, CO_2 Miscible	1981	Field
17	Timbalier Bay	Chevron	Gravity Stable, CO_2 Miscible	1984	Pilot
18	Weeks Island	Shell	Gravity Stable, CO_2 Immiscible	1978	Pilot
19	Intisar D	Occidental	Gravity Stable, Hydrocarbon Miscible	1969	Field
20	Hawkins Field	Exxon	Gravity Stable, Flue Gas Immiscible	1977	Field
21	Lake Barre	Texaco	Gravity Stable, N_2 Immiscible	1978	Field
22	Anschutz Ranch	Amoco	Nitrogen Miscible	1982	Field
23	Jay-LEC Fields	Exxon	Nitrogen Miscible	1981	Field

TABLE II-2, CONT'D
EOR FIELD PROJECTS REVIEWED
IN SITU COMBUSTION PROJECTS

NUMBER	PROJECT NAME	OPERATOR	PROCESS DESCRIPTION	DATE STARTED	SIZE
1	Brea-Olinda	Union Oil	Air, Dry Combustion	1972	Field
2	Fry Unit	Marathon	Air, Dry Combustion	1961	Field
3	Glen Hummel	Sun	Air, Dry Combustion	1968	Field
4	Gloriana Field	Sun	Air, Dry Combustion	1969	Field
5	West Heidelberg	Gulf	Air, Dry Combustion	1971	Field
6	South Hospah Field	Tenneco	Air, Dry Combustion	1980	Pilot
7	Midway Sunset	Mobil	Air, Dry Combustion	1968	Field
8	Miga Field	Gulf	Air, Dry Combustion	1964	Field
9	Posesti	Romania	Air, Dry Combustion	1971	Field
10	Suplacu de Barcau	Romania	Air, Dry Combustion	1964	Field
11	Talco Field	Exxon	Air, Dry Combustion	1972	Pilot
12	Trix-Liz Field	Sun	Air, Dry Combustion	1968	Field
13	North Ward Estes	Gulf	Air, Dry Combustion	1978	Pilot
14	Bellevue Field	Getty	Air, Wet Combustion	1963	Field
15	Bodcau (Bellevue)	Cities Service	Air, Wet Combustion	1976	Field
16	Golden Lake	Husky Oil	Air, Wet Combustion	1969	Pilot
17	Schoonebeek	Shell	Air, Wet Combustion	1960	Pilot
18	Sloss Field	Amoco	Air, Wet Combustion	1967	Field
19	East Tia Juana	Shell	Air, Wet Combustion	1966	Pilot
20	Forest Hill	Greenwich	Oxygen, Dry Combustion	1976	Pilot
21	Marguerite Lake	BP Resources Canada	Oxygen, Wet Combustion	1978	Pilot

TABLE II-2, CONT'D
EOR FIELD PROJECTS REVIEWED
STEAM INJECTION PROJECTS

NUMBER	PROJECT NAME	OPERATOR	PROCESS DESCRIPTION	DATE STARTED	SIZE
1	200 Sand	Santa Fe	Steamdrive	1975	Field
2	Brea Field	Shell	Steamdrive	1963	Field
3	Cat Canyon	Getty	Steamdrive	1977	Pilot
4	El Dorado	Cities Service	Steamdrive	1965	Pilot
5	Georgsdorf	BEB GMBH	Steamdrive	1975	Field
6	Kern River	Getty	Steamdrive	1970	Field
7	Nacatoch Sand	Phillips	Steamdrive	1964	Field
8	N. Midway McKittrick	Getty	Steamdrive	1964	Field
9	Ruehlertwist	Wintershall	Steamdrive	1978	Pilot
10	Saner Ranch	Conoco	Steamdrive	1981	Pilot
11	Shiells Canyon	Texaco	Steamdrive	1973	Pilot
12	Schoonebeek	Shell	Steamdrive	1960	Pilot
13	Ten-Pattern	Chevron	Steamdrive	1968	Pilot
14	Tia Juana	Shell	Steamdrive	1961	Field
15	Winkleman Dome	Amoco	Steamdrive	1964	Field
16	Yorba Linda	Shell	Steamdrive	1971	Pilot
17	Tia Juana	Shell	Steam Stimulation	1964	Field

Technical Constraints Affecting All Processes

As shown in table II-3, two broad categories of constraints appear to exist in all of the EOR processes. These are:

(a) Reservoir Heterogeneity, Mobility Control. Although these two constraints are separately identified, they are normally interrelated. As shown in table II-3, around 30% of the total identified constraints were in the combined categories of reservoir heterogeneity and mobility control. Reservoir heterogeneities can cause injected fluids to advance nonuniformly through the reservoir. The result can be lower oil recovery and poorer economics. The invasion pattern is accentuated by the mobility ratio. For example, the injection of a high mobility fluid such as a gas tends to worsen a problem which may already exist. These two constraints exist in all of the processes, but appear to be particularly severe in in situ combustion projects. The common occurrence of these constraints suggests a good area for research. However, it should be recognized that there are facets to the problem which must be carefully considered. Some of these pertinent issues are:

(1) Small-scale heterogeneities may dominate flow behavior in a small pattern but have no significant effect in a larger scale pattern. Thus, an observed problem in a small pattern area may not actually be a problem when expanded into a larger operation.

(2) High-capacity flow channels can be the major source of a sweep problem. However, such channels can provide a source of early flush oil production which contributes to the economic viability of the project (Pollock, 1969). The initial channeling of steam through such a high capacity zone can also provide a means for transferring heat into the formation quickly and permit a larger initial oil recovery response. In such case, oil recovery may be reduced later due to the excess cycling of steam. The point is that the adverse effects of heterogeneities must be balanced against some of the benefits which may exist.

(3) Use of mobility control techniques and/or selective plugging may lead to improved sweep efficiency by reducing the adverse effects of reservoir heterogeneities. However, these benefits must be assessed with the resulting injectivity reductions which will occur. This consideration must be addressed particularly in carbonate

TABLE II-3
DISTRIBUTION OF EOR CONSTRAINTS BY PROCESS

TYPE OF CONSTRAINT	CHEMICAL	GAS	IN SITU	STEAM	TOTAL
Mobility Control	5	6	1	--	12
Reservoir Heterogeneity	6	6	11	7	30
Downhole Completions	1	--	6	6	13
Operations	6	9	6	--	20
Fluid Containment	2	--	1	--	3
Injection Control	6	4	3	--	13
Injectant Quality	2	1	1	3	7
Facility Design	4	--	2	3	9
Process Design	7	1	1	--	9
Reservoir Conditions	1	--	5	2	8
Reservoir Description	1	--	5	--	6
Injectivity	--	6	--	--	6
Chemical Consumption	5	--	--	--	4
Gravity Segregation	--	--	1	6	7
TOTAL	46	33	43	27	147

rocks where the permeabilities are inherently low and injectivity can be a severe problem.

(b) Downhole Completions, Operations. A second key area which impacts all EOR processes is the general category of downhole completions and operations. As shown in table II-3, in situ combustion projects are impacted particularly by completion and operation practices. Typical operations problems include oil treating, corrosion, scale, and compression. The impact of these problems is principally on costs. With increased operating costs, profitability of the project is decreased, and the project may need to be terminated early. The technology is largely available to address these problems. The key is the proper application of existing technology and the development of lower cost methods to address operational needs.

Limitations

An assessment was made in each of the project summary sheets in the appendices on two broad categories of limitations for each identified constraints. These were technical or management limitations. As previously discussed, technical limitations are those which are attributed to shortcomings in the technology of the process or industry's ability to apply the technology in the reservoir when using state-of-the-art. Management limitations are those where the project was conducted using technology which was less than the state-of-the-art at the time it was conducted.

Table II-4 summarizes the assigned type of limitation by process type and by the type of constraint. The following conclusions are reached by this analysis:

(a) Project management represented about one-third of the total identified limitations. This overall conclusion is considered valid even though there may be questions on the designation of limitations on individual constraints. Information was not generally available on the reasons why the state-of-art technology may not have been used in a particular project.

(b) Project management limitations were higher in the more complex EOR processes and lower in the less complex processes. For example, project management limits the more complex chemical processes by around 45% of the total compared to around 25% for the more straightforward gas injection or steamflood projects.

TABLE II-4
EOR FIELD PROJECT LIMITATIONS

BY TYPE OF PROCESS

TYPE OF PROCESS	TECHNOLOGY		MANAGEMENT		TOTAL NUMBER
	NUMBER	PERCENT	NUMBER	PERCENT	
Chemical	32	56	25	44	57
Gas	28	82	6	18	34
In situ	34	63	20	37	54
Steam	23	77	7	23	30
TOTAL	117	67	58	33	175

BY TYPE OF CONSTRAINT

PRIMARY LIMITATION	TYPE OF CONSTRAINT	TECHNOLOGY		MANAGEMENT		TOTAL NUMBER
		NO.	PERCENT	NO.	PERCENT	
Management	Facility Design	4	40	6	60	10
	Process Design	5	36	9	64	14
		9	38	15	62	24
	Fluid Containment	3	50	3	50	6
	Injection Control	5	36	9	64	14
	Injectant Quality	1	13	7	87	8
		9	32	19	68	28
	Downhole Completion	12	86	2	14	14
	Lift, Corrosion, Emulsion	18	75	6	25	24
		30	79	8	21	38
	Subtotal Management	48	53	42	47	90
Technology	Reservoir Conditions	6	60	4	40	10
	Reservoir Description	4	40	6	60	10
		10	50	10	50	20
	Injectivity	6	100	0	0	6
	Chemical Consumption	5	100	0	0	5
	Gravity Segregation	7	100	0	0	7
	Mobility Control	11	85	2	15	13
	Reservoir Heterogeneity	30	88	4	12	34
		59	91	6	9	65
	Subtotal Technology	69	81	16	19	85
TOTAL MANAGEMENT AND TECHNOLOGY LIMITATIONS		117	67	58	33	175

(c) Project management limitations were higher in design, injection-related constraints, and in operations. These conditions are generally those where the operator has the technology available and can control the outcome of the results.

(d) Technology constraints were higher for reservoir-related constraints, such as reservoir heterogeneity, reservoir description, reservoir conditions, chemical consumption, gravity segregation, and mobility control.

The above results suggest that future EOR projects have a higher probability of success by a commitment on the part of company management to use the manpower, technical, and financial resources to adequately design, implement, and to monitor the project. It is important that the aspects of the project which can be controlled by the operator be implemented in the best possible fashion. There will always be other aspects of the project outside of the control of the operator which pose a challenge. Technology transfer is an equally important concern in getting state-of-the-art information to the operator. This transfer of technology is especially vital to the smaller organizations which do not have large technical staffs or in-house research facilities.

The above results also suggest that the fruitful areas of research are those which relate to a better understanding of the reservoir and to previously discussed technical constraints which are unique for each process.

Technical Constraints Affecting Polymer Flooding

The technical constraints for polymer flooding are identified based upon the field experience for polymer injection projects, crosslinked or gelled polymer projects, and micellar-polymer projects. Tables II-5 and II-6 provide details on the problem areas for polymers. The following are the major problem areas based upon field results:

(a) Polymer Propagation. One of the most prevalent characteristics in chemical projects is the failure of polymers to propagate through interwell distances to the producing wells. Poor propagation may be evident by analyzing samples from offset producers, pressure transient testing, or by an excessive amount of injectivity reduction. This poor propagation occurs even though the polymer may be mechanically and chemically stable when injected. Poor propagation is most obvious in micellar-polymer projects, where it is critical to propagate polymer through interwell distances. Propagation is less critical

TABLE II-5
CONSTRAINTS FOR POLYMER FLOODING

CONSTRAINTS	FIELD
Reservoir Conditions	Coalinga (error in evaluating movable oil S_o)
Injectant Quality	Coalinga (unhydrated polymer)
Process Design	Coalinga (low injectivity noted in prepilot test) Storms Pool (misapplication of polymers)
Reservoir Heterogeneity	North Stanley (extreme permeability variations) Sleepy Hollow (extreme permeability variations)
Injection Control	North Stanley (injecting above parting pressure)
Facility Design	Oerrel (low injectivity; mixing procedures modified)
Operations	Sleepy Hollow (fines/heavy oil plugged producers) Sleepy Hollow (corrosion-related rod failures)
Chemical Loss	Storms Pool (bacterial degradation of biopolymer)
Downhole Completion	Nelson Unit (portion of injection interval inadequately perforated)

in polymer flooding and in crosslinked polymer projects where it is possible to recover incremental oil production with partial penetration through the reservoir.

An inherent, underlying problem is the nature of the polymers used for mobility control and sweep improvement. To achieve cost-effective mobility control, the currently used commercial polymers have an extremely high molecular weight and are used in low concentrations. Good filtration is required to avoid face plugging. Even with careful filtration, polymers will tend to be mechanically trapped in the smaller pores. Polymers also adsorb on rock and clay surfaces.

Injectivity problems were observed in several projects. Low injectivity was observed in Coalinga, due in part to the low matrix permeability and unhydrated biopolymer (Duane, 1983). Surfactant was successfully injected in several projects, but plugging and/or low injectivity was experienced when the drive polymer was injected. Parting pressures were exceeded in several of these projects during polymer injection, including Big Muddy (Cole, 1988), North Burbank (Tracy, 1982), Manvel (Hamaker, 1982; Widmyer, 1981), Robinson M-1 (Dauben, 1987), and West Burkburnett (Talash, 1981). Under these conditions, the injected polymer would bypass the surfactant bank which had been injected below the parting pressure level. The whole process would thus break down. The decision to increase pressure above the parting level is usually made after poor injectivity is experienced and there is little alternative.

High retention of a biopolymer was observed in the Loudon Second Ripley Surfactant Flood Test (Reppert, 1990). This high retention was observed in spite of successful efforts to stabilize the biopolymer against microbial degradation.

Experience has shown that it is very important to conduct all needed workovers prior to project initiation to help avoid excessive polymer plugging. Workovers conducted after project initiation are likely to result in the polymer entering different zones than previously injected fluids. The preproject workovers conducted in Robinson M-1 were injected to avoid this problem (Dauben, 1987). In spite of the efforts, some injectivity problems and subsequent pressure parting occurred.

Field experience indicates that the restart of polymer injection after a shutdown has been difficult. Such an example is the Sloss micellar-polymer project (Yanosik, 1978).

(b) Degradation. The currently used partially hydrolyzed polyacrylamides and the xanthan-type biopolymers are subject to different forms of degradation. Both polymers tend to be chemically unstable under conditions of higher temperature and higher levels of salinity and hardness. Polyacrylamides are susceptible to shear degradation when injected through perforations into the matrix. Polyacrylamides are also chemically unstable in the presence of trace quantities of iron and oxygen. The major stability problem with the biopolymers is bacterial degradation. The existence of a degradation problem may not be immediately obvious since quality control tests are normally made to insure that injected samples are intact. Most degradation problems occur in the injection string or in the reservoir.

The bacterial degradation of the xanthan biopolymer has been one of the major problems in previous polymer injection projects. Such problems occurred in Loudon (Bragg, 1982), Manvel (Hamaker, 1982), Salem (Widmyer), and Storms Pool (Norton, 1983). The breakdown of the polymer following micellar slug injection usually results in very poor recovery. Past experience has shown that the carbohydrate groups which comprise the xanthan chain are very susceptible to microbial attack. The traditional approach has been to protect the biopolymer through the use of bactericides. Elaborate precautions are needed to treat all surface equipment, tubulars and the near-well area in the reservoir with bactericides to protect the biopolymer from degradation. Even with these precautions, polymer stability is not assured. Field experience from Storms Pool has demonstrated the increased stability problems which can occur when using surface waters which have high bacterial counts (Norton, 1983). Experience has also shown that it is very important, as an end-step in the manufacturing process, to totally kill the fermentation process which produced the biopolymer. Considerable research has been conducted to resolve the stability problem with the xanthan biopolymer. New polymers such as the scleroglucan are being evaluated.

Chemical degradation of a polyacrylamide occurred in the Sloss project (Yanosik, 1978). In the project, the polymer apparently degraded due to its exposure to trace amounts of oxygen and iron picked up from uncoated tubulars. This type of chemical degradation can be controlled by the total exclusion of oxygen and by coating all exposed metal surfaces with a plastic or epoxy material.

Shear degradation of polyacrylamides is suspected to be a common problem. Such a problem is not immediately obvious since the degradation occurs as the polymer flows through perforations into the matrix. This problem can be controlled by increasing the perforation density and/or by adjusting injection rates. No specific field tests are cited.

(c) High Temperature, High Salinity Environment. The currently available polymers tend to lose effectiveness or become unstable under conditions of high salinities and high temperatures. The NPC study (1984) indicates the currently available polymers are applicable in waters with salinities under 100,000 ppm and at temperatures below 200° F. The actual limits are considered to be below these levels in many situations, depending upon the hardness level of the water. These conditions limit the application of polymers in many otherwise suitable reservoirs. Previous studies indicate that the scleroglucans are the most temperature stable of the available polymers, but their ability to increase viscosity on a cost effective basis is doubtful (Davidson, 1984).

The 1,440-acre polymer flood project in the North Burbank Field was successful in recovering a significant amount of oil, but economic viability was doubtful due to the need of injecting a large volume of fresh water to reduce the salinity and hardness of the in-place waters (Moffitt, 1990). A fresh water preflood was also required in a polymer flood conducted in the Oerrel field, Germany (Martin, 1981).

Technical Constraints Affecting Profile Modification Treatments

Time-set chemical gels and sequential polymer crosslinking techniques have been used in recent years to improve the recovery of oil through sweep improvement. Most of these treatments have used polymers as an integral part of the process. Thus, the technical constraints described in the previous section also apply to profile modification. The field treatments described in this study show a high degree of success. However, the overall industry success is probably much lower due to the tendency not to report failures. The following are critical areas in design/research needed to increase the degree of success.

(a) Identification of Suitable Reservoir Conditions. One of the major uncertainties is the identification of reservoir conditions where a profile modification treatment will be successful. Generally, a small volume treatment has the potential for improving sweep where the permeable layer(s) are isolated from the remaining portions of the reservoir by crossflow barriers. The placement of a flow reducing fluid into the permeable layer(s) can thus result in the modification of the injection profile and affect the flow distribution throughout the reservoir. If crossflow barriers do not exist, then the improved injection profile will not lead to improvement in the oil recovery or change in the water-oil-ratio.

Field treatments are often performed in reservoirs where there are uncertainties on the existence and continuity of crossflow barriers.

(b) Placement Techniques. Ideally, the fluids will be injected only into the permeable zone(s) by mechanical isolation or by an inherent characteristic of the fluid. Invasion of the fluid into the tighter sections would tend to worsen an existing flow distribution problem. Practically, selective injection is not normally possible due to the expense of workovers to mechanically isolate the zones or to a lack of understanding on the identity and location of the high-permeability zones. Most of the injected fluids flow in the desired interval because of its higher permeability. Selectivity is further enhanced by the tendency of polymers to flow preferentially through the larger pores (Inaccessible pore volume concept) and by the tendency of gels to form more strongly in the lower oil saturation areas characteristic of the higher permeability zones.

Additional development is needed to further improve the placement of flow reducing fluids into the desired intervals.

(c) Control of Critical Design Parameters. The critical factors affecting effectiveness are the degree to which the permeability is reduced, the distance to which the fluid penetrates the zone(s), and the stability of the polymer or gel. Chemical gels provide the highest flow resistance, but penetration is limited by the set times, usually no more than a few days. Set times are normally reduced at the higher temperatures. The sequential injection of polymer and crosslinking agent has the potential for more in-depth penetration but achieves a lower level of flow reduction. Questions have also been raised on the propagation effectiveness of the sequential process.

Phillips describes an improved sequential crosslinking process using chromium propionate as an alternative to aluminum citrate (Moffitt, 1990). This process is reported to be more effective in higher salinity waters.

Continued research is needed to develop chemical systems which have a wide range of capabilities and which can be tailored to meet the needs of a particular application.

Technical Constraints in Micellar-Polymer Flooding

The technical constraints for the various micellar-polymer field tests are summarized in table II-6. The following are the major technical constraints for micellar-polymer flooding:

TABLE II-6
CONSTRAINTS FOR MICELLAR-POLYMER FLOODING

CONSTRAINTS	FIELD
Injectant Quality	Bell Creek (erratic hardness caused polymer viscosity fluctuations)
Facility Design	Bell Creek (produced oil and water cleanup)
	Sloss (injection well plugging due to use of bare steel and inadequate mixing facilities)
Fluid Containment	Big Muddy (migration of fluid out of reservoir)
Injection Control	Big Muddy (injection above parting pressure)
	Manvel (loss of injected fluid into underlying sand interval)
	North Burbank (micellar slug bypassed by polymer due to injection well stimulations during project)
	West Burkburnett (micellar slug bypassed by polymer due pressure parting)
Process Design	Big Muddy (low injectivity due to excess polymer concentration)
	El Dorado (over-estimation of oil saturation; evidence of extraneous fluid entry prior to project start-up)
	West Burkburnett (failure to anticipate low injectivity)
Operations	Robinson M-1 (oil treatment costs up to $2/bbl)
	Salem (oil treatment costs up to $9/bbl before facilities modification made)
Fluid Containment	El Dorado (extraneous water entry into project area)

TABLE II-6, cont'd

CONSTRAINTS	FIELD
Chemical Loss	El Dorado (high surfactant consumption due to gypsum)
	Loudon, 0.7 ac (bacterial degradation of biopolymer)
	Manvel (degradation of biopolymer, causing early breakthrough of injected fluids)
	North Burbank (high consumption due to adverse salinity and hardness, oil wet rock)
	Robinson M-1 (high consumption due to higher than anticipated salinity and hardness)
	Salem (bacterial degradation of biopolymer)
	Sloss (degradation of biopolymer resulting from stimulation treatments)
	West Burkburnett (high chemical loss due to failure of preflush to remove excessive salinity and hardness)
Reservoir Heterogeneity	Loudon, .7 ac (preferential injection into one zone)
	Robinson M-1 (extreme permeability contrasts, directional flow trends)
	Salem (flow principally in lower zone)
Reservoir Description	Manvel (injection and producing wells not in communication due to previously undetected fault)

(a) Excessive Chemical Loss. The surfactants which are an integral portion of the micellar slug can be lost or rendered ineffective by adsorption on rock and clay surfaces, mixing with in-place saline or high hardness waters, or through cation exchange with consequent phase transfer. The surfactants which have been traditionally used are sensitive to the ionic environment of the reservoir and effectively displace oil only within a relatively narrow range of salinities and hardness. Preflushes have been extensively tested for preconditioning the reservoir and for displacing in-place water in preparation for the surfactant. However, these field tests indicate that the preflushes have not been successful in achieving their objective.

Several field tests are cited. High surfactant consumption occurred in El Dorado due to the calcium released from gypsum in the formation (Ferrell, 1987). The presence of gypsum had not been thoroughly evaluated prior to the project. High surfactant consumption occurred in North Burbank due to the failure of the preflush to remove excessive salinity and hardness and to the oil-wet nature of the rock. Surfactant consumption was high in the Robinson M-1 project due to a higher than expected salinity and hardness (Dauben, 1987). Surfactant consumption was high in the West Burkburnett project due to the failure of the preflush to remove excess salinity and hardness (Talash, 1981).

The Loudon 0.7-acre pilot demonstrated that a surfactant designed to operate in the existing ionic environment of the reservoir was highly effective in displacing oil. This pilot demonstrated the approaches which will likely be required to make micellar-polymer flooding successful (Bragg, 1982; Reppert, 1990).

(b) Polymer Propagation. Perhaps the most critical shortfall in micellar-polymer flooding is the polymer itself. The limitation of polymers is discussed in the previous section. Projects which were greatly impacted by shortcomings of polymers included the Loudon 0.7-acre pilot (Bragg, 1982), Salem (Widmyer, 1985), Sloss (Yanosik, 1978), Bell Creek (Hartshorne, 1984; Fanchi, 1982), and Big Muddy (Cole, 1988). A common problem has been the tendency of polymers to reduce injectivity and the subsequent action of operators increase pressures above the parting level.

(c) Process Design, Operations. These categories of constraints greatly impact project costs. Through careful design of a project and close monitoring, many of the problems in these categories can be eliminated. Examples of constraints in these categories include the bare pipe used in the Sloss project (Yanosik, 1978), the low injectivity in Big Muddy arising from excess polymer concentration (Cole, 1988), the overestimation of oil saturation in the El Dorado project (Ferrell, 1987), and the excess oil treatment costs in the Salem project (Widmyer).

(d) Inherent Design Weaknesses. The micellar-polymer process has some inherent weaknesses which may well limit its application over the long term. The surfactant slug and polymer bank must stay intact and in sequence through the reservoir. The surfactant slug itself will tend to break down as a consequence of its small size due to dispersion. Also, the process breaks down if the two fluids go in different paths. Fluids may tend to travel in separate paths by virtue of differences in their affinity for oil and water. Large differences in molecular weight tend to encourage movement of polymers only through higher permeability zones. For example, surfactants would tend to flow through a lower permeability cross-bed, whereas polymers would tend to bypass the cross-bed or plug at the interface. The velocity-dependent displacement characteristics would tend to reduce oil recovery from tighter zones and in the interwell areas where frontal velocities are reduced. The process thus may not be applicable in the wider spacing.

Innovations are needed to overcome some of the inherent weaknesses of the process. Perhaps horizontal wells or incorporation into a gravity-stabilized process could be used in some manner to improve the process.

Technical Constraints Affecting Alkaline Flooding

Table II-7 identifies some of the technical constraints associated with alkaline flooding. Alkaline flooding is potentially attractive because of the low cost of injected materials and laboratory evidence that oil saturations can be reduced below the waterflood residual level. The basic concept is that low cost alkaline materials (e.g., sodium hydroxide, sodium silicate, sodium carbonate) react with the organic acids contained in some crude oils to produce surfactants capable of reducing oil saturation. They may also react to change the wettability. Field tests to date have been very discouraging. The following are the major technical constraints.

(a) Excessive Consumption. The basic problem is that the injected alkaline fluids react with divalent ions to produce an insoluble precipitate. The result is that an excessive amount of the alkaline material is consumed before it can be propagated deeply into the reservoir. Because of this limitation, alkaline flooding is generally applied in reservoirs

TABLE II-7
CONSTRAINTS FOR ALKALINE FLOODING

CONSTRAINTS	FIELD
Reservoir Heterogeneity	Isenhour Unit (80% of fluids injected into one well)
Injection Control	Isenhour Unit (low injectivity; parting pressure exceeded)
Operations	Isenhour Unit (inadequate data collection/analysis to identify cause of low injectivity/channeling) Wilmington (downhole scale plugging in producers)
Chemical Loss	Wilmington (long-term rock consumption, interaction with high hardness formation brine)
Process Design	Wilmington (high alkaline consumption observed in lab tests prior to injection in field)

containing relatively fresh water. Preflush water is initially injected to remove excessive salinity and hardness. As for micellar-polymer flooding, preflushes have not proved to be effective. Excessive losses were observed in laboratory tests which were used to design the Wilmington field project (Dauben, 1987). The field data indicated very poor propagation.

Laboratory studies indicate that the addition of surfactant and polymer has the potential for reducing the sensitivity of alkaline fluids to salinity and hardness, improving displacement, and improving the sweep efficiency (Olsen, 1990). Additional work is needed to assess the potential of this modified process.

(b) Operational Problems. A major operational problem in alkaline flooding has been the formation of scale in the offsetting producers. This was a problem in Wilmington (Dauben, 1987). Most scale problems can be resolved with periodic scale inhibitor treatments or by the use of acid treatments. However, the occurrence of a barium sulfate scale is serious, since it is insoluble in all acids. Low injectivity and subsequent pressure parting occurred in the Isenhour Unit (Doll, 1986).

Technical Constraints Affecting Gas Injection

Four types of gas injection projects were reviewed. These are CO_2 miscible displacement, CO_2 immiscible displacement, gravity stable displacement, and nitrogen miscible displacement. The technical constraints for the various implemented projects are shown in table II-8. The following are the major technical constraints:

(a) Reservoir Heterogeneity. Reservoir heterogeneities have had one of the most important influences on the performance of gas projects. The high mobility of injected gas is a closely related factor, which together with reservoir heterogeneities, produces poor sweep efficiency. Several field cases are cited. In the Anschutz Ranch East Unit N_2 project, the sweep efficiency was variable within different portions of the unit due both to vertical and areal variations in permeability (Kleinsteiber, 1983). Poor injection profiles were observed in about one-half of the injectors in the Jay-Little Escambia Creek N_2 project due to vertical contrasts in permeability (Langston, 1983). Poor sweep efficiency was observed in the SACROC Unit CO_2 project as indicated by rapid CO_2 breakthrough and poor injection profiles (Kane, 1978). In the West Sussex Unit CO_2 project, one of three producers did not experience response (Holland, 1986).

TABLE II-8
CONSTRAINTS FOR GAS INJECTION

CONSTRAINTS	FIELD
Reservoir Heterogeneity	Anschutz Ranch East Unit N_2 (highly varied sweep due to extreme anisotropy) Ford Geraldine Unit CO_2 (highly variable CO_2 injectivity indicative of reservoir heterogeneity) Garber Field CO_2 (directional flow trends reduced sweep) Jay-Little Escambia Creek N_2 (poor injection profiles in half of injectors) SACROC Unit CO_2 (rapid CO_2 breakthrough; poor injection profiles) West Sussex Unit CO_2 (one of three producers did not experience response)
Corrosion	Bay St. Elaine Field CO_2 (downhole corrosion damage in producers) Bay St. Elaine Field CO_2 (submersible pump problems due to high GOR production)

TABLE II-8, cont'd

CONSTRAINTS	FIELD
	Hawkins Field Unit Flue Gas (corrosion in injection system)
Operations	Lick Creek Meakin Sand Unit, CO_2 Immiscible (oil treating complicated by trapped CO_2; tubing leaks after 3 years injection)
	Means San Andres Unit CO_2 (lift problems in rod and submersible pumps with high GOR production)
	Northeast Purdy Unit CO_2 (downhole corrosion damage in producers)
	Northeast Purdy Unit CO_2 (problems with submersible pumps due to high GOR production)
	Two Freds Project CO_2 (chemical costs to control corrosion were 13% of the total operating budget)
	West Sussex Unit CO_2 (paraffin restriction in producers)
Coning	Intisar "D" Field HC (oil recovery reduced by gas coning)
	Weeks Island CO_2 (gas/water coning contributed to high recycle/injection costs and extended project life)

TABLE II-8, cont'd

CONSTRAINTS	FIELD
Injectivity	Camurlu Field CO_2 (lower than expected injectivity) Ford Geraldine Unit CO_2 (low CO_2 contributing to pattern imbalance and formation pressure parting) Jay-Little Escambia Creek N_2 (water injectivity reduced by WAG injection) Maljamar Field CO_2 (significant reduction in post-CO_2 brine injectivity) Slaughter Estate Acid Gas (low gas injectivity) Two Freds Project CO_2 (low injectivity on west side, requiring use of exhaust gas rather than water as the drive fluid)
Injectant Quality	Camurlu Field CO_2 (hydrate plugging in surface lines)
Injection Control	Ford Geraldine Unit CO_2 (injection above pressure parting level) Intisar "D" Field HC (updip movement of W/O contact, resulting in oil recovery lower than in gas swept zone) Maljamar Field CO_2 (recovery from Ninth Massive San Andres reduced by migration of CO_2 out of the formation) Wilmington CO_2 Immiscible (loss of gas through high permeability, aquifer zone)

TABLE II-8, cont'd

CONSTRAINTS	FIELD
Mobility Control	Lick Creek Meakin Sand Unit, CO_2 immiscible (severe channeling with viscous oil) SACROC Unit CO_2 (Phase I injected started when free gas present and pressures below MMP) Slaughter Estate Acid Gas (rapid breakthrough of nitrogen drive gas even with WAG injection) Wilmington CO_2 Immiscible (gas channeling in zones receiving high injection volume)
Process Design	Little Knife Field CO_2 (project tested only displacement ability of CO_2, but did not test ability of CO_2 to recover oil in a heterogeneous reservoir)

Prudent operators have traditionally attempted to understand the reservoir as completely as practical before initiating a gas injection project. These approaches have included geological studies, pressure transient testing, interwell tracer analysis, history matching of primary and secondary recovery performance, and prediction of future performance. Where reservoir heterogeneities are defined, the prudent operator attempts to arrange patterns and to incorporate procedures (such as the WAG process) to maximize sweep efficiency. Efforts to improve sweep efficiency through the use of materials such as gels and foams have had limited success. In spite of the past efforts, the ability to adequately describe a reservoir for a subsequent gas or other EOR project remains a major technical constraint.

(b) Mobility Control. The high mobility of injected gas is a major cause of the poor sweep efficiency that is observed in many gas projects. Severe channeling was observed when injecting CO_2 into the Lick Creek Meakin Sand Unit, which contains a viscous (160 cP) oil (Reid, 1981). Some success was achieved with the use of a gelled polymer for reducing channeling (Woods, 1986). Rapid breakthrough of nitrogen drive gas occurred in the Slaughter Estate acid gas project even though the WAG process was being utilized (Row, 1981). The rapid breakthrough of CO_2 observed in the SACROC Unit was due in part to the initiation of CO_2 injection at a time when a free gas saturation was present in the reservoir.

The WAG process has been the traditional approach for controlling the mobility of injected gas. However, the benefits of WAG have been questioned both on a technical and economic basis. WAG injection in CO_2 projects necessitates additional investment and expense to maintain corrosion control in the injection wells. Also, Holm's (1988) analysis of 15 CO_2 projects indicated that recoveries were actually higher in projects which did not use WAG injection (Holm, 1988). In scaled laboratory work, Exxon determined that the wetting characteristics of the reservoir influenced whether WAG injection would increase recovery in tertiary corefloods (Jackson et al., 1985). Their tests indicated that continuous CO_2 injection maximized recovery in water-wet cores where gravity override was a significant mechanism. Other tests indicated that the WAG process maximized recovery in oil-wet cores where viscous fingering was a significant factor. Claridge (1981) determined that the WAG process would be beneficial in overcoming some of the adverse effects caused by crossflow in a multi-zoned reservoir.

The apparent disadvantages of the WAG process have prompted a considerable research effort to develop methods for control of the mobility ratio and to improve sweep efficiency. These investigations have included the use of foams, crosslinked polymers, and gels. These research efforts are targeted toward a key technical constraint. However, major considerations in these efforts should be the costs required to achieve the improved mobility control and/or sweep improvement and the impact upon injectivity. As subsequently discussed, low injectivity is a concern in many gas injection projects, especially in carbonate reservoirs. A successfully implemented mobility control treatment in some reservoirs could reduce injectivity to a point where the project would not be economically viable.

(c) Injectivity. Patel (1989) identified nine fields which experienced gas injectivity problems (Patel, 1987). Injected gases in these fields ranged from carbon dioxide to hydrocarbon gas and nitrogen. Although two cases were observed in sandstone reservoirs, the majority of the problems were experienced in carbonate reservoirs. Patel identified wettability and relative permeability effects as the major mechanisms for the reduced injectivities. Other contributing mechanisms included phase behavior effects and inorganic precipitation. In some WAG injection projects, injectivity reductions from 40% (Slaughter Estate) to 60% (Jay-LEC) were experienced (Rowe, 1981; Langston, 1983; respectively). Injectivity reductions were also experienced with continuous gas injection in the Ford Geraldine Unit (Pittaway, 1988). Low water injectivity prevented the use of the WAG process in the Two Freds Project (Kirkpatrick, 1985).

Shell reported that injectivities in their Denver Wasson Unit and South Pine CO_2 projects were significantly different than predicted from laboratory tests (Christman and Gonell, 1988). Although Shell developed a postproject explanation for the observed injectivities, their experience illustrates the uncertainties in predicting the performance that will be achieved in the field.

(d) Operations. Initial concerns were that corrosion costs in CO_2 flooding would be prohibitively expensive. Experience has shown that treatment costs for corrosion control were less than expected but still higher than for waterfloods. Chemical treating costs for the Two Freds CO_2 project represented about 13% of total operational costs (Kirkpatrick, 1985). Costs would have been higher without the beneficial effect of the paraffin which coated the tubing of producing wells. Downhole corrosion problems developed in the Northeast Purdy Unit after breakthrough of CO_2 occurred (Fox, 1986).

Protection of the equipment below the intake of submersible pumps was resolved with the circulation of corrosion inhibitor agents. Corrosion in the injection system was a severe problem in the Hawkins field Unit flue gas project (Carlson). Costs for corrosion control were so high in the East Binger Marchand Unit to prompt the change from flue gas to nitrogen injection.

Artificial lift problems often develop in gas injection projects. The existing artificial lift equipment may become oversized and inefficient after gas breaks through and is being produced in significant quantities. In the Means San Andres Unit, submersible and rod pumps were replaced with jet pumps to handle the gassy fluids (Magruder, 1988). Submersible pumps frequently failed in the Northeast Purdy Unit after breakthrough of injected gas (Fox, 1986). Although the breakthrough of gas can create problems in artificial lift, these can be resolved through proper anticipation and/or reaction to the problems as they develop.

The operations-related constraints primarily affect the costs of the project. Problems can be minimized and costs controlled by the exercise of good project management and the proper utilization of new technology as it is developed.

Technical Constraints Affecting Steam Injection

A review of case histories concentrated on the steamdrive process. The single well injection and production process is normally performed in conjunction with the steamdrive to achieve early production and to stimulate producers to achieve better capture efficiency. The principal technical constraints are shown in table II-9, and discussed as follows:

(a) Gravity Segregation. Gravity segregation appears to be the most predominant problem in the steamdrive process. This problem occurs because of the large density differences between the injected steam and the crude oil. Gravity segregation is also likely to occur when injecting steam into thick sands with high vertical permeability, conditions which are typical of many operations in California. Steam is frequently injected at the base of the pay to partially compensate for the gravity segregation that is anticipated. Also, steam foam techniques have sometimes been used to divert steam into previously unswept areas. In spite of significant industry efforts, gravity segregation remains a major problem which limits oil recovery.

Several field projects are cited. In the Kern River project, a steamdrive operation was conducted in three different expansion areas of varying thickness (Greaser, 1980).

TABLE II-9
CONSTRAINTS FOR STEAM INJECTION

CONSTRAINTS	FIELD
Facilities Design	200 Sand (inadequate steam generation facilities)
	Georgsdorf Field (H_2S/CO_2 generation from steam injection necessitated additional investment in surface facilities)
	Ruehlertwist (surface facilities replaced due to the corrosion caused by produced mixtures of H_2S and CO_2)
Downhole Completion	Brea Field (casing and tubing failures)
Reservoir Heterogeneity	Cat Canyon Field (severe steam channeling, which was aggravated by over-injection)
	El Dorado (very low volumetric sweep)
	Schoonebeek (production response in only a portion of producers)
	Ten Pattern Steamflood (heat front arrival varied from two weeks to two years)
	Winkleman Dome (faults, channels, directional permeability trends)
	Yorba Linda Field (uneven heat flow in reservoir due to silt layers)

TABLE II-9, cont'd

CONSTRAINTS	FIELD
Injectant Quality	Cat Canyon Field (actual sand face steam quality near zero) Georgsdorf Field (low steam quality due to failure of gas insulation in tubing-casing annulus) Schoonebeek (scale plugging of injectors from CO_2 laden gas in the tubing-casing annulus)
Downhole Completion	Cat Canyon Field (sand control; thermal packer failure; inadequate lift capacity) Nacatoch Sand Unit (sand control workovers required when heat front approached producers) Ruehlertwist (frequent workovers in injectors and producers due to thermal effects) Tia Juana Field (21 liner failures, which were related to subsidence)
Reservoir Conditions	El Dorado (excessive heat loss in thin reservoir; low oil saturation at the start of the project) Saner Ranch (fracture treatments required in injectors due to high viscosity of oil)

TABLE II-9, cont'd

CONSTRAINTS	FIELD
Gravity Segregation	Kern River (preferential steam zone flow in the upper sand)
	Ruehlertwist (preferential steam flow in upper portion of sand)
	Schoonebeek (injected steam flowed only in upper one-third of reservoir due to combination of gravity segregation and higher permeabilities)
	Ten Pattern Steamflood (preferential steam flow in the upper sand zone)
	Tia Juana Field (segregated flow within both the Upper and Lower Zones)
	Winkleman Dome (steam flow only in upper portion of sand)

Gravity segregation was most pronounced in the Canfield area where the sand was the thickest. A mechanical procedure to produce oil only from a low set of perforations was successful in reducing produced steam volumes by 90%. Foam treatments to divert injected steam was also considered to be promising. Foam treatments in the Tia Juana steam stimulation project resulted in improved injection profiles (de Haan, 1969). In the Winkleman Dome project, steam flow occurred only in a thin zone at the very top of the pay zone (Pollock, 1969). In spite of the channeling, high recoveries were achieved as a result of the heat transfer which occurred throughout the zone. A similar response was achieved in the Ruehlertwist project (Proyer, 1983). The natural tendency for gravity override was accentuated in the Schoonebeek project by a high-permeability zone at the top of the pay (van Dijk, 1968).

Steam diversion techniques have been extensively investigated in the laboratory and in the field to address the major technical constraint of gravity segregation. Diversion techniques include mechanical procedures, steam foams, polymer gels, and lignosulfonate gels (BETC Staff, 1980; Falls et al., 1988; Chu, 1985, chapter 8, this report). These developments have achieved some limited successes. However, gravity segregation remains a major technical constraint in the steam injection process.

(b) Reservoir Heterogeneity. The effects of reservoir heterogeneities upon performance are similar to those of other processes. As for gas injection processes, the high mobility of steam tends to accentuate an existing reservoir heterogeneity problem.

Several field projects are cited. Severe steam channeling, aggravated by over-injection, occurred in Cat Canyon field (Williams, 1980). The presence of faults, channels, and directional permeability trends limited oil recovery from Winkleman Dome field (Pollock, 1969). In the Ten Pattern Steamflood, the heat front arrival in the various producers ranged from 2 weeks to 2 years (Oglesby, 1980). Poor vertical conformance in the El Dorado project resulted in a volumetric sweep efficiency of about 20% pore volume (Hearn, 1972).

(c) Downhole Completions. The downhole completion of injection and production wells is very important in minimizing the number of mechanical failures and in maintaining control of costs. Common problems include sand control and thermal failure of packers. Although these problems impact costs, the problems are largely resolvable by prudent design and operation of the project.

Several field projects are cited. In the Cat Canyon field, problems include sand control, thermal packer failures, and inadequate lift capacity (Williams, 1980). Workovers to control sand production were required as the heat front approached the producers. Frequent workovers were required in the injectors and producers due to the effects of the high temperatures. In Tia Juana field, liner failures occurred in 21 wells due to subsidence (de Haan, 1969).

(d) Steam Generation. The cost for generating steam is a primary factor in evaluating steamflooding for a new reservoir. The primary factors controlling cost are the price and availability of fuel, pollution control costs, and water-treating costs. Pollution control requirements are of primary concern in some areas. Electrical cogeneration has been used in recent years to reduce unit steam costs through the sale of electricity as a by-product. With conventional boiler technology, steam costs can be reduced only to a certain point. Conventional boiler technology is limited by the quality of the generated steam (80%) and the inherent air pollutants generated when low quality fuels such as coal are used. Because conventional boiler technology generates steam through a heat exchanger process, water treatment costs can become excessive. Alternate technologies such as the wet oxidation process (Balog et al., 1982) offer the potential for significantly reducing unit steam cost since lower quality fuels are used and because feed water can be used to generate a higher quality steam (Balog, 1982). The need for further research and development constrains the use of the wet oxidation technology in steam operations.

Technical Constraints Affecting In Situ Combustion

The reviewed in situ combustion projects include both wet and dry combustion processes, both air and oxygen processes, and pattern and irregular floods. The principal technical constraints for in situ combustion projects are identified in table II-10. The principal constraints have been reservoir heterogeneity and downhole completions. Because of the severe operational problems, there have been few technical and economic successes with in situ combustion technology. The following is a discussion of the major technical constraints:

(a) Reservoir Heterogeneity. Reservoir heterogeneity impacts in situ combustion projects more than any other EOR process. Sweep efficiency is normally low in in situ combustion projects because of the large volumes of noncombustible gas that forms as a

TABLE II-10
CONSTRAINTS FOR IN SITU COMBUSTION PROJECTS

CONSTRAINTS	FIELD
Reservoir Heterogeneity	Bellevue (permeability contrasts between the upper and lower sands)
	Bodcau (uneven combustion front due to varying vertical permeability)
	Brea-Olinda (severe channeling, especially in one block)
	Fry Unit (low sweep in multizoned sand with directional flow trends)
	West Heidelberg (unexpected breakthrough due to areal and vertical permeability variations)
	Midway Sunset (uneven injection into the different sands of a multizone reservoir)
	Miga (severe water channeling prevented wet combustion)
	Sloss (actual permeability one-half of preproject estimate; low sweep efficiency achieved)
	Talco (channeling prior to ignition; Uneven front movement)
	East Tia Juana (production response in only one-half of producers)
	North Ward Estes (natural fracture system distorted flow)
Fluid Containment	Bodcau (significant oil production escaped from project area)

TABLE II-10, cont'd

CONSTRAINTS	FIELD
Reservoir Conditions	Bodcau (actual oil saturation was 54% versus prepilot estimate of 73%) Gloriana (high heat loss resulting from thin sand) South Hospah (oil column was only one-third of expected) Sloss (uncertainties in the oil saturation level before start-up of project) North Ward (insufficient coke/oil saturation to sustain combustion)
Reservoir Description	Brea-Olinda (performance required redrawing fault blocks) Gloriana (three wells found to be isolated from injector) Miga (fault locations were significantly different than anticipated) Trix-Liz (one producer isolated from injector) North Ward Estes (lower oil saturation than anticipated; more extensive fracture system than anticipated)
Injectant Quality	Brea-Olinda (injection well plugging due to lubricant and rust)

TABLE II-10, cont'd

CONSTRAINTS	FIELD
Operations	Forest Hill (future analysis will be difficult with limited monitoring and modeling of complex production history)
	Glen Hummel (excessive casing leaks)
	West Heidelberg (explosion in compression facilities)
	Schoonebeek (in-depth formation plugging caused reduced injectivity and productivity)
	Operations (costs for oil treating and corrosion control were excessive)
	East Tia Juana (corrosion damage in injectors with alternating air/water injection)
Downhole Completion	Fry Unit (high cost of workovers due to age of wells)
	Golden Lake (excessive sand damage in producers)
	Midway Sunset (high temperature damage in both injectors and producers)
	Schoonebeek (producers lost when premature combustion front breakthrough occurred)
	Suplacu de Barcau (formation cratering in injection well near top of sand)
	East Tia Juana (sand erosion in producers)

TABLE II-10, cont'd

CONSTRAINTS	FIELD
Injection Control	Gloriana (initial ignition delayed; insufficient monitoring) Golden Lake (channeling due to injection above parting pressure) South Hospah (combustion front moved down to a waterflooded zone of low oil saturation)
Facilities Design	Golden Lake (inadequate compression facilities; excess downtime) Sloss (design of compression facilities did not permit flexibility in adjusting air-water injection ratios)
Mobility Control	Schoonebeek (premature combustion front breakthrough with free gas saturation at flood start)
Gravity Segregation	Suplacu de Barcau (combustion front swept only upper one third of sand)
Process Design	Talco (inadequate definition of oil saturation prior to project start-up)

result of the combustion process. The gas fingers prematurely through the reservoir and is vented in the offsetting producers. The channels created by these vent gases provide a path of least resistance for the combustion front. The injection of oxygen, rather than air, should reduce the channeling problem since all of the injected gas would be consumed in the combustion process. The use of oxygen would, of course, introduce other potential problems such as increased corrosion and an increased explosion hazard. As shown in table II-10, reservoir heterogeneity was cited as a problem in 11 of the 21 reported projects. The predominate reservoir heterogeneities included vertical permeability contrasts, high-permeability channels, and directional flow preferences. Channeling was especially severe in the West Heidelberg project (Benton, 1981). Initial production occurred in one of the producers located farthest from the injection well. In the Talco project, delayed ignition was attributed to air channeling. At Brea-Olinda, the channeling which limited waterflood recovery also limited recovery from the in situ combustion process (Showalter, 1974). Vertical permeability contrasts reduced recovery in the Bellevue project (Long, 1981), the Bodcau (Bellevue) project (Trantham, 1982), the Fry Unit (Earlougher, 1970), the Midway Sunset project (Gates, 1971), the Sloss project (Parrish, 1974), and the East Tia Juana project (Dietz, 1970). In some of these projects, uneven advancement of the combustion front resulted from the combined effect of both gravity segregation and vertical permeability contrasts.

As a result of these heterogeneities, the combustion fronts often arrive at the producers while a significant portion of the reservoir is still unswept. In most cases, combustion front arrival coincided with loss of the producer. In pattern floods, significant oil was lost when producers were lost. For this reason most of the large projects used either nonuniform well spacing or an advancing linedrive concept. Significant exceptions which used repeating flood patterns were the Bellevue (Long, 1981) and Bodcau (Bellevue) projects (Trantham, 1982) in the United States and the Marguerite Lake (Donnelly, 1985) and Golden Lake Sparky (Fairfield, 1982) projects in Canada. The tendency was to respond to the effects of reservoir heterogeneities in early projects. In later projects, greater planning took place to anticipate the effects of heterogeneities. Accordingly, the nonuniform or advancing linedrive patterns often resulted in extended project lives which decreased their economic potential. As heterogeneity effects are better understood and evaluated, pattern floods will become more prevalent and profitability will improve.

(b) Downhole Completions. The major problems in this category include erosion and corrosion related to sand production in the producers, burnback of the combustion front in the injection wells, and combustion front breakthrough in the producing wells. Sand related problems occurred in the East Tia Juana (Dietz, 1970) and Golden Lake Sparky (Fairfield, 1982) projects.

Injection well burnback occurs when oil flows back into the wellbore. It is most likely to occur early in project life when the combustion front(s) are still near the wellbore. Experience indicates that maintaining uninterrupted injection is a key element in preventing backflow in the wellbore. At Brea-Olinda, limited entry perforations and cooling water circulation were used in the injection wells (Showalter, 1974). Midway Sunset also used cooling water circulation in the injection wells (Gates, 1971). On the producing side, temperature monitoring is critical to detecting the impending arrival of the combustion front. In the Bodcau (Bellevue) project, squeeze treatments were used in zones experiencing early breakthrough along with cooling water circulation (Trantham, 1982). At Marguerite Lake, steam injection was initiated in the producers to prevent further breakthrough (Donnelly, 1985). In this instance, the steam treatments prevented the reoccurrence of breakthrough when the wells were placed back on production. Despite these novel techniques, considerable advancement in downhole completion techniques is still needed before thermal destruction of the wellbores will cease being a technical constraint for in situ combustion projects.

(c) Operations. Corrosion and oil treating are two problem areas in this category which are major technical constraints. These problems are accentuated in the wet combustion process by the combination of organic acids generated by the combustion process and the additional water. Corrosion can also be a problem in injection wells as a result of the short periods of alternating water and air/oxygen injection. Corrosion in producing wells is accelerated when oxygen breakthrough occurs. Corrosion inhibitor requirements become more stringent as the oxygen breakthrough occurs. Emulsions formed by the combustion process are particularly severe. Considerable amounts of chemicals may be required to break the emulsions. Compressor lubricant can also significantly affect economics. If too much lubricant is used, compression costs increase significantly and the risk of either injection well plugging or an explosion in the compression system increases. If not enough lubricant is used, high maintenance costs are incurred in the compression facilities. Even when optimized, lubricant costs are higher with air/oxygen compression than with natural gas because of the compression characteristics of the gases. As a result of the combined effects of corrosion, oil treating, and compressor lubrication, chemical treating costs are inevitably high. These high costs represent a major constraint on the profitability of the in situ combustion process.

Technical Constraints Affecting Microbial Enhanced Oil Recovery

Chapter 5, Part I of this study discusses the state of the art of MEOR processes, including a description of the known technical constraints. A further discussion is provided by Bryant (1989) and by Hitzman (1988). As previously discussed, potential MEOR processes include (1) well stimulation, (2) improved displacement in waterflooding, (3) increased sweep in waterflooding through improved mobility control and/or by selective plugging of high-permeability zones, (4) cleanup of producing wells, and (5) control of coning. Different microorganisms and mechanisms are involved in each of the different applications.

Numerous field tests have been conducted since the 1950s in Europe and in the United States. Most of these tests have concentrated on well stimulation, where results can be quickly evaluated. These results have been encouraging. However, there seems to be a general absence of well documented field tests where results can be clearly documented and assessed. The current field tests conducted by NIPER and the University of Oklahoma will hopefully help to document the field performance of MEOR processes.

A review of field projects will not be provided in this part of the study because of a general absence of definitive tests. However, the currently accepted technical constraints (from chapter 5, Part I) are considered to be:

Parameter	Recommended Range
Salinity	< 15% sodium chloride
Temperature	<170 F
Trace Minerals	<10 ppm arsenic, mercury, nickel, selenium
Permeability	>50 md
Indigenous microorganisms	Compatible with injected microorganisms in selected MEOR process
Crude oil	>15 API
Residual Oil Saturation	25%
Well Spacing	<40 acres

Evaluation Of Industry Research In Addressing EOR Technology Constraints

A database was set up to aid an evaluation of the adequacy of current industry research in addressing the critical technology constraints identified by this study. This database was prepared by reviewing 599 articles published during the period of 1987-1990. Many of the EOR technical constraints were identified from projects that were initiated in the 1970s and early 1980s. The time frame of the data was selected to determine if the recent research and development activities were addressing the identified EOR technical constraints. Most of the publications in the database are from the Society of Petroleum Engineers and the Department of Energy. Publications were those that related to a particular EOR process or to a closely associated technical area.

The database covers the following major areas:

(a) Names of authors of the publications

(b) Names of organizations conducting the research

(c) Types of organizations conducting the research

(d) Organizations providing funding for the research

(e) Technology constraint addressed for each EOR process

The database thus provides essential information on what research is being performed, who is performing the research, and the sources of funds.

Table II-11 shows the total breakout of technical constraints being addressed, broken out by EOR process. Table II-12 lists the technical constraints for the publications which relate directly to each particular EOR process addressed in this study. The chemical processes (polymer, profile modification, micellar-polymer, and alkaline) were combined to be consistent with the presentations in Tables II-3 and II-4.

Figures II-1 through II-5 show a relative percentage comparison of the EOR constraint versus the research efforts which address the problem. This table was derived by first expressing the number of occurrences of the technical constraint for each EOR process, expressed as a percentage of the total. A similar relationship was developed for the research that was performed for each technical constraint. A positive percentage difference in the cited tables indicate that the total relative research effort exceeds the total relative needs for the technical constraint.

Table II-11

Total Database Listing of EOR Constraints
Addressed by the Industry (1987 to 1990)

		Mobility Control	Reserve Heterogeneity	Downhole Completions	Operations	Fluid Containment	Injection Control	Injectant Quality	Facility Design	Process Design	Reservoir Conditions	Reservoir Descriptions	Injectivity	Chemical Consumption	Gravity Segregation	TOTALS
Chemicals	Polymer	18	12	1	2	2	4	3	2	14	6	1	8	8	3	84
	Micellar	6	2	1	5	1	2	2	2	10	2	1	2	9	0	45
	Profile Modification	13	11	0	1	1	7	6	1	13	2	3	9	16	1	84
	Alkaline	1	0	0	0	0	0	0	0	3	0	1	0	4	0	9
	Subtotal-Chemicals	38	25	2	8	4	13	11	5	40	10	6	19	37	4	222
	Gas Injection	51	28	7	13	3	14	12	14	106	10	13	21	11	14	317
	In-situ	1	3	2	2	0	3	1	2	17	1	0	3	0	2	37
	Steam	7	8	7	7	0	12	6	8	35	2	9	4	4	9	118
	Microbial	2	2	1	0	0	1	1	0	9	1	0	0	1	0	18
	General EOR Technology	9	63	9	8	1	26	2	5	58	14	78	21	2	2	298
	TOTALS	108	129	28	38	8	69	33	34	265	38	106	68	55	31	1010

TABLE II-12
DATABASE LISTING OF EOR CONSTRAINTS ADDRESSED BY THE INDUSTRY (1987 - 1990) BY PROCESS*

TYPE OF CONSTRAINT	CHEMICAL	GAS	IN SITU	STEAM	TOTAL
Mobility Control	38	51	1	7	97
Reservoir Heterogeneity	25	28	3	8	64
Downhole Completions	2	7	2	7	18
Operations	8	13	2	7	30
Fluid Containment	4	3	--	--	7
Injection Control	13	14	3	12	42
Injectant Quality	11	12	1	6	30
Facility Design	5	14	2	8	29
Process Design	40	106	17	35	198
Reservoir Conditions	10	10	1	2	23
Reservoir Description	6	13	--	9	28
Injectivity	19	21	3	4	47
Chemical Consumption	37	11	--	4	52
Gravity Segregation	4	14	2	9	29
TOTAL	222	317	37	118	694

* Derived from table II-11

Conversely, a negative percentage difference indicates that inadequate research is being conducted relative to need. The following are the observations made for each process.

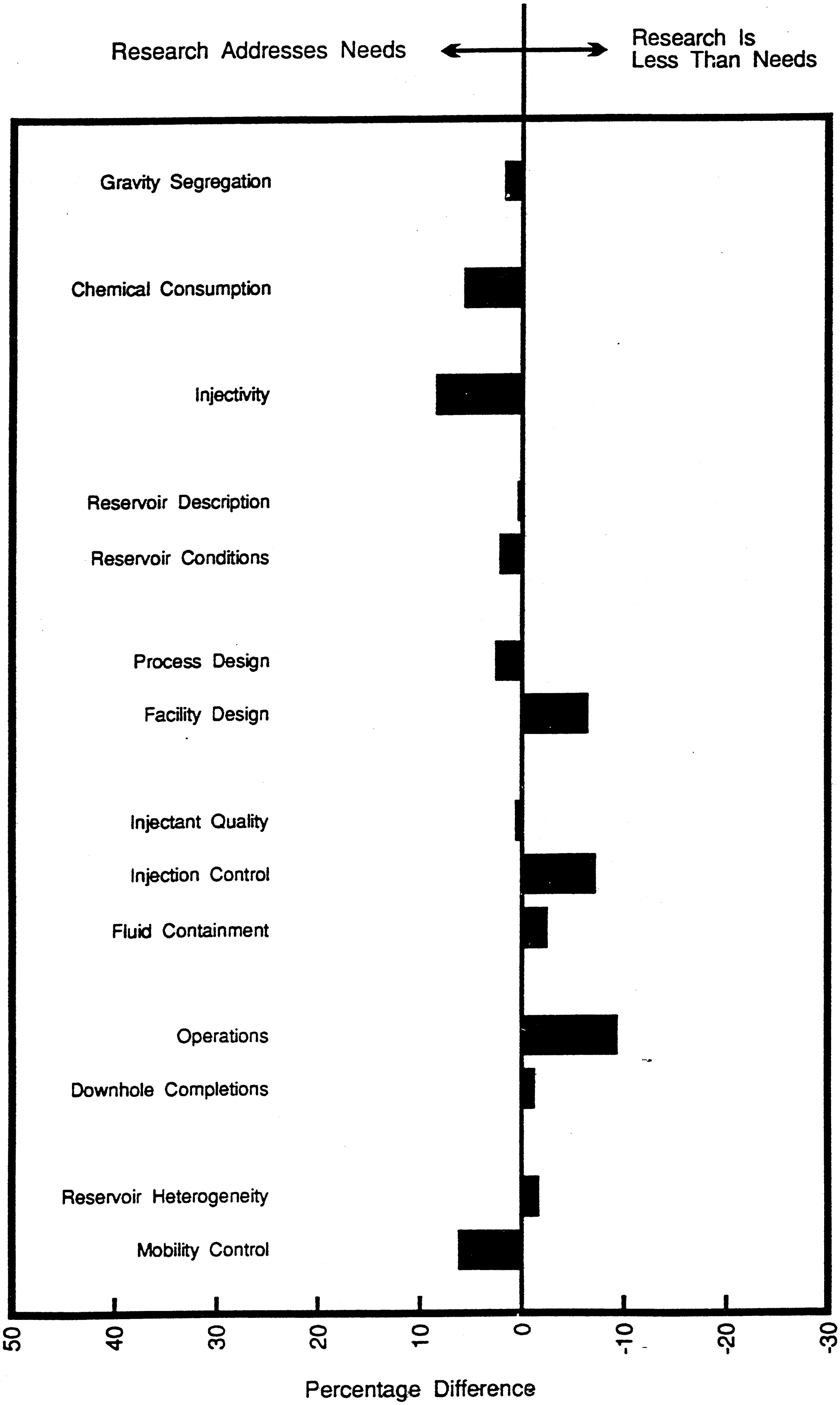
(a) Chemical. Figure II-1 indicates that research is generally being directed at the proper targets. The three areas of significant negative percentages are operations, injection control, and facilities design. These are field-related concerns which are impacted by the number of field tests being conducted and by the financial resources available to properly design and to conduct the project. It is anticipated that these areas will resume their proper importance when field activity increases.

(b) Gas Injection. Figure II-2 indicates low research activities in several field-related constraints, including operations, injection control, and injectivity. The low level of activity reflects partly the low level of new projects being initiated. It may also reflect in part a low activity relative to the need. Reservoir heterogeneity also appears to an area which is not receiving sufficient attention. The large positive activity in process design reflects the numerous modifications being attempted to compensate for the problems inherent within the process (poor sweep, low injectivity).

(c) In Situ Combustion. Figure II-3 indicates several areas of low research activities. One major area is in field-related constraints, including downhole completions and operations. Another major deficiency is in reservoir related areas, including reservoir heterogeneity, reservoir conditions, and reservoir description. As previously discussed, the indicated areas of low research activities correspond to the major problems with in situ combustion. These deficiencies are due in part to the low level of new field projects which are being initiated. The high positive research activity for process design represents modifications which are being evaluated for attempting to correct for inherent problems within the process.

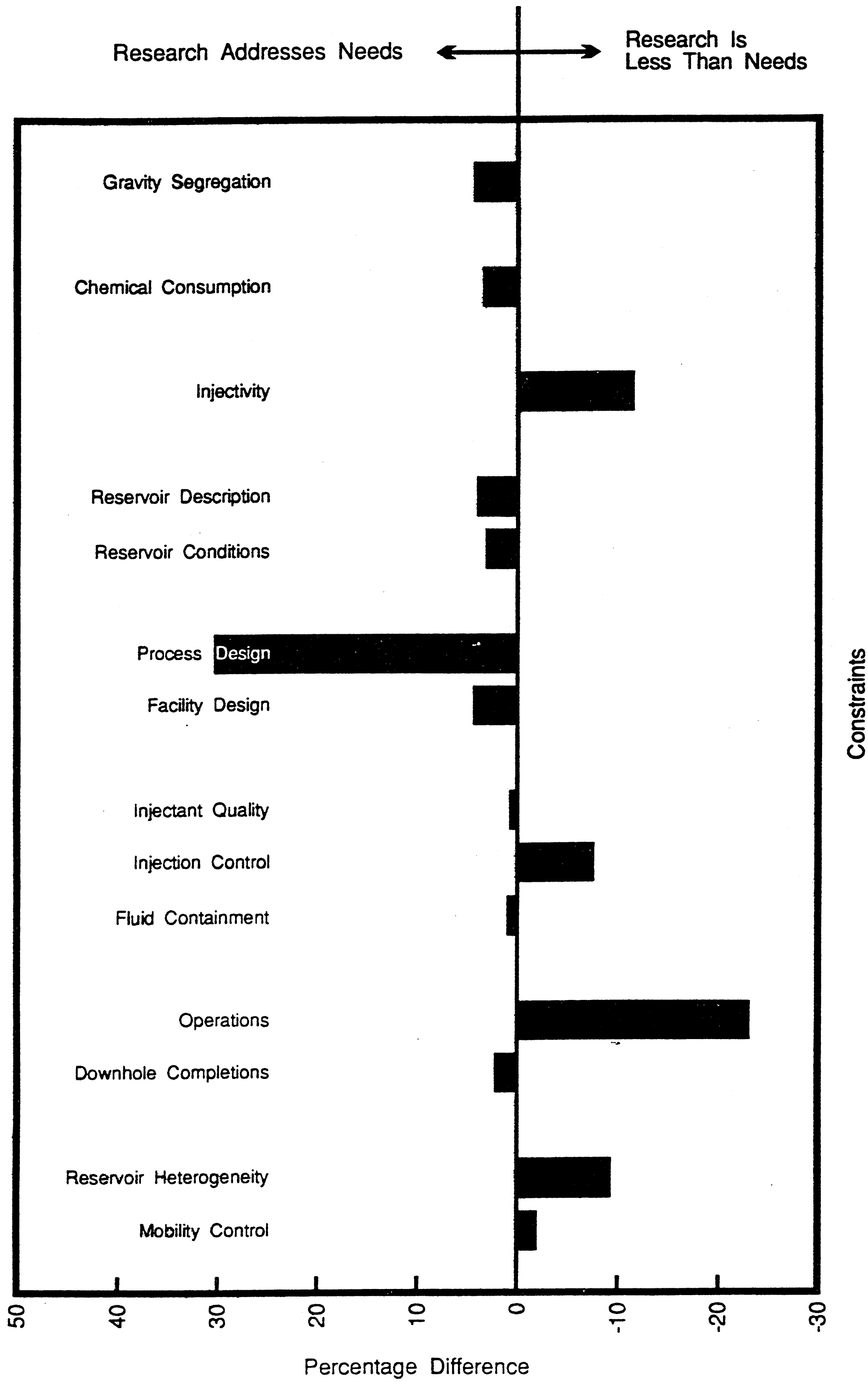
(d) Steam Flooding. Figure II-4 indicates several areas of low research activity. One major area is in operational problems, including downhole completions, injectant quality, and facilities design. Another major area are in reservoir-related problems, including reservoir heterogeneity, reservoir conditions, and gravity segregation. These indicated areas of deficiency represent the major problem areas for steam flooding. The same comments as above apply for the process design area.

FIGURE II-1
COMPARISON OF RESEARCH EFFORTS FOR
CHEMICAL FLOODING WITH INDICATED NEEDS
(Expressed in relative percentages*)



* Derived from tables II-3 and II-12, by expressing all numbers as a percentage of total

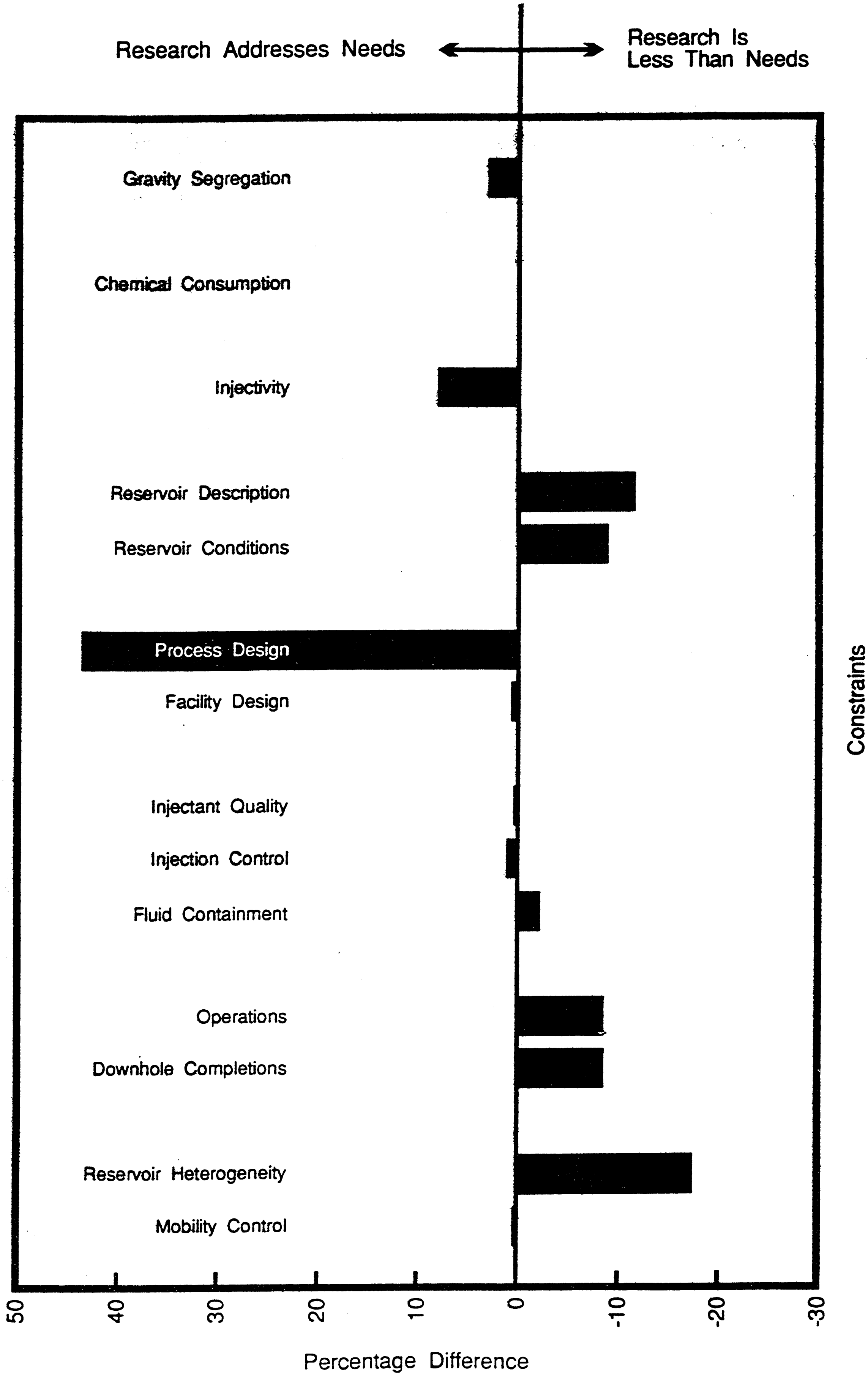
FIGURE II-2
COMPARISON OF RESEARCH EFFORTS FOR
GAS INJECTION WITH INDICATED NEEDS
(Expressed in relative percentages*)



* Derived from tables II-3 and II-12, by expressing all numbers as a percentage of total

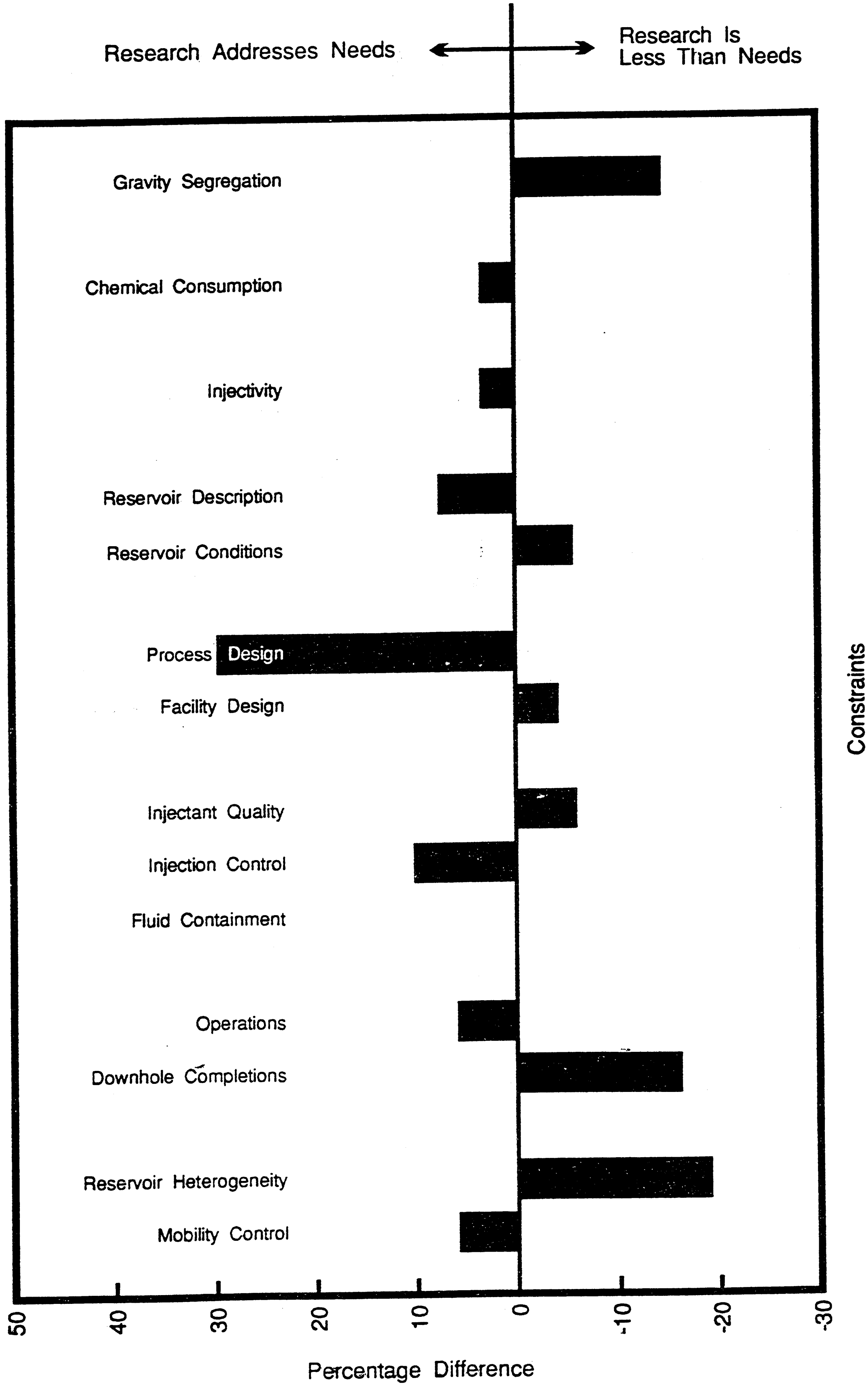
(e) Total Activities. Figure II-5 shows the total combined activity for all of the processes. This figure incorporates the information contained in all of the 599 articles reviewed and summarized in the database. It is considered to be the best indicator of overall needs due to the larger number of data entries used and due to the inclusion of publications which lie in closely related technical areas to EOR. The major indicated needs are in the areas of reservoir heterogeneity and in the closely related areas of downhole completions and operations. Both of these areas are common to all EOR processes. These two broad areas were previously identified to be the major technical constraints which affected all EOR processes.

FIGURE II-3
COMPARISON OF RESEARCH EFFORTS FOR
IN SITU COMBUSTION WITH INDICATED NEEDS
(Expressed in relative percentages*)



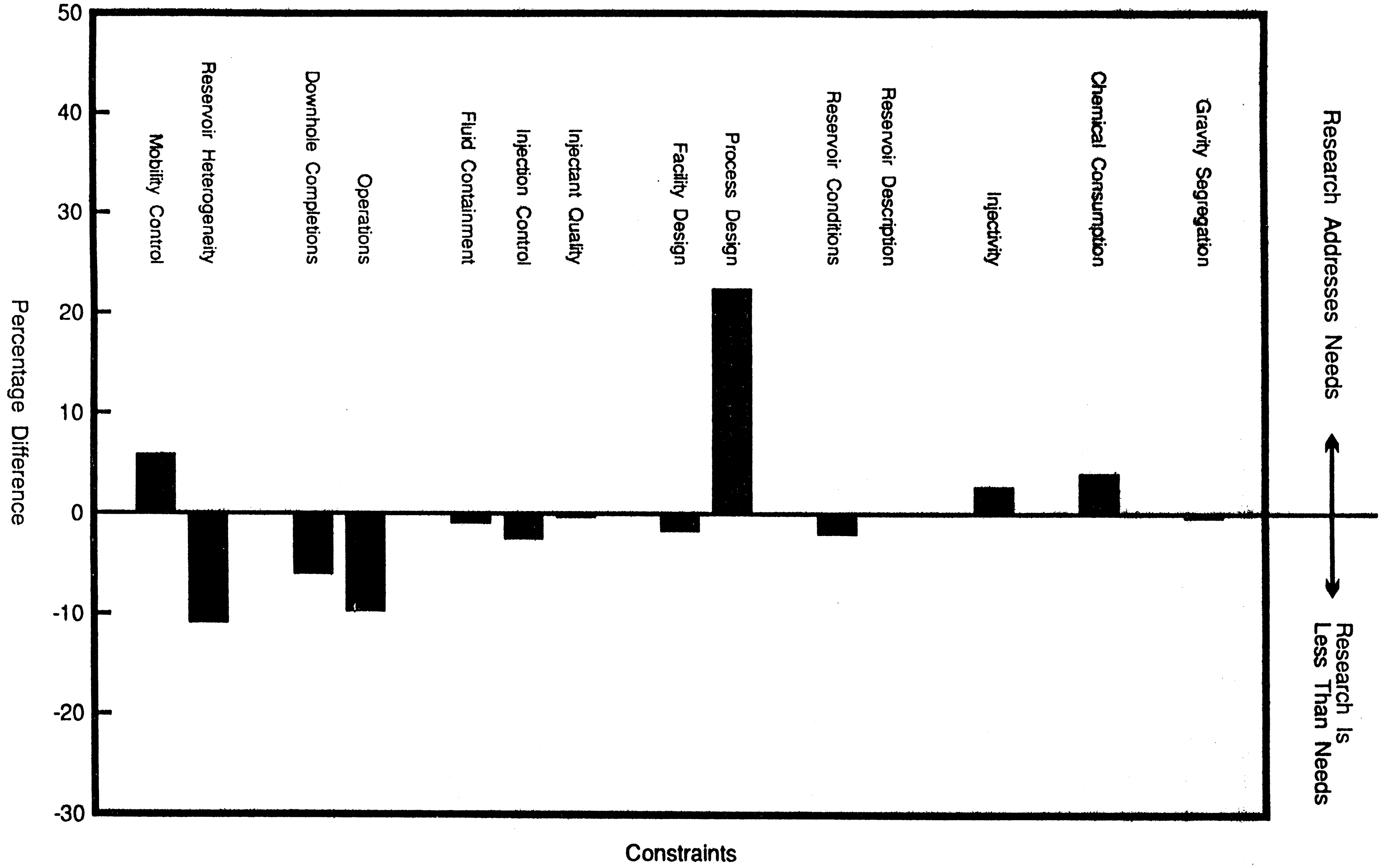
* Derived from tables II-3 and II-12, by expressing all numbers as a percentage of total

FIGURE II-4
COMPARISON OF RESEARCH EFFORTS FOR
STEAM INJECTION WITH INDICATED NEEDS
(Expressed in relative percentages*)



* Derived from tables II-3 and II-12, by expressing all numbers as a percentage of total

FIGURE II-5
COMPARISON OF TOTAL RESEARCH EFFORTS
WITH OVERALL INDICATED NEEDS
(Expressed in relative percentages*)



* Derived from tables II-3 and II-12, by expressing all numbers as a percentage of total

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RESEARCH NEEDS TO MAXIMIZE ECONOMIC PRODUCIBILITY OF THE DOMESTIC OIL RESOURCE

PART II
EOR FIELD CASE HISTORIES

APPENDIX A

CHEMICAL PROJECTS

TABLE OF CONTENTS

CHEMICAL PROJECT--FIELD DATA SUMMARY

Project Name: Bell Creek Project Unit "A" Operator: Gary-Williams Oil Producer, Inc.
Location: Montana Reservoir: Muddy

Project Description
Size of Project: Field (Nine injector-centered 5-spot patterns)

Chemical Process: Micellar-Polymer

Process Design: 0.1 PV alkaline preflush; 0.6% PV micellar water/brine; 3.6% PV of alternating micellar water/micellar oil; 0.4% PV of micellar water/softened water; 1.0 PV of tapered polyacrylamide polymer; drive water to depletion.

Reservoir Depletion at Start: Mature Secondary
Date of First Injection: 02/09/81 Date of Latest Data: 05/01/84

RESERVOIR PARAMETERS--NPC SCREENING CRITERIA

Parameter	NPC CRITERIA			Project Data
	Surfactant	Polymer	Alkaline	
Depth, feet	--	--	--	4,500
Reservoir Temperature, °F	200	200	200	110
Permeability, millidarcy	40	20	20	1,218
Oil Gravity, °API	--	--	30	33
Oil Viscosity, centipoise	40	100	90	6-7
Salinity of Formation Brine, TDS	100,000	100,000	100,000	7,200
Rock Type	SS	SS/CARB	SS	SS

Comments on Reservoir Parameters:

CONSTRAINTS ON EOR RECOVERY
(Listed in order of decreasing significance)

1. Description: Erratic hardness levels in polymer mix water caused fluctuating viscosity levels in polymer slug.
   Classification: Injectant Quality
   Limitation: Technology and Management

2. Description: Facility modifications were required to clean oil from water and to process pit oil.
   Classification: Facility Design
   Limitation: Technology

BELL CREEK MICELLAR-POLYMER PROJECT
CARTER AND POWDER RIVER COUNTIES, MONTANA

DISCUSSION

A 179-acre micellar-polymer flood was conducted in the Muddy sandstone in the Bell Creek Unit "A". The stratigraphic reservoir consists of relatively fine-grained quartzose sand with varying amounts of interbedded sand and shale. Waterflooding which was relatively mature at the start of the project had been successful. Estimated ultimate primary and secondary recovery was about 50% of the original-oil-in-place. Oil recovery in a prior 160-acre micellar-polymer pilot had been about one third of the anticipated amount. Low recovery in the prior pilot was attributed to an unexpected flow barrier between the producers and injectors and the use of a sulfonate with too low an equivalent weight. Recovery estimates in the prior pilot were complicated by inadequate characterization of initial oil saturation and remaining waterflood recovery.

The 179-acre flood was located in a section of the reservoir which was depleted under waterflood. Initially, a 240-acre project had been planned, but data acquired during the drilling phase indicated the reservoir pore volume was 36% larger than previously estimated. Project size was subsequently reduced to a size consistent with the originally planned chemical volumes. Process design was the same as in the prior pilot--a 0.1 pore volume alkaline preflush; a micellar phase consisting of sequential injection of 0.6% pore volume of micellar water/brine, 3.6% pore volume of alternating micellar water/micellar oil, 0.4% pore volume of micellar water/softened water, 1.0 pore volume of a tapered polyacrylamide polymer slug (eight stages); followed by drive water to depletion. Pressure transient testing during the alkaline preflush phase confirmed reservoir continuity. Initial oil saturation in the project area was estimated at 33%, based on field-derived relative permeability data and the observed 2.7% oilcut in the producers (although the area had previously been watered-out, infill drilling and pattern modification). Total project recovery was estimated at about 16% of the oil-in-place at start of the flood. From an economic standpoint, the overall results were not sufficiently promising to warrant further expansion.

The primary operational problem was maintaining consistent softening levels in the softening facility. Since polymer viscosity correlated with hardness levels in the supply water, constant attention was required, and short periods of viscosity fluctuation were known to have occurred. One injection well was ultimately lost due to gelled polymer buildup. Its replacement well also experienced reduced injectivity after plugging off when 27 centipoise polymer solution was injected. Some difficulty was encountered in oil treating. Facility modifications were made to increase residence time in the water cleanup section; pit oil treating was accomplished with a centrifuge.

SIGNIFICANCE OF PROJECT

Reservoir data from the infill wells drilled for the project resulted in a significant revision of pore volume. The importance of continuously updating reservoir description with new data cannot be overemphasized.

CHEMICAL PROJECT--FIELD DATA SUMMARY

Project Name: Big Muddy
Location: Converse County, Wyoming
Operator: Conoco
Reservoir: 2nd Wall Creek

Project Description
Size of Project: Field (Twelve 5-spot patterns)
Chemical Process: Micellar-Polymer
Process Design: 0.1 PV preflush; 0.1 PV micellar slug, 0.4 PV tapered polymer slug (prematurely discontinued).

Reservoir Depletion at Start: Mature Secondary
Date of First Injection: 02/01/80
Date of Latest Data: 06/01/87

RESERVOIR PARAMETERS--NPC SCREENING CRITERIA

Parameter	NPC CRITERIA Surfactant	Polymer	Alkaline	Project Data
Depth, feet	--	--	--	3,100
Reservoir Temperature, °F	200	200	200	115
Permeability, millidarcy	40	20	20	52
Oil Gravity, °API	--	--	30	34
Oil Viscosity, centipoise	40	100	90	5.5
Salinity of Formation Brine, TDS	100,000	100,000	100,000	7,800
Rock Type	SS	SS/CARB	SS	SS

CONSTRAINTS ON EOR RECOVERY
(Listed in order of decreasing significance)

1. Description: Uncontrolled fluid ingress/egress from reservoir due to behind-pipe communication; fracture network.
   Classification: Fluid Containment
   Limitation: Technology and Management

2. Description: Injection at pressures above the formation-parting pressure resulted in the micellar slug being bypassed by polymer.
   Classification: Injection Control
   Limitation: Management

3. Description: Incomplete investigation of velocity/viscosity effects caused viscosity over design; contributed to low injectivity.
   Classification: Process Design
   Limitation: Technology and Management

BIG MUDDY DEMONSTRATION PROJECT WYOMING

DISCUSSION

A commercial scale low-tension flood (micellar-polymer) demonstration project was conducted in the Second Wall Creek Reservoir in the Big Muddy Field in east central Wyoming. The approximately 90-acre project offsets a one-acre pilot where Conoco initially evaluated the low-tension flood process. The cost-shared, low-tension flood used a 0.1 pore volume preflush and a 0.1 pore volume low-tension slug, followed by a polymer drive bank. The sulfonate used in the low-tension slug was a blend of both low and high molecular weight synthetic sulfonates. Dow Pusher 500, a dry polyacrylamide polymer, was used in both the low-tension slug and polymer drive bank for mobility control.

Preflush injection started in February 1980. Respective start dates for the low-tension and polymer drive banks were January 1981 and August 1982. Although the designed volumes of preflush and low-tension slug were injected, the polymer drive bank was prematurely discontinued in September 1985, due to low injectivity and deteriorating production performance. By September 1985, oil production had declined from a peak of 220 barrels of oil per day in late 1983 to about 90 barrels of oil per day. When the cost-sharing project terminated in mid-1987, nearly half of the project producers had been shut in for economic reasons. Production from the remaining producers was about 75 barrels of oil per day at an oilcut of 3.5%. Project oil production through May 1987 was about 290,000 barrels. Estimated ultimate oil recovery to an economic limit at a 1% oilcut is 390,000 barrels or about 14% of the oil-in-place at the start of the project.

Although project oil recovery was/will be significantly less than originally predicted, the low-tension process successfully mobilized waterflood residual oil. The primary factor contributing to lower than anticipated recovery was lack of containment of the injected fluids in the reservoir. Behind-pipe communication in abandoned or reconditioned wellbores in the project area represented the most probable source of fluid migration from the reservoir. 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. Because injectivity restricted injection rates, the mobility of the initial 20 centipoise low-tension slug was lower than required to match the minimum mobility in the reservoir. Although viscosity of the slug was subsequently reduced, improved injectivity was never realized in field operations.

Low injectivity led to injection at pressures above the estimated formation-parting pressure during the polymer drive phase. As a result, the oil banks which had been formed were not effectively displaced to the producers.

SIGNIFICANCE OF PROJECT

The deleterious effect of uncontrolled fluid movement on oil recovery in the Big Muddy project demonstrates the importance of monitoring and controlling fluid movement in enhanced recovery processes.

CHEMICAL PROJECT--FIELD DATA SUMMARY

Project Name: El Dorado
Location: Butler County, Kansas

Operator: Cities Service
Reservoir: Admire

Project Description
Size of Project: Pilot (Two adjacent patterns testing alternate formulations)
Chemical Process: Micellar-Polymer
Process Design: North Pilot: 0.4 PV of 1.4% NaCl preflush; 0.4 PV of controlled salinity preflush; 0.1 PV of micellar-polymer; 0.73 PV of graded biopolymer-polyacrylamide; drive water. South Pilot: 0.15 PV of 2% NaCl preflush; 0.17 PV alkaline preflush; .06 PV soluble oil-micellar water; 0.9 PV graded polymer slug.

Reservoir Depletion at Start: Mature Secondary
Date of First Injection: 11/01/75
Date of Latest Data: 04/01/82

RESERVOIR PARAMETERS--NPC SCREENING CRITERIA

Parameter	NPC CRITERIA Surfactant	Polymer	Alkaline	Project Data
Depth, feet	--	--	--	
Reservoir Temperature, °F	200	200	200	69
Permeability, millidarcy	40	20	20	265
Oil Gravity, °API	--	--	30	37
Oil Viscosity, centipoise	40	100	90	5
Salinity of Formation Brine, TDS	100,000	100,000	100,000	87,000
Rock Type	SS	SS/CARB	SS	SS

Comments on Reservoir Parameters:

CONSTRAINTS ON EOR RECOVERY
(Listed in order of decreasing significance)

1. Description: Inadequate or incorrect description of rock constituents led to error in oil saturation estimate; known indications of fluid migration prior to project.
   Classification: Process Design
   Limitation: Technology and Management

2. Description: Rock constituents/salinity-hardness levels caused high surfactant losses.
   Classification: Chemical Consumption
   Limitation: Technology

3. Description: Extraneous fluid entry from known pressure gradient was confirmed by brine monitoring.
   Classification: Fluid Containment
   Limitation: Technology and Management

EL DORADO MICELLAR-POLYMER PILOT PROJECTS
BUTLER COUNTY, KANSAS

DISCUSSION

Two different micellar processes were employed in adjacent 25 acres in the El Dorado Field. The Chesney (north) pilot used a high water content micellar fluid, while the Hegberg (south) pilot used the soluble oil/micellar water Uniflood process. Results were disappointing in that measurable incremental oil was not recovered in either pilot. Postproject analysis revealed that several factors contributed to the failure of the micellar processes.

1. Rock description. Preproject rock/mineralogy description failed to identify both the thin mica layers distributed at 1- to 4-inch intervals in the rock and the presence of significant quantities of gypsum. The subsequently detected mica layers provided a high degree of microstratification which influenced the oil saturation in individual layers. The gypsum content contributed significantly to chemical consumption. Produced water analyses also indicated the presence of abundant barium content. The nearly unlimited ion exchange potential of the reservoir, if correctly identified, would have negated the salinity/hardness-sensitive micellar formulations used in the pilot. Retrospective evaluation of core flood results reveals the limited effectiveness of the micellar formulation in the reservoir environment.

2. Oil saturation. Initial oil saturation was estimated at 40% based on log calculations, even though relative permeability data indicated a likely waterflood residual oil level of 26%. Since the resolution of logging techniques is less than the thickness of the strata created by the mica layers, the oil saturation represents an average value. With vastly differing permeability in the micro-strata, actual oil saturation in the permeable zones which were flooded approached the residual oil levels indicated by relative permeability data rather than 40% indicated by logging. As a result, the actual moveable oil at project start was significantly less than anticipated. These low oil saturations were intimated by prior EOR pilots.

3. Fluid Migration. Concentrated trends of chlorides and hardness and a known pressure gradient across the field suggest that significant amounts of extraneous water entered the pilot areas. This extraneous water entry distorted fluid flow and contributed to salinity/hardness problems.

Sufficient data existed to warrant further investigation of the above parameters prior to the project, rather than waiting until the project had failed.

SIGNIFICANCE OF PROJECT

Failure of the micellar-polymer pilots at El Dorado emphasizes the consequences of overlooking negative data during the project design stage.

CHEMICAL PROJECT--FIELD DATA SUMMARY

Project Name: Loudon 2nd Pilot Operator: Exxon
Location: Fayette County, Illinois Reservoir: Weiler Sand

Project Description
Size of Project: Pilot (0.7 acres, 5-spot pattern)
Chemical Process: Micellar-Polymer
Process Design: 0.40 PV micellar slug; 0.75 PV of 35 cP biopolymer; 2.25 PV of graded biopolymer slug.

Reservoir Depletion at Start: Mature Secondary
Date of First Injection: 05/13/80 Date of Latest Data: 07/01/82

RESERVOIR PARAMETERS--NPC SCREENING CRITERIA

Parameter	NPC CRITERIA Surfactant	Polymer	Alkaline	Project Data
Depth, feet	--	--	--	1,550
Reservoir Temperature, °F	200	200	200	78
Permeability, millidarcy	40	20	20	150
Oil Gravity, °API	--	--	30	34
Oil Viscosity, centipoise	40	100	90	5
Salinity of Formation Brine, TDS	100,000	100,000	100,000	104,000
Rock Type	SS	SS/CARB	SS	SS

CONSTRAINTS ON EOR RECOVERY
(Listed in order of decreasing significance)

1. Description: Bacterial contamination after 0.65 PV of polymer injection resulted in loss of mobility control thereafter.
   Classification: Mobility Control
   Limitation: Technology

2. Description: Uneven distribution of injection between Upper and Lower sands, particularly in one quadrant.
   Classification: Reservoir Heterogeneity
   Limitation: Technology

LOUDON SALT-TOLERANT SURFACTANT PILOT
FAYETTE COUNTY, ILLINOIS

DISCUSSION

Exxon developed a salt-tolerant surfactant formulation for the Weiler Sand reservoir in the Loudon Field after low recovery was experienced in an earlier pilot which used a low salinity preflush/petroleum sulfonate system. The new formulation was designed to be effective in the presence of the highly saline formation water (104,000 ppm TDS). The project consisted of a single 0.68-acre, 5-spot pattern using four injection wells and a central producer. Monitoring was facilitated by five logging observation wells and one postproject core well. Fluid injection consisted of 0.4 pore volume of micellar slug, 0.75 pore volume of 35 centipoise biopolymer slug, and 2.25 pore volume of graded biopolymer slug. Volume of the polymer slug was increased from the originally planned 0.8 pore volume when bacterial contamination at about 0.65 pore volume of polymer injection caused a loss of viscosity control. In-situ polymer degradation was subsequently traced to a two-week period. Unfortunately, only a short period of contamination can cause enduring degradation in-situ.

Despite the loss of mobility control, the process recovered about 60% of the oil-in-place at start of the flood. Recovery would have been even higher if the injected fluids had been evenly distributed between the upper and lower sand intervals. In one quadrant, monitoring indicated the injected fluids flowed only in the lower interval, even though early profiles had indicated the entire interval was taking fluid. Cause of the changed injection profile was unknown.

SIGNIFICANCE OF PROJECT

High recovery in the Loudon salt-tolerant surfactant pilot test indicates that greater potential lies with surfactant formulation than with reservoir preflushing in adverse salinity environments.

CHEMICAL PROJECT--FIELD DATA SUMMARY

Project Name: Loudon 2nd Ripley Surfactant Flood Test
Location: Fayette County, Illinois

Operator: Exxon
Reservoir: Weiler Sand

Project Description
Size of Project: Pilot (0.71 acres, 5-spot pattern)
Chemical Process: Micellar-Polymer
Process Design: 0.30 PV micellar slug containing biopolymer; 1 PV of 38 cp biopolymer; brine injection.

Reservoir Depletion at Start: Mature Secondary
Date of First Injection: 08/07/82 Date of Latest Data: 11/01/83

RESERVOIR PARAMETERS--NPC SCREENING CRITERIA

Parameter	NPC CRITERIA			Project Data
	Surfactant	Polymer	Alkaline	
Depth, feet	--	--	--	1,400-1,600
Reservoir Temperature, °F	200	200	200	78
Permeability, millidarcy	40	20	20	154
Oil Gravity, °API	--	--	30	34
Oil Viscosity, centipoise	40	100	90	5
Salinity of Formation Brine, TDS	100,000	100,000	100,000	104,000
Rock Type	SS	SS/CARB	SS	SS

CONSTRAINTS ON EOR RECOVERY

(Listed in order of decreasing significance)

1. Description: High retention of the injected biopolymer.
   Classification: Chemical Consumption
   Limitation: Technology

LOUDON SECOND RIPLEY SURFACTANT TEST
FAYETTE COUNTY, ILLINOIS

DISCUSSION

Exxon conducted a second pilot in the Loudon Field to further develop a surfactant flood process, which had earlier been successful in displacing oil in a high salinity environment. The earlier pilot resulted in the recovery of 60% of the in-place oil, but problems had been encountered in the degradation of the biopolymer and in the separation of the produced oil-brine emulsions. The second pilot was conducted with several objectives: (a) Evaluate the impact on oil recovery of injecting a smaller surfactant slug volume (0.30 PV compared to 0.40 PV), (b) Demonstrate that formaldehyde is an effective biocide for the biopolymer (in contrast to the dibromo dinitrilo propionamide used earlier), and (c) Develop and evaluate cost-effective techniques for breaking oil-brine-surfactant emulsions.

The second surfactant test resulted in another successful demonstration of good oil recovery in a high salinity environment. The project led to the recovery of 68% of the in-place oil, low surfactant retention, and the cost-effective separation of the produced emulsions. The biopolymer was successfully protected from degradation by the formaldehyde, but experienced poor propagation. The poor propagation did not impact recovery in this small pilot, but could create problems in the larger distances involved in a commercial size operation.

SIGNIFICANCE OF PROJECT

This second test conducted in the Loudon Field with surfactants designed to tolerate high salinity and hardness again demonstrates the technical viability of designing the chemical system for the reservoir environment rather than preflushing to change the ionic environment of the reservoir.

CHEMICAL PROJECT--FIELD DATA SUMMARY

Project Name: Manvel Field
Location: Brazoria County, Texas
Operator: Texaco
Reservoir: Frio

Project Description
- Size of Project: Pilot (Two injectors, three producers)
- Chemical Process: Micellar-Polymer
- Process Design: 0.25 PV surfactant slug; 0.5 PV polymer consisting of 0.17 PV at 1,700 ppm biopolymer, tapered to zero over 0.33 PV.

Reservoir Depletion at Start: Depleted Waterdrive
Date of First Injection: 06/01/77
Date of Latest Data: 11/01/79

RESERVOIR PARAMETERS--NPC SCREENING CRITERIA

Parameter	NPC CRITERIA Surfactant	Polymer	Alkaline	Project Data
Depth, feet	--	--	--	5,400
Reservoir Temperature, °F	200	200	200	165
Permeability, millidarcy	40	20	20	500
Oil Gravity, °API	--	--	30	29
Oil Viscosity, centipoise	40	100	90	4
Salinity of Formation Brine, TDS	100,000	100,000	100,000	107,000
Rock Type	SS	SS/CARB	SS	SS

CONSTRAINTS ON EOR RECOVERY
(Listed in order of decreasing significance)

1. Description: Injected fluids flooded additional zone because shale barrier was non-sealing.
   Classification: Injection Control
   Limitation: Technology

2. Description: Pressure pulse tests after project started confirmed all wells not in communication due to previously undetected fault.
   Classification: Reservoir Description
   Limitation: Management

3. Description: Premature drive water breakthrough caused, in part, by polymer degradation.
   Classification: Mobility Control
   Limitation: Technology

MANVEL FIELD PILOT
BRAZORIA COUNTY, TEXAS

DISCUSSION

The Manvel Field pilot was conducted in a watered-out sand interval in Fault Block 3. Since the Frio sandstone reservoir had produced by strong waterdrive, the estimated oil saturation at the start of the micellar-polymer pilot was about 30%. A petroleum sulfonate-cosurfactant micellar solution containing a lignosulfonate sacrificial agent to reduce surfactant adsorption losses was developed. The surfactant formulation caused significant interfacial tension reductions, even in the presence of the high salinity reservoir brine (107,000 mg/1 TDS). Final process design consisted of 0.25 pore volume of this micellar solution. The surfactant slug was driven by 0.5 pore volume biopolymer slug in a mixture of 20% reservoir brine/80% fresh water. Polymer concentration was kept at 1,700 ppm for 0.17 pore volume and then tapered to zero over 0.33 pore volume. Biopolymer was used in the mobility control slug because of its higher salinity tolerance. The same water mix was used to displace the polymer bank. Tracers were injected during the micellar and drive water injection phases.

Postflood analysis indicated that tertiary oil was recovered in only one of three producers. The lack of response in two of the three wells was attributed to the injected fluids flooding an underlying sand interval along with the intended sand interval. Geologic review indicated the shale break between the sands was an ineffective barrier. Pressure pulse tests also identified a previously unknown fault which contributed to out-of-zone communication. The single producer which did experience production response was found to be in communication with one injector but isolated from other injectors and producers.

Displacement analysis in this portion of the reservoir signified that only 37% of the oil displaced by the micellar solution was captured by the producer. Low recovery was attributed to breakthrough of the drive water slug which stopped further displacement and to oil displacement to areas where there were no producers. Analysis indicated that steadily increasing polymer degradation was partially responsible for the loss of mobility control. Surfactant retention in those areas swept was about 39 pounds per barrel of oil recovered. Even with improved sweep efficiencies, the observed surfactant retention level was considered prohibitive.

SIGNIFICANCE OF PROJECT

Low oil recovery in the Manvel project can be primarily attributed to fluid flow patterns being significantly different than anticipated. The preproject reservoir description failed to detect the nonsealing nature of the shale barrier or the fault which separated the project area.

CHEMICAL PROJECT--FIELD DATA SUMMARY

Project Name: North Burbank Unit, Micellar-Polymer Project — Operator: Phillips
Location: Osage County, Texas — Reservoir: Burbank

Project Description
Size of Project: Pilot (90 acres - nine inverted 5-spot patterns)
Chemical Process: Micellar-Polymer
Process Design: 0.41 PV controlled salinity preflush; 0.05 PV of micellar slug; 0.47 PV graded polyacrylamide polymer slug; drive water to depletion.

Reservoir Depletion at Start: Mature Secondary
Date of First Injection: 12/01/75 — Date of Latest Data: 01/01/82

RESERVOIR PARAMETERS--NPC SCREENING CRITERIA

Parameter	NPC CRITERIA Surfactant	Polymer	Alkaline	Project Data
Depth, feet	--	--	--	2,900
Reservoir Temperature, °F	200	200	200	120
Permeability, millidarcy	40	20	20	50
Oil Gravity, °API	--	--	30	39
Oil Viscosity, centipoise	40	100	90	3
Salinity of Formation Brine, TDS	100,000	100,000	100,000	87,000
Rock Type	SS	SS/CARB	SS	SS

Comments on Reservoir Parameters:

CONSTRAINTS ON EOR RECOVERY
(Listed in order of decreasing significance)

1. Description: High surfactant adsorption due to adverse salinity/hardness and oil-wetting characteristics of rock.
   Classification: Chemical Consumption
   Limitation: Technology

2. Description: Well stimulations during polymer injection and injection above parting pressure resulted in the micellar slug being bypassed by polymer.
   Classification: Injection Control
   Limitation: Management

NORTH BURBANK UNIT MICELLAR-POLYMER PROJECT
OSAGE COUNTY, OKLAHOMA

DISCUSSION

The micellar-polymer project in the North Burbank Unit was implemented under known adverse conditions. The adverse conditions included: (a) high salinity/hardness levels, (b) fractures with east-west directional orientation, (c) oil-wet rock, and (d) low injectivity which would probably require injection at pressures above the formation-parting pressure. The oil-wetting characteristics of the reservoir not only decreased recovery but increased surfactant adsorption. Although the preflush which consisted of 1.4 million barrels of fresh water followed by 1.0 million barrels of fresh water with 15,000 ppm NaCl added was designed to condition the reservoir, produced brine monitoring through the flood life indicated the salinity/hardness levels were still well above the desired level. In retrospect, an alternative controlled salinity preflush may have been more effective. High sulfonate losses were ultimately identified as the cause of low recovery--about half of that expected. High sulfonate losses were attributed to both the oil-wetting characteristics and the adverse salinity.

During the project, injectivity/productivity during the polymer injection period was low as anticipated. Although minifracs increased productivity/injectivity, they also created channeling problems. In some instances, injection pressures above the formation-parting pressure were still required. Net effect of the minifracs and induced fractures from overpressuring was for the polymer slug to bypass the micellar slug (and oil bank). Production response indicated that slug bypassing occurred. Initially, rapid response from micellar displacement of the permeable channels was evident. At a later date, significantly lower response from polymer displacement in other zones occurred. Tracer results confirmed the partial slug bypassing in new flow channels. In selected cases, gelled polymer treatments were used with partial success to control excessive channeling.

SIGNIFICANCE OF PROJECT

Observed flow trends illustrate the importance of performing fracture treatments at the start of the project and of operating at pressures below the formation-parting pressure.

CHEMICAL PROJECT--FIELD DATA SUMMARY

Project Name: Robinson M-1 — Operator: Marathon
Location: Crawford County, Illinois — Reservoir: Robinson

Project Description
- Size of Project: Field (407 acres; 2.5- and 5.0-acre spacing)
- Chemical Process: Micellar-Polymer
- Process Design: 0.1 PV micellar slug; 1.05 PV tapered polyacrylamide; drive water to depletion.

Reservoir Depletion at Start: Mature Secondary
Date of First Injection: 02/10/77 — Date of Latest Data: 01/01/87

RESERVOIR PARAMETERS--NPC SCREENING CRITERIA

Parameter	NPC CRITERIA Surfactant	Polymer	Alkaline	Project Data
Depth, feet	--	--	--	950
Reservoir Temperature, °F	200	200	200	--
Permeability, millidarcy	40	20	20	103
Oil Gravity, °API	--	--	30	36
Oil Viscosity, centipoise	40	100	90	7
Salinity of Formation Brine, TDS	100,000	100,000	100,000	40,000
Rock Type	SS	SS/CARB	SS	SS

CONSTRAINTS ON EOR RECOVERY
(Listed in order of decreasing significance)

1. Description: Low volumetric sweep due to permeability stratification and random directional flow preferences.
   Classification: Reservoir Heterogeneity
   Limitation: Technology

2. Description: Inadequate consideration of salinity/hardness levels of original formation brine; surfactant effectiveness limited by salinity/hardness.
   Classification: Process Design
   Limitation: Technology and Management

3. Description: Treating costs at peak sulfonate levels approached $2 per barrel of oil.
   Classification: Operations - Oil Treating
   Limitation: Technology and Management

ROBINSON M-1 PROJECT
CRAWFORD COUNTY, ILLINOIS

DISCUSSION

A commercial scale micellar-polymer project was conducted in the Robinson Sand of the M-1 project in southwestern Illinois. The project utilized a crude oil sulfonate surfactant system to flood the reservoir which, at the time of the project, was in an advanced stage of waterflood depletion. Marathon applied the experience they had gained in several similar projects in the Illinois basin. Process design included a 0.10 PV micellar slug followed by a 1.05 pore volume graded polyacrylamide polymer slug. The project was developed in two areas with different spacing--2.5-acre and 5.0-acre--to allow economic comparison with different development spacing. Overall project recovery was slightly over 20% of the oil-in-place at start of the flood. Although recovery in the 2.5-acre spacing area was slightly greater than in the 5.0-acre spacing area, the additional recovery did not support the additional development expense.

Poor volumetric sweep efficiency contributed significantly to the lower than anticipated tertiary recovery. Volumetric sweep was adversely affected by permeability stratification, formation-parting due to injection overpressuring, and random channels of communication between injectors and producers. Salinity monitoring of produced brine indicated that micellar fluids were exposed to higher than anticipated salinity/hardness levels. As a result, the effectiveness of the petroleum sulfonate system was probably reduced. The brine produced after years of waterflooding exhibited a total dissolved solids content of 16,500 mg/1 and a calcium content of 166 mg/1. Higher salinity and, probably, hardness were present in the original connate water which had been diluted by years of waterflooding with a mixture of supply water and produced water. Producers drilled in areas not under waterflood influence exhibited chloride concentrations equivalent to approximately 40,000 mg/1 total dissolved solids. Hardness levels were not measured. From an operational standpoint, oil treating and bacteria control were the predominant problems. At peak sulfonate levels, oil-treating costs approached $2 per barrel. Although oil treating and bacteria chemical treating increased operating costs, adequate control was obtained.

SIGNIFICANCE OF PROJECT

Reservoir heterogeneities controlled project recovery even though development spacing in a portion of the project was as small as 2.5 acres.

CHEMICAL PROJECT--FIELD DATA SUMMARY

Project Name: Salem Unit
Location: Marion County, Illinois

Operator: Texaco
Reservoir:

Project Description
Size of Project: Pilot (Twelve 5-acre, inverted 5-spot patterns)
Chemical Process: Micellar-Polymer
Process Design: 0.18 PV surfactant slug; .015 PV water pad; 0.81 PV constant to tapered biopolymer slug; 0.20 PV fresh water pad; field brine to depletion.

Reservoir Depletion at Start: Mature Secondary
Date of First Injection: 08/01/81
Date of Latest Data: 04/01/85

RESERVOIR PARAMETERS--NPC SCREENING CRITERIA

Parameter	NPC CRITERIA Surfactant	Polymer	Alkaline	Project Data
Depth, feet	--	--	--	1,750
Reservoir Temperature, °F	200	200	200	72
Permeability, millidarcy	40	20	20	125
Oil Gravity, °API	--	--	30	36
Oil Viscosity, centipoise	40	100	90	3.6
Salinity of Formation Brine, TDS	100,000	100,000	100,000	117,000
Rock Type	SS	SS/CARB	SS	SS

CONSTRAINTS ON EOR RECOVERY
(Listed in order of decreasing significance)

1. Description: Despite stimulation treatments, fluid flow primarily in lower zone.
   Classification: Reservoir Heterogeneity
   Limitation: Technology

2. Description: Bacterial contamination degraded polymer slug resulting in loss of mobility control.
   Classification: Mobility Control
   Limitation: Technology

3. Description: Oil-treating costs up to $9 per barrel until facility modifications made.
   Classification: Facility Design
   Limitation: Technology and Management

SALEM UNIT 60-ACRE MICELLAR-POLYMER PROJECT
MARION COUNTY, ILLINOIS

DISCUSSION

A 12-pattern, 60-acre micellar-polymer project was conducted in the Benoist Sandstone in the Salem Field using a salt-tolerant micellar formulation. A salt-tolerant formulation was used because of the varying, but high, salinities encountered in the reservoir (30,000-70,000 mg/1 TDS). Oil recovery in a prior pilot using a less salt-tolerant formulation had been less than one third of that expected. Low recovery in the earlier pilot also resulted from lack of containment of the injected fluids. The 60-acre pilot discussed herein addressed these problems by using a salt-tolerant formulation and by containing injected fluids to the project area with 24 surrounding injectors.

The Benoist Sand in the project area consists of a distinct upper and lower interval. Preproject log analysis indicated that prior waterflooding had preferentially depleted the more permeable lower zone. As a result, the oil saturation in the lower zone was 28%, as compared to 36% in the upper zone. Although minifrac treatments were performed in the injection wells to increase fluid volumes entering the upper zone, process monitoring indicated that nearly all of the injected micellar-polymer fluids stayed in the lower zone. Despite the poor injection profile, project oil recovery was about 47% of the oil-in-place. Monitor observation wells confirmed the effectiveness of the salt-tolerant formulation in the flooded lower zone. High recovery occurred despite loss of mobility control in the polymer slug due to bacterial degradation. Although bacterial control in the polymer slug with alternative chemical treatments, Texaco estimated that the first 70% of the polymer slug lost its viscosity. Sweep efficiency was also reduced by knowingly allowing injection pressures to exceed the formation-parting pressure.

SIGNIFICANCE OF PROJECT

Acceptable oil recovery was realized in a high salinity reservoir environment by using a salt-tolerant micellar-polymer process. Good recovery was experienced even with known poor mobility control in the polymer slug.

CHEMICAL PROJECT--FIELD DATA SUMMARY

Project Name: Sloss Micellar Pilot — Operator: Amoco
Location: Kimball County, Nebraska — Reservoir: Muddy J

Project Description
- Size of Project: Pilot (9-acre, 5-spot pattern)
- Chemical Process: Micellar-Polymer
- Process Design: 0.05 PV preflush brine to raise salinity; 0.15 PV micellar slug; 0.65 PV graded polyacrylamide slug (terminated early).

Reservoir Depletion at Start: Mature Secondary
Date of First Injection: 02/26/77 — Date of Latest Data: 05/01/80

RESERVOIR PARAMETERS--NPC SCREENING CRITERIA

Parameter	NPC CRITERIA			Project Data
	Surfactant	Polymer	Alkaline	
Depth, feet	--	--	--	6,300
Reservoir Temperature, °F	200	200	200	200
Permeability, millidarcy	40	20	20	80
Oil Gravity, °API	--	--	30	
Oil Viscosity, centipoise	40	100	90	0.8
Salinity of Formation Brine, TDS	100,000	100,000	100,000	2,500
Rock Type	SS	SS/CARB	SS	SS

CONSTRAINTS ON EOR RECOVERY
(Listed in order of decreasing significance)

1. Description: Initial bare steel polymer injection system and improper mixing facilities caused injection well plugging.
   Classification: Facility Design
   Limitation: Management

2. Description: Stimulation treatments to remove injection well plugging degraded polymer which caused loss of mobility control.
   Classification: Mobility Control
   Limitation: Technology

SLOSS MICELLAR PILOT
KIMBALL COUNTY, NEBRASKA

DISCUSSION

Although the salinity/hardness levels of the reservoir brine in the Muddy J reservoir were not adverse, the 200° F reservoir temperature was at the upper limit for polymer stability. The micellar-polymer process was initiated after thermal stability tests indicated the polymer would be stable for up to three years at 200° F in an oxygen-free environment. The process design included a small volume preflush to raise reservoir salinity, a 0.15 pore volume micellar slug, and a graded polyacrylamide slug for mobility control. When tracer data during the preflush stage conflicted with predicted flow trends, the reservoir geological model was reviewed. Upon further review, it was determined that the flow behavior observed in earlier waterflooding and determined that the flow behavior observed in earlier waterflooding and in-situ combustion projects, as well as with the tracers in the pilot, was due to different depositional environments, rather than directional permeability. The flow behavior in the pilot was related to proximity to and orientation of the different depositional environments. Once again, the project illustrated the importance of continuously updating the reservoir description as new data is obtained.

Early project performance was promising. Postproject analysis demonstrated deteriorating performance in later life (project was prematurely terminated after 0.65 pore volume of polymer slug) was due to degradation of the polyacrylamide polymer. Polymer injection proceeded smoothly for the first two months. At that point, a substantial decline in injectivity occurred as a result of formation plugging from iron sulfide and unhydrated polymer. Although hypochlorite-acid treatments temporarily improved injectivity, plugging kept occurring until bare steel surface facilities were plastic-coated and revised bacterial treatments were initiated. Postproject analysis indicated that the well cleanup treatments were primarily responsible for the deteriorating performance in late life.

Although polymer degradation by the well cleanup treatments was the direct cause of poor performance, the well treatments would not have been required if injectant quality had been maintained. Since the technology for maintaining polymer quality was available at the time of the project, project failure is management related rather than technology related. Additional postproject laboratory work exhibited adverse ion exchange phenomena may have also contributed to lower than desired displacement efficiency with the sulfonate micellar slug.

SIGNIFICANCE OF PROJECT

The primary cause of project failure could have been avoided with proper emphasis on maintaining injectant quality.

CHEMICAL PROJECT--FIELD DATA SUMMARY

Project Name: West Burkburnett
Location: Wichita County, Texas

Operator: Mobil Oil
Reservoir: Gunsight Sand

Project Description
Size of Project: Field (Ten 20-acre, 5-spot patterns)
Chemical Process: Micellar-Polymer
Process Design: 0.02 PV fresh water preflush; 0.15 PV pretreat to reduce surfactant adsorption; 0.15 PV surfactant with pretreat chemicals; 0.1 PV of 500 ppm biopolymer; 0.2 PV tapered polymer, fresh water to depletion.

Reservoir Depletion at Start: Mature Secondary
Date of First Injection: 11/10/73 Date of Latest Data: 01/01/81

RESERVOIR PARAMETERS--NPC SCREENING CRITERIA

Parameter	NPC CRITERIA Surfactant	Polymer	Alkaline	Project Data
Depth, feet	--	--	--	1,800
Reservoir Temperature, °F	200	200	200	85
Permeability, millidarcy	40	20	20	75
Oil Gravity, °API	--	--	30	35
Oil Viscosity, centipoise	40	100	90	--
Salinity of Formation Brine, TDS	100,000	100,000	100,000	150,000
Rock Type	SS	SS/CARB	SS	SS

CONSTRAINTS ON EOR RECOVERY
(Listed in order of decreasing significance)

1. Description: Incomplete characterization of polymer injectivity versus permeability.
   Classification: Process Design
   Limitation: Management and Technology

2. Description: Excessive consumption of sacrificial chemical slug.
   Classification: Chemical Consumption
   Limitation: Technology

3. Description: Formation pressure parting during polymer injection phase contributed to micellar slug bypassing.
   Classification: Injection Control
   Limitation: Management

WEST BURKBURNETT LOW TENSION WATERFLOOD (LTWF) PROJECT WICHITA COUNTY, TEXAS

DISCUSSION

The low tension waterflood (LTWF) project was conducted in a portion of the reservoir which was depleted under waterflood operations. The process design used a small fresh water preflush plus a sacrificial chemical slug to displace the high salinity reservoir brine and condition the reservoir rock. The 10-pattern project recovered about one fourth of the oil originally projected. Postproject analysis attributed the low oil recovery to two factors--higher than anticipated sacrificial chemical consumption and formation pressure parting during the polymer injection phase.

Comparative logging runs at an observation well located 200 feet from an injector indicated that the LTWF process initially formed an oil bank. At a further distance from the injection wellbore, less oil bank was observed. Postflood consumption analysis indicated the sacrificial chemicals were consumed shortly beyond the 200-foot radius. At that point, excessive surfactant consumption occurred with associated poor displacement. Postflood saturation analysis from core wells confirmed that displacement efficiency decreased at large distances from the injector.

Postflood injectivity testing in core samples also revealed that the polymer slug could not be successfully injected in samples with permeability less than 100 md. Since only one fourth of the net sand interval exhibited permeabilities greater than 100 md, the oil saturation stratification observed in the core wells was caused by the polymer injectivity-permeability relationship. Pressure transient tests indicated that injection well fracture lengths increased significantly during the polymer injection phase. As a result of this observed formation pressure parting, portions of the polymer slug bypassed the surfactant slug. Portions of the oil which had been banked by the surfactant were not displaced to the producers.

SIGNIFICANCE OF PROJECT

The combination of excessive chemical consumption and polymer bypassing of the surfactant slug due to formation pressure parting decreased oil recovery to about one fourth of preproject estimates.

CHEMICAL PROJECT--FIELD DATA SUMMARY

Project Name:	Coalinga Polymer Projects	Operator:	Shell Oil
Location:	Wichita County, Texas	Reservoir:	Temblor Zone II

Project Description
- Size of Project: Pilot (149 acres, four inverted 5-spot patterns)
- Chemical Process: Polymer-Mobility Control
- Process Design: Inject 300 ppm slug of Kelzan MF biopolymer.

Reservoir Depletion at Start: Mature Secondary
Date of First Injection: 05/01/78 Date of Latest Data: 10/01/80

RESERVOIR PARAMETERS--NPC SCREENING CRITERIA

Parameter	NPC CRITERIA			Project Data
	Surfactant	Polymer	Alkaline	
Depth, feet	--	--	--	2,000
Reservoir Temperature, °F	200	200	200	100
Permeability, millidarcy	40	20	20	50-480
Oil Gravity, °API	--	--	30	--
Oil Viscosity, centipoise	40	100	90	25
Salinity of Formation Brine, TDS	100,000	100,000	100,000	2,000-4,000
Rock Type	SS	SS/CARB	SS	SS

CONSTRAINTS ON EOR RECOVERY
(Listed in order of decreasing significance)

1. Description: Misinterpretation of reservoir drive mechanism led to significant error in estimating oil saturation - 39% versus preproject estimate of 54%.
   Classification: Reservoir Conditions
   Limitation: Management

2. Description: Injection well plugging by unhydrated polymer/bacterial debris.
   Classification: Injectant Quality
   Limitation: Management

3. Description: Biopolymer injection was initiated despite low injectivity/plugging problems evident in preproject injectivity testing.
   Classification: Process Design
   Limitation: Management

COALINGA POLYMER DEMONSTRATION PROJECT
FRESNO COUNTY, CALIFORNIA

DISCUSSION

The Coalinga polymer demonstration project was designed to show the relative merits of water and polymer flooding in a reservoir with medium viscosity oil. Located in the East Coalinga Field, Fresno County, California, the 149-acre project area contained four 22-acre, inverted 5-spot injection patterns. The target reservoir was a 350-foot thick, unconsolidated sandstone formation at about 2,000 feet. Although the preflood analysis considered the reservoir to be producing via gravity drainage, the watercut was at 80% at the start of the project. It was later discovered that dump flooding from other zones was occurring. The resulting areal variations in salinity contributed to the preproject estimate of oil saturation being considerably higher than what was observed--54% versus an actual estimated saturation of 39%. Following nearly two years of water injection and an extensive field polymer injectivity and filtration study, polymer injection into four injection wells began in May 1978. The production response to polymer injection was less than expected, and the project was terminated early.

Postproject analysis identified two major factors responsible for poor performance. Firstly, the inadequate interpretation of oil saturation had allowed the pilot to be conducted in an area where little moveable oil was present. Also, biopolymer injection proceeded despite early indications that wellbore plugging would occur. Low injectivity plagued the injection operations.

SIGNIFICANCE OF PROJECT

Management constraint were the major factor responsible for the poor performance of this mobility control, polymer flood.

CHEMICAL PROJECT--FIELD DATA SUMMARY

Project Name: Hitts Lake Unit
Location: Smith County, Texas
Operator: Sun Oil
Reservoir: Paluxy
Project Description
Size of Project: Field
Chemical Process: Polymer-Mobility Control
Process Design: Inject 0.25 PV graded (five steps) polymer slug; drive water to depletion.

Reservoir Depletion at Start: Mature Primary
Date of First Injection: 10/01/80
Date of Latest Data: 04/01/84

RESERVOIR PARAMETERS--NPC SCREENING CRITERIA

Parameter	NPC CRITERIA Surfactant	Polymer	Alkaline	Project Data
Depth, feet	--	--	--	7,250
Reservoir Temperature, °F	200	200	200	210
Permeability, millidarcy	40	20	20	300
Oil Gravity, °API	--	--	30	26
Oil Viscosity, centipoise	40	100	90	2.7
Salinity of Formation Brine, TDS	100,000	100,000	100,000	105,000
Rock Type	SS	SS/CARB	SS	SS

Both reservoir temperature and salinity of the formation brine are extremely adverse for polymer flooding.

CONSTRAINTS ON EOR RECOVERY
(Listed in order of decreasing significance)

No constraint.

HITTS LAKE UNIT POLYMER PROJECT
SMITH COUNTY, TEXAS

DISCUSSION

Reservoir conditions at the start of polymer injection were extremely adverse. Reservoir temperature was above the accepted temperature limit for polymers, plus the gas saturation was about 25%. The high gas saturation resulted from good primary production and a prior gas injection project which had been discontinued. Prior to the gas injection project, a pilot waterflood had been discontinued due to premature water breakthrough. To ensure that polymer viscosity in the formation would reach the desired 6 centipoise level, slug viscosity at the plant was intentionally overdesigned and a rigorous quality control program was established. Viscosity of the polymer slug was graded from 82 to 25 centipoise over 0.25 pore volume of injection. No premature breakthrough problems have been observed as in the waterflood. Although injection profiles are poor, sweep efficiency in the zones being flooded has improved. After three years of operation, production has doubled and is still increasing.

SIGNIFICANCE OF PROJECT

Close attention to surface quality control and overdesign of the polymer slug viscosity have contributed to apparent polymer success in this high temperature, high salinity environment.

CHEMICAL PROJECT--FIELD DATA SUMMARY

Project Name: North Burbank Unit — Operator: Phillips
Location: Osage County, Oklahoma — Reservoir: Burbank

Project Description
- Size of Project: Field (1,440 acres)
- Chemical Process: Polymer
- Process Design: Fresh water injection, followed by the injection of 4,170,000 pounds polyacrylamide and 4,020,000 pounds of aluminum citrate.

Reservoir Depletion at Start: Mature Waterflood
Date of First Injection: 09/29/80 — Date of Latest Data: 03/31/90

RESERVOIR PARAMETERS--NPC SCREENING CRITERIA

Parameter	NPC CRITERIA			Project Data
	Surfactant	Polymer	Alkaline	
Depth, feet	--	--	--	2,900
Reservoir Temperature, °F	200	200	200	120
Permeability, millidarcy	40	20	20	50
Oil Gravity, °API	--	--	30	39.5
Oil Viscosity, centipoise	40	100	90	3
Salinity of Formation Brine, TDS	100,000	100,000	100,000	87,000
Rock Type	SS	SS/CARB	SS	SS

CONSTRAINTS ON EOR RECOVERY

(Listed in order of decreasing significance)

1. Description: Reduced injectivity in water disposal wells due to carryover oil and polymer.
   Classification: Operations
   Limitation: Technology

NORTH BURBANK UNIT POLYMER FLOOD PROJECT

DISCUSSION

A fresh water polymerflood covering 1440 acres was implemented in 1980 in Block A of the North Burbank Field. Fresh water was initially injected to displace the resident formation water so that greater effectiveness could be achieved with the subsequently injected polyacrylamide polymers and aluminum citrate solutions. A total of 4,170,000 pounds of polymer and 4,020,000 pounds of aluminum citrate were injected into in the reservoir during the course of the project. The sequential injection of polymer and aluminum citrate were effective in increasing the flow resistance of injected fluids and improving the sweep efficiency. An estimated 2,500,000 STB of oil was recovered from the reservoir during the project.

Several operational considerations are noteworthy. First, the injection of fresh water itself greatly increased the costs of the project as well as environmental concerns in using large volumes of fresh water. The necessity to inject the fresh water suggests that improvements are needed in chemical systems that can tolerate the higher salinity and hardness environment typical of many reservoirs. Second, the injectivities of individual wells were lower than had been anticipated. A total injection rate of 50,000 bbl/day resulted during polymer injection compared to 63,000 bbl/day that had been anticipated. Aluminum citrate was not injected in some of the wells due to the lower than anticipated injectivities. Third, the disposal of produced water was more difficult than anticipated due to the plugging caused by carryover oil and polymer. This problem was resolved by the re-routing of produced water into additional disposal wells in other portions of the field.

An alternative chemical system using polyacrylamide and chromium propionate is now being developed for a 160-acre project in North Burbank because of the indicated effectiveness of this chemical system for the higher salinity waters. Laboratory tests indicate that this chemical system should be more effective than the aluminum citrate system in achieving in-depth flow resistance in reservoirs containing a more saline water. Thus, the need for injecting a preflush bank of fresh water would be eliminated. Presumably, this project is in progress.

SIGNIFICANCE OF PROJECT

This project has demonstrated the technical feasibility of sequentially injecting polyacrylamide and aluminum citrate to recover significant of oil on a commercial basis. The need for polymer systems to operate within the existing ionic environment of the reservoir is demonstrated by this project.

CHEMICAL PROJECT--FIELD DATA SUMMARY

Project Name: North Stanley Polymer Operator: Gulf Oil
Location: Osage County, Oklahoma Reservoir: Stanley
Project Description
Size of Project: Field (1,000 acres)
Chemical Process: Polymer-Mobility Control
Process Design: 0.06 PV fresh water preflush; 0.17 PV graded polymer slug with average concentration of 285 ppm.

Reservoir Depletion at Start: Mature Secondary
Date of First Injection: 06/01/76 Date of Latest Data: 01/01/81

RESERVOIR PARAMETERS--NPC SCREENING CRITERIA

Parameter	NPC CRITERIA			Project Data
	Surfactant	Polymer	Alkaline	
Depth, feet	--	--	--	2,900
Reservoir Temperature, °F	200	200	200	105
Permeability, millidarcy	40	20	20	10-1,000
Oil Gravity, °API	--	--	30	--
Oil Viscosity, centipoise	40	100	90	2.4
Salinity of Formation Brine, TDS	100,000	100,000	100,000	--
Rock Type	SS	SS/CARB	SS	SS

CONSTRAINTS ON EOR RECOVERY

(Listed in order of decreasing significance)

1. Description: Extreme permeability variations and natural fracture system caused poor sweep efficiencies.
   Classification: Reservoir Heterogeneity
   Limitation: Technology

2. Description: Operating above the formation-parting pressure contributed to channeling; breakdown of gelled polymer treatments.
   Classification: Injection Control
   Limitation: Management

NORTH STANLEY POLYMER DEMONSTRATION PROJECT
OSAGE COUNTY, OKLAHOMA

DISCUSSION

Production from the Stanley interval in the North Burbank unit is from three zones of vastly differing flow capacity. Permeability ranges from greater than 1000 md in the Upper Burbank to 100-300 md in the Lower Burbank to less than 10 md in the Bartlesville Sand. The Bartlesville Sand also contains an extensive natural fracture system, especially in the lower portion. Strong directional flow trends were observed during waterflood. When the polymer project was started, waterflooding was in a mature state with a WOR of 75. Considering the known extreme heterogeneities, the combined primary and secondary recovery of 38% of the original-oil-in-place was quite good.

During the fresh water preflush state (.06 pore volume), extensive remedial work was performed on the injection wells. Additional intervals were perforated and gelled polymer treatments were performed in half of the project injectors. Profile surveys indicated significant improvements as a result of these treatments. A graded polymer slug with an average concentration of 285 ppm was injected over a year period. First response to polymer injection occurred in two months with peak response five months later. Within two years after the start of polymer injection, unit production had resumed the typical waterflood decline. The rapid but short-lived production response indicated most of the incremental recovery was related to injection profile improvements from either the workovers or gelled polymer treatments rather than from mobility control within individual strata. Significant channeling was observed during the polymer injection stage. In several cases, channeling was correlated with injecting at pressures above the formation-parting pressures. There were some indications that some of the gelled polymer treatments may have broken down with time. If injection had been maintained below the formation-parting pressure, the positive effects of the improved injection profiles would have been sustained for a longer period of time.

SIGNIFICANCE OF PROJECT

Although mobility control polymer slug was injected in the North Stanley project, the bulk of the incremental recovery was associated with improved injection profiles from either well workovers or gelled polymer treatments.

CHEMICAL PROJECT--FIELD DATA SUMMARY

Project Name: Oerrel Field   Operator: Deutsche Texaco
Location: Germany   Reservoir: Dogger-Beta
Project Description
Size of Project: Pilot
Chemical Process: Polymer-Mobility Control
Process Design: 18.2% PV fresh water preflush; 12% PV of 1,500 ppm polymer; 9% tapered slug; fresh water drive to depletion.

Reservoir Depletion at Start: Mature Primary
Date of First Injection: 04/01/75   Date of Latest Data: 01/01/81

RESERVOIR PARAMETERS--NPC SCREENING CRITERIA

Parameter	NPC CRITERIA Surfactant	Polymer	Alkaline	Project Data
Depth, feet	--	--	--	4,600
Reservoir Temperature, °F	200	200	200	136
Permeability, millidarcy	40	20	20	100-4,000
Oil Gravity, °API	--	--	30	25
Oil Viscosity, centipoise	40	100	90	19
Salinity of Formation Brine, TDS	100,000	100,000	100,000	167,000
Rock Type	SS	SS/CARB	SS	SS

Fresh water preflush used to control adverse effects of high salinity reservoir brine.

CONSTRAINTS ON EOR RECOVERY
(Listed in order of decreasing significance)

1. Description: Mixing facility modifications were required to preclude the injection well plugging initially observed.
   Classification: Facility Design
   Limitation: Management

OERREL FIELD GERMANY

DISCUSSION

The polymer pilot was conducted in the upper zone of the Dogger-Beta Sand in the Middle Fault Block. Primary oil production via a moderate water drive was approaching the estimated ultimate recovery of 25% of the original-oil-in-place. Watercut in the stratified reservoir was about 80%. Slug design included an 18% pore volume fresh water preflush to displace the highly saline reservoir brine. Shortly after polymer injection was started, a rapid increase in injection pressure due to formation plugging resulted in the injection well being shut in. The well was subsequently fracture stimulated after modifications had been made to the polymer mixing facility. Subsequent injectivity was maintained without difficulty.

Within six months of initial injection, watercut stabilized. The watercut remained constant for two years before beginning a gradual increase. With polymer response in a mature state, WOR projections indicate an ultimate recovery of about 40% of the original-oil-in-place. Incremental recovery from polymer injection is about 15% of the original-oil-in-place.

SIGNIFICANCE OF PROJECT

Preflush injection enabled a successful polymer flood to be conducted in a reservoir containing a highly saline brine (167,000 mg/1).

CHEMICAL PROJECT--FIELD DATA SUMMARY

Project Name: Sleepy Hollow Reagan Unit
Operator: Amoco
Location: Red Willow County, Nebraska
Reservoir: Reagan

Project Description
Size of Project: Field (10 injectors, 45 producers)
Chemical Process: Polymer-Mobility Control
Process Design: Inject about 50% PV 800 ppm polyacrylamide in fresh water, taper to drive water.

Reservoir Depletion at Start: Mature Secondary
Date of First Injection: 02/14/85 Date of Latest Data:01/01/88

RESERVOIR PARAMETERS--NPC SCREENING CRITERIA

Parameter	NPC CRITERIA Surfactant	Polymer	Alkaline	Project Data
Depth, feet	--	--	--	3,500
Reservoir Temperature, °F	200	200	200	100
Permeability, millidarcy	40	20	20	2,580
Oil Gravity, °API	--	--	30	31
Oil Viscosity, centipoise	40	100	90	24
Salinity of Formation Brine, TDS	100,000	100,000	100,000	32,050
Rock Type	SS	SS/CARB	SS	SS

Comments on Reservoir Parameters:

Fresh water used in polymer slug had TDS concentration of about 700 mg/1.

CONSTRAINTS ON EOR RECOVERY
(Listed in order of decreasing significance)

1. Description: Earlier than anticipated production response indicative of reservoir heterogeneity; injectivity reductions from 10% to 70%.
   Classification: Reservoir Heterogeneity
   Limitation: Technology and Management

2. Description: Near wellbore plugging in producers required solvent treatments to maintain productivity.
   Classification: Operations-Formation Plugging
   Limitation: Technology

3. Description: Rod failures doubled when producers experienced polymer breakthrough.
   Classification: Operations-Corrosion
   Limitation: Technology

SLEEPY HOLLOW REAGAN UNIT
RED WILLOW COUNTY, NEBRASKA

DISCUSSION

The Reagan Sand in the Sleepy Hollow Reagan unit is an unconsolidated, homogeneous sandstone with minimal clay content. Polymer flooding was started in 1985 in the high permeability (2,580 md) sand to improve the flood mobility ratio (oil viscosity=24 centipoise). The high permeability of the reservoir, clean sand, and abundant fresh water supply for injection favored a polymer flood. Since the available core samples from the edges of the field exhibited much lower permeability, initial slug design used sandpacks made from either crushed core or produced sand. When lower than anticipated injectivity was experienced in a field injectivity test, the molecular weight of the polymer was reduced in the final slug design.

Although the project is in too early a stage (0.4 pore volume of polymer slug) for final conclusions, several factors appear to be constraining oil recovery. Reservoir heterogeneity is worse than anticipated. Earlier than anticipated production response and injectivity reductions ranging from 10 to 70% are indicative of major areal and vertical permeability variations. On a long-term basis, these effects serve to reduce oil recovery. Two operations-related constraints are increasing operating costs. Corrosion-related rod failures have doubled in those wells which have experienced polymer breakthrough. Polymer breakthrough also causes decreased productivity in the producers due to suspected fines/heavy oil accumulation. To maintain well productivity, frequent solvent treatments are reburied.

As a result of the polymer injection, the WOR has been reduced 65% while oil production has increased about 50%. Although polymer breakthrough has occurred in most of the producers after three years of polymer injection, the WOR behavior indicates the polymer is performing as intended. Injectant costs in 1986 were about 34 cents per barrel of water injected.

SIGNIFICANCE OF PROJECT

The initial slug design was modified to improve injectivity based on a field injectivity test. Even so, injectivity reductions of up to 70% have been experienced in the project.

CHEMICAL PROJECT--FIELD DATA SUMMARY

Project Name: Storms Pool
Location: White County, Illinois
Operator: Energy Resources
Reservoir: Waltersburg

Project Description
- Size of Project: Pilot (100 acres)
- Chemical Process: Polymer-Mobility Control
- Process Design: 0.23 PV of biopolymer slug

Reservoir Depletion at Start: Mature Waterflood
Date of First Injection: 10/01/80
Date of Latest Data: 06/01/82

RESERVOIR PARAMETERS--NPC SCREENING CRITERIA

Parameter	NPC CRITERIA Surfactant	Polymer	Alkaline	Project Data
Depth, feet	--	--	--	2,300
Reservoir Temperature, °F	200	200	200	95
Permeability, millidarcy	40	20	20	--
Oil Gravity, °API	--	--	30	35
Oil Viscosity, centipoise	40	100	90	6
Salinity of Formation Brine, TDS	100,000	100,000	100,000	--
Rock Type	SS	SS/CARB	SS	SS

CONSTRAINTS ON EOR RECOVERY

(Listed in order of decreasing significance)

1. Description: A mobility control, biopolymer flood was inappropriate for reservoir conditions.
   Classification: Process Design
   Limitation: Management

2. Description: Mobility control lost due to bacterial degradation of biopolymer.
   Classification: Mobility Control
   Limitation: Technology

STORMS POOL IMPROVED WATERFLOOD PROJECT
WHITE COUNTY, ILLINOIS

DISCUSSION

The Storms Pool improved waterflood project was designed to evaluate the efficiency of polymer flooding in a reservoir which had been extensively waterflooded. The project was conducted in a 100-acre project in the Waltersburg sandstone of the Storms Pool Field, located in White County, Illinois. This field is typical of many old oil fields in the Illinois Basin. A total of 703,000 barrels of biopolymer-thickened water was injected, which represents about 23% of the pore volume. The project resulted in little or no incremental oil production. The project was terminated early, as expenses were greatly exceeding revenues.

Low production response in the project was attributed to inadequate moveable oil in the pilot area. Fieldwide primary and secondary recovery had been 43% of the original-oil-in-place with even higher recovery in the pilot area. Channeling had been minor during the waterflood. Theoretical and actual waterflood recovery with a moderately stratified reservoir (permeability variation=0.7) and a favorable mobility ratio (M=0.66) provided little potential for improvement with a mobility control polymer flood. Monitoring data also indicated that the polymer was degraded by bacterial activity. With only a small amount of target oil and degradation of the polymer bank pushing the small amount of moveable oil, minimal production response was not surprising.

SIGNIFICANCE OF PROJECT

Inappropriate process selection was the major cause of the negligible production response observed in the Storms Pool improved waterflood project.

CHEMICAL PROJECT--FIELD DATA SUMMARY

Project Name: Big Horn Basin
Location: Wyoming
Operator: Marathon
Reservoir: Various

Project Description
Size of Project: Pilot (Nine well field tests)
Chemical Process: Crosslinked Polymers
Process Design: Fracture conformance treatments; Cr(III) crosslinking of polyacrylamide or hydrolyzed polyacrylamide.

Reservoir Depletion at Start: Mature Secondary
Date of First Injection: 01/01/85
Date of Latest Data: 01/01/88

RESERVOIR PARAMETERS--NPC SCREENING CRITERIA

Parameter	NPC CRITERIA Surfactant	Polymer	Alkaline	Project Data
Depth, feet	--	--	--	
Reservoir Temperature, °F	200	200	200	
Permeability, millidarcy	40	20	20	
Oil Gravity, °API	--	--	30	
Oil Viscosity, centipoise	40	100	90	
Salinity of Formation Brine, TDS	100,000	100,000	100,000	
Rock Type	SS	SS/CARB	SS	SS

Comments on Reservoir Parameters:

All field test wells exhibited adverse waterflood or polymer performance--early breakthrough, channeling, etc.

CONSTRAINTS ON EOR RECOVERY
(Listed in order of decreasing significance)

No constraint.

BIG HORN BASIN PROJECT WYOMING

DISCUSSION

A patented Cr(III) crosslinked polymer process developed by Marathon was evaluated in seven injection wells and two production wells where fracture conformance problems were evident. Claimed advantages of the patented system were: (a) use of a low cost, nontoxic Cr(III) crosslinking agent rather than the highly toxic Cr(VI), (b) tolerance to H_2S and reservoir brines, (c) highly controllable gel times, and (d) flexibility in viscosity range. The field test wells included both sandstone and carbonate reservoirs. Four of seven injection well treatments were considered successful. Increased injection pressures were observed in all treatments but increased projection in offset wells was not observed in three of the wells. One of the successful treatments was in a well where a previous crosslinking treatment with Cr(VI) had failed, due to hydrogen sulfide effects. Both production well treatments caused significant reductions in produced water volumes (cost), as well as major increases in oil projection.

SIGNIFICANCE OF PROJECT

Although not all fracture conformance improvement treatment were successful, average cost for the incremental oil production was quite attractive.

CHEMICAL PROJECT--FIELD DATA SUMMARY

Project Name: Nelson Unit   Operator: Arco
Location: Campbell County, Wyoming   Reservoir: Minnelusa
Project Description
Size of Project: Pilot (Single Injection Well)
Chemical Process: Crosslinked Polymers
Process Design: Four-stage procedure to selectively emplace proprietary, high temperature gelant.

Reservoir Depletion at Start: Mature Secondary
Date of First Injection: 03/01/84   Date of Latest Data: 11/01/84

RESERVOIR PARAMETERS--NPC SCREENING CRITERIA

Parameter	NPC CRITERIA Surfactant	Polymer	Alkaline	Project Data
Depth, feet	--	--	--	8,700
Reservoir Temperature, °F	200	200	200	197
Permeability, millidarcy	40	20	20	90
Oil Gravity, °API	--	--	30	21
Oil Viscosity, centipoise	40	100	90	12
Salinity of Formation Brine, TDS	100,000	100,000	100,000	50,400
Rock Type	SS	SS/CARB	SS	SS

Comments on Reservoir Parameters:

Total dissolved solids concentration of injection brine was 10,800 mg/1.

CONSTRAINTS ON EOR RECOVERY
(Listed in order of decreasing significance)

1. Description: Portion of interval to which an attempt was made to divert fluids subsequentially discovered to be inadequately perforated.
   Classification: Downhole Completion
   Limitation: Management

NELSON UNIT
CAMPBELL COUNTY, WYOMING

DISCUSSION

In the Nelson Minnelusa waterflood unit, the productive "B" Sand is separated from the underlying, wet "C" Sand by a thin dolomite section. Fluid communication through the thin section separating the zones was evident. Profile surveys indicated that 80% of injection was entering the bottom six feet of the perforated interval. Water was cycling through the wet "C" sand. A four-step procedure was used to emplace the proprietary gelant. Step 1 consisted of preflushing the wellbore and tubing with retardant to prevent premature gelation. The main gelant slug with a 48-hour set time was then injected over a 45-hour period. Step 3 consisted of injecting a near wellbore gelant with a two-hour set time. As a last precaution, the tubing was flushed with retardant to displace the gel solution into the formation. Injection at low rates was started after a nine-day shut-in period. Post-treatment injectivity and injection profiles indicated the treatment had plugged off the main water zone. At this time, it was also discovered that the inability of the upper interval to take injected fluids was related to inadequate perforations--not reservoir characteristics. Despite this major surprise, oil production in offset wells increased about 15 barrels of oil per day and water production decreased. Long-term stability of the gelant was established in laboratory tests. The gelant maintained its properties after 340 days at 197°F. Identical tests with Cr(III) crosslinked polyacrylamide and biopolymers indicated at 70% loss in gel strength.

SIGNIFICANCE OF PROJECT

Long-term thermal stability tests of the proprietary gelant system indicate that the initial effectiveness of the gel treatment in the injection well should be sustained for a long period of time.

CHEMICAL PROJECT--FIELD DATA SUMMARY

Project Name: Sho-Vel-Tum Area
Location: Oklahoma
Operator: Mobil
Reservoir: Various

Project Description
- Size of Project: Field (Seven waterflood projects, 205 treatments)
- Chemical Process: Crosslinked Polymers
- Process Design: Chromium-complexed polysaccharide polymer.

Reservoir Depletion at Start: Mature Secondary
Date of First Injection: 01/01/81
Date of Latest Data: 01/01/84

RESERVOIR PARAMETERS--NPC SCREENING CRITERIA

Parameter	NPC CRITERIA Surfactant	Polymer	Alkaline	Project Data
Depth, feet	--	--	--	
Reservoir Temperature, °F	200	200	200	
Permeability, millidarcy	40	20	20	
Oil Gravity, °API	--	--	30	
Oil Viscosity, centipoise	40	100	90	
Salinity of Formation Brine, TDS	100,000	100,000	100,000	
Rock Type	SS	SS/CARB	SS	SS

Comments on Reservoir Parameters:

Production in all cases from multizoned reservoir. Waterflooding plagued by permeability stratification and varying degrees of mobility imbalance.

CONSTRAINTS ON EOR RECOVERY
(Listed in order of decreasing significance)

No constraint.

SHO-VEL-TUM
SOUTHERN OKLAHOMA

DISCUSSION

Chromium-complexed, polysaccharide gel treatment have been applied on a large scale in the Sho-Vel-Tum area in southwestern Oklahoma. Over 200 treatments (as of 1/1/84) were performed in seven fields. Significant injection well profile improvements were reported in each of the seven fields. Economic production response was observed in six of the seven fields. Causes of the lack of response in the one field were not identified. The unit operations in which the treatments were performed were all large-scale waterfloods which had experienced water production problems. Typically, production was from several intervals exhibiting a high degree of permeability stratification. Oil viscosities ranging 4 to 50 centipoise complicated mobility control during the waterfloods.

SIGNIFICANCE OF PROJECT

Crosslinked biopolymer treatments were applied on a large scale to increase recovery in complex, multizone waterfloods.

CHEMICAL PROJECT--FIELD DATA SUMMARY

Project Name: Isenhour Unit
Location: Sublette County, Wyoming
Operator: Belco Petroleum
Reservoir: Almy Sand

Project Description
Size of Project: Field (Twelve wells, 173 acres)
Chemical Process: Alkaline-Polymer
Process Design: KC1 presoak; 4.3% PV cationic polymer to reduce clay swelling; a 37% PV anionic polymer-soda ash blend; followed by drive injection of anionic polymer solution.

Reservoir Depletion at Start: Intermediate Primary
Date of First Injection: 01/01/81
Date of Latest Data: 01/01/85

RESERVOIR PARAMETERS--NPC SCREENING CRITERIA

Parameter	NPC CRITERIA Surfactant	Polymer	Alkaline	Project Data
Depth, feet	--	--	--	3,700
Reservoir Temperature, °F	200	200	200	95
Permeability, millidarcy	40	20	20	21
Oil Gravity, °API	--	--	30	43
Oil Viscosity, centipoise	40	100	90	2.8
Salinity of Formation Brine, TDS	100,000	100,000	100,000	--
Rock Type	SS	SS/CARB	SS	SS

Comments on Reservoir Parameters:

Sandstone contains abundant quantities of water-sensitive clays.

CONSTRAINTS ON EOR RECOVERY
(Listed in order of decreasing significance)

1. Description: 80% of injection volume in one well; minimal or no injection in other wells.
   Classification: Reservoir Heterogeneity
   Limitation: Technology

2. Description: Formation-parting observed; channeling from natural or induced fractures.
   Classification: Injection Control
   Limitation: Management and Technology

3. Description: Inadequate data collection/analysis to identify cause of low injectivity/channeling.
   Classification: Operations-Monitoring

ISENHOUR UNIT
SUBLETTE COUNTY, WYOMING

DISCUSSION

The complex diagenetic environment of the Almy Sand necessitated that clay/fines control techniques be used in conjunction with the alkaline-polymer process. Clay control techniques used in the project evolved from ten years of experience in area waterfloods which had similar clay control problems. The process design included a KC1 presoak, a 4.3% pore volume cationic polymer slug to coat the near wellbore region and control clay swelling, 37% pore volume anionic polyacrylamide-soda ash slug, followed by drive injection with anionic polymer solution. Soda ash was selected as the alkaline agent based on supply/handling considerations. After four years of operation and about 0.5 pore volume of injection, project recovery is estimated at 46% of the original-oil-in-place. Incremental recovery over what would have been recovered with a waterflood an only be speculated.

Low injectivity and reservoir heterogeneity were predominant. One injector injected over 80% of total injection. Since marginal or no injectivity was experienced in the other injectors, either reservoir heterogeneities or inadequate clay control is suspected. With the low injectivity, some formation-parting was observed. In other instances, channels were noted but the cause--heterogeneity or formation-parting--was not identified. Since reported monitoring data on polymer quality was sketchy, injectant quality may have been involved in the injectivity problems. Ultimate volumetric sweep will be poor with the observed flow behavior.

SIGNIFICANCE OF PROJECT

The channeling/injectivity problems experienced in the Isenhour Unit resulted in poor injection control. Apparently, the clay control treatments were unsuccessful.

CHEMICAL PROJECT--FIELD DATA SUMMARY

Project Name: Wilmington Field | Operator: THUMS
Location: California | Reservoir: Ranger Zone

Project Description
Size of Project: Pilot (93 acres - eight injectors, 11 producers)
Chemical Process: Alkaline
Process Design: 10% PV preflush, 67% PV of 0.4% sodium orthosilicate, softened postflush.

Reservoir Depletion at Start: Mature Secondary
Date of First Injection: 01/01/79 | Date of Latest Data: 01/01/86

RESERVOIR PARAMETERS--NPC SCREENING CRITERIA

Parameter	NPC CRITERIA Surfactant	Polymer	Alkaline	Project Data
Depth, feet	--	--	--	2,500
Reservoir Temperature, °F	200	200	200	125
Permeability, millidarcy	40	20	20	131-321
Oil Gravity, °API	--	--	30	15-28
Oil Viscosity, centipoise	40	100	90	23
Salinity of Formation Brine, TDS	100,000	100,000	100,000	21,100
Rock Type	SS	SS/CARB	SS	SS

Comments on Reservoir Parameters:

Low waterflood recovery due to unfavorable mobility ratio and high stratification.

CONSTRAINTS ON EOR RECOVERY
(Listed in order of decreasing significance)

1. Description: Long-term rock consumption, interaction with high hardness formation brine.
   Classification: Chemical Consumption
   Limitation: Technology

2. Description: Downhole scale plugging in procedures.
   Classification: Operations-Scale
   Limitation: Technology

3. Description: Failure to include polymer for mobility control; overlooked potential high alkaline consumption evident in preinjection testing.
   Classification: Process Design
   Limitation: Management

RANGER ZONE ALKALINE PILOT
WILMINGTON FIELD, CALIFORNIA

DISCUSSION

The Ranger Zone in the Wilmington Field is an unconsolidated, highly stratified reservoir. Oil gravity ranges from 15° to 28° API with an average viscosity of 23 centipoise. Waterflood recovery was extremely low due to unfavorable mobility ratio and extreme permeability variations. The final process design was to inject a 10 percent PV slug of softened fresh water to which 1 percent salt had been added, a 67 percent PV slug of 0.4 percent sodium orthosilicate, followed by a softened postflush. The preflush, alkaline slug, and postflush respectively started in January 1979, March 1980, and December 1983. Although water production was reduced in some wells, minimal oil recovery was observed.

Postproject analysis indicated that alkaline consumption was the predominant cause of failure. Long-term rock consumption and interaction with the high hardness formation brine both contributed to high alkaline consumption. Fluid monitoring indicated that the preflush had not effectively displaced the original formation brine. Danger signals concerning alkaline consumption were evident in preinjection laboratory results. Severe scaling was also observed at the producers. Both calcium carbonate and silicate scales were evident. Scaling problems were aggravated by the relative ineffectiveness of the preflush.

SIGNIFICANCE OF PROJECT

High alkaline consumption was the predominant factor responsible for the extremely low oil recovery in the Ranger Zone pilot project.

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RESEARCH NEEDS TO MAXIMIZE ECONOMIC PRODUCIBILITY OF THE DOMESTIC OIL RESOURCE

PART II
EOR FIELD CASE HISTORIES

APPENDIX B
GAS INJECTION

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GAS INJECTION--FIELD PROJECT DATA SUMMARY

Project Name:	Anschutz Ranch East Unit	Operator:	Amoco
Location:	Utah and Wyoming	Reservoir:	Nugget Sand

Project Description
- Size of Project: Field (Eight injectors, 24 producers)
- Injected Gas: Nitrogen
- Type of Process: Miscible Displacement
- Process Design: Injection sequence consisting of buffer gas (natural gas and N_2) followed by nitrogen.

Reservoir Depletion at Start: Early Primary
Date of First Injection: 12/01/82 Date of Latest Data: 06/01/85

RESERVOIR PARAMETERS

Parameter	Value	Comments
Depth, feet	12,800	
Reservoir Temperature, °F	--	
Permeability, millidarcy	3	
Oil Gravity, °API	--	
Reservoir Pressure, psia	5,080	
Minimum Miscibility Pressure, psia	5,080	
Oil Viscosity, centipoise	--	

Comments on Reservoir Parameters:

CONSTRAINTS ON EOR RECOVERY
(Listed in order of decreasing significance)

1. Description: Highly varied sweep efficiency due to extreme anisotropy.
   Classification: Reservoir Heterogeneity
   Limitation: Technology

ANSCHUTZ RANCH EAST UNIT
UTAH AND WYOMING

DISCUSSION

The Nugget Sand in the Anschutz Ranch East unit is a gas condensate reservoir. PVT analyses performed soon after discovery revealed that a significant portion of liquid dropout would occur in the reservoir unless pressure maintenance was started. The reservoir pressure needed to be maintained above the measured dewpoint pressure of about 5100 psig. The pressure maintenance scheme which was selected after detailed phase behavior analysis consisted of a 10% HCPV slug of 35% nitrogen/65% natural gas followed by nitrogen drive gas. The hydrocarbon buffer slug was necessary to promote miscibility and to prevent dewpoint elevation.

The Nugget Sand is an eolian sand dune with a large amount of crossbedding. The depositional environment created an extreme degree of reservoir anisotropy. In addition to vertical permeability variations, lateral variations create a "brick" effect where rock volumes of varying permeability are jumbled together. Conventional permeability layering and correlation do not sufficiently describe the heterogeneity. The reservoir also contains natural fractures--some of high conductivity and some of low conductivity. An inverted 9-spot pattern was selected because of the ease with which it could be converted to other patterns if dictated by gas flow trends and because of the high producer to injector ratio.

Despite the degree of heterogeneity, the reservoir was roughly zoned into three zones. Initially, the injectors were opened in Zone 1 and Zone 2 while the producers were opened in Zone 2 and Zone 3. When initial process monitoring indicated that minimal production was being realized from Zone 3, it was opened in the injectors. Sweep efficiencies from 50% to 70% are being forecast in the extremely heterogeneous reservoir.

SIGNIFICANCE OF PROJECT

Extensive effort was required to design an effective miscible gas flood in a gas condensate reservoir with severe reservoir anisotropy. Reservoir description and phase behavior work were essential to project design.

GAS INJECTION--FIELD PROJECT DATA SUMMARY

Project Name: Bay St. Elaine Field — Operator: Texaco
Location: Terrebonne Parish, LA — Reservoir: 8,000-Foot Sand

Project Description
- Size of Project: Field
- Injected Gas: Carbon Dioxide
- Type of Process: Gravity Stable, Miscible Slug
- Process Design: Miscible slug displaced downdip by nitrogen drive gas.
- Reservoir Depletion at Start: Mature Primary
- Date of First Injection: 01/20/81 — Date of Latest Data: 09/01/81

RESERVOIR PARAMETERS

Parameter	Value	Comments
Depth, feet	7,400	
Reservoir Temperature, °F	164	
Permeability, millidarcy	1,480	
Oil Gravity, °API	36	
Reservoir Pressure, psia	3,334	
Minimum Miscibility Pressure, psia	3.330	
Oil Viscosity, centipoise	0.7	

Comments on Reservoir Parameters:

CONSTRAINTS ON EOR RECOVERY
(Listed in order of decreasing significance)

1. Description: Downhole corrosion damage in producers.
   Classification: Operations - Corrosion
   Limitation: Technology

2. Description: Submersible pumps are prone to lift problems with varying lift conditions when gas breakthrough occurs.
   Classification: Operations - Artificial Lift
   Limitation: Technology

BAY ST.ELAINE FIELD
TERREBONNE PARISH, LOUISIANA

DISCUSSION

The 8,000-foot Reservoir "E" Sand unit in which the gravity stable, carbon dioxide displacement process is being conducted was nearing depletion via a strong waterdrive when the project was started. The steeply dipping reservoir (36°) is fault bounded and well defined. Initial process design efforts focused on defining the velocities at which displacement would be gravity stable, i.e. the velocities below which viscous fingering would not adversely affect displacement. The critical velocities for each of the displacement processes involved--oil bank displacing water, carbon dioxide displacing oil, and nitrogen drive gas displacing the carbon dioxide--were separately defined. To allow reasonable injection rates (i.e.,project life), it was determined that methane would have to be added to the carbon dioxide gas to increase the density difference and allow higher injection rates. Eleven percent methane was required to achieve the desired density difference. To counteract the increased minimum miscibility pressure as a result of the methane, 5% n-butane was added to the carbon dioxide-methane injection gas. Injection of a 33% pore volume slug of this gas mixture was begun in early 1981. Upon completion of the carbon dioxide-methane slug injection, plans are to inject nitrogen drive gas for an 18-month period.

Since residual oil saturation estimates via volumetric/material balance methods varied from 10% to 40%, several techniques were used to more accurately define the current oil saturation. These techniques included pressure coring, conventional openhole logging, sidewall core analysis, and single well partitioning tracer test. Although the results from these different techniques were unavailable, their use illustrates the importance of accurately defining the oil saturation. Pressure pulse tests were also used to confirm reservoir communication. Significantly, the pulse tests identified a previously undetected fault which isolated portions of the reservoir from injection. The final project consisted of a single injection well and two producers.

SIGNIFICANCE OF PROJECT

The composition of the injection gas in the Bay St. Elaine Project resulted from tailoring the carbon dioxide miscible process to specific reservoir conditions. Pressure pulse monitoring refined the fault structure model.

GAS INJECTION--FIELD PROJECT DATA SUMMARY

Project Name: Camurlu Field
Location: Turkey
Operator: Turkish Petroleum
Reservoir: Alt Sinan

Project Description
- Size of Project: Pilot (Two wells)
- Injected Gas: Carbon Dioxide
- Type of Process: Cyclic Stimulation
- Process Design: 10 MMSCF CO_2 slug; 10 day soak; produce until uneconomic; restimulate[2].

Reservoir Depletion at Start: Mature Primary
Date of First Injection: 10/01/84
Date of Latest Data: 01/01/86

RESERVOIR PARAMETERS

Parameter	Value	Comments
Depth, feet	2,600	
Reservoir Temperature, °F	160	
Permeability, millidarcy	5	
Oil Gravity, °API	12	
Reservoir Pressure, psia	1,800	
Minimum Miscibility Pressure, psia	NA	
Oil Viscosity, centipoise	284	

Comments on Reservoir Parameters:

CONSTRAINTS ON EOR RECOVERY
(Listed in order of decreasing significance)

1. Description: CO_2 injectivity significantly lower than preproject estimate.
   Classification: Reduced Injectivity
   Limitation: Technology

2. Description: Hydrate plugging in surface lines.
   Classification: Injectant Quality
   Limitation: Management

CAMURLU FIELD
TURKEY

DISCUSSION

This carbon dioxide cyclic stimulation pilot is evaluating the economic feasibility of using a locally available source of pressured carbon dioxide to stimulate production of a low gravity, viscous oil. The low cost injection gas is produced from an underlying reservoir at a wellhead pressure of approximately 1450 psig. Since the gas contains 73% carbon dioxide and achieving miscibility is not a concern, the produced gas is injected without compression or further processing. Except for anticipated surface hydrate problems, minimal problems have been experienced with the low cost CO_2 source.

Carbon dioxide stimulation treatments are being performed in two wells. Up to three cycles have been conducted. Intended plans were to inject 10 MMSCF of gas, soak for 10-12 days, and then produce until production declined to an extent that restimulation was required. Response results to date have been inconclusive due to the extremely low carbon dioxide injectivity experienced--up to two or three months to inject a 10 MMSCF slug. Plugging with solids has been ruled out since fuel oil injectivity before and after carbon dioxide injection is unchanged. Laboratory tests indicate minimal potential for asphaltene deposition. Suspected cause of the low injectivity is the co-injection of liquids in the unprocessed gas.

SIGNIFICANCE OF PROJECT

Providing carbon dioxide injectivity problems can be resolved, the low cost carbon dioxide injectant should allow economical stimulation operations to be conducted in this heavy oil reservoir.

GAS INJECTION--FIELD PROJECT DATA SUMMARY

Project Name: Dollarhide Devonian Unit — Operator: Unocal
Location: Andrews County, Texas — Reservoir: Devonian

Project Description

Size of Project:	Field (To be implemented in four phases)
Injected Gas:	Carbon Dioxide
Type of Process:	Miscible Displacement
Process Design:	Inject 25% HCPV CO_2 slug followed by drive water to depletion.

Reservoir Depletion at Start: Mature Secondary
Date of First Injection: 05/01/85 — Date of Latest Data: 08/01/87

RESERVOIR PARAMETERS

Parameter	Value	Comments
Depth, feet	7,800	
Reservoir Temperature, °F	120	
Permeability, millidarcy	9	
Oil Gravity, °API	40	
Reservoir Pressure, psia	3,200	
Minimum Miscibility Pressure, psia	1,600	
Oil Viscosity, centipoise	0.4	

Comments on Reservoir Parameters:

CONSTRAINTS ON EOR RECOVERY
(Listed in order of decreasing significance)

No constraint.

DOLLARHIDE DEVONIAN UNIT
ANDREWS COUNTY, TEXAS

DISCUSSION

The Devonian reservoir in the Dollarhide unit exhibited excellent secondary recovery. An observed secondary to primary ratio of about 2:1 and an injection/withdrawal ratio near 1.0 during secondary operations are indicative of favorable reservoir continuity and uniformity. Because heterogeneity was not a major concern and achieving miscibility was not a question with current reservoir about 2000 psig over the minimum miscibility pressure (MMP), Unocal elected to forego the time delay inherent with a pilot. A fieldwide project to be implemented in four phases was planned. A phased carbon dioxide project reduces CO_2 purchase requirements for the later phases since more recycled CO_2 is available from the early phases can guide operations for the later phases. A unique decision faced by Unocal was whether to allow reservoir pressure to decrease from 3800 psia to the MMP of 1600 psig where lower volumes of CO_2 would be required or to continue operations at the higher pressure. The decision to operate at higher pressures was based on: (1) not losing current production with the pressure drop, and (2) having greater flexibility for recycling CO_2 without separation. Injection of a 25% HCPV slug was planned with WAG injection only if required to control channeling.

Carbon dioxide injection was started in the Phase I area in May 1983. Initially, trucked-in CO_2 was injected in only four wells. Pipeline CO_2 injection began in January 1986. Through August 1987, about 6% of a HCPV of carbon dioxide has been injected in the Phase I area at rates equivalent to prior water injection rates. Individual pattern injection volumes ranged from 2% to 8% HCPV. Carbon dioxide breakthrough did not occur at any producer until after 20 months of full scale injection. The only well exhibiting significant CO_2 breakthrough, correspondingly, has experienced a 50% increase in oil production. Profile surveys in the injection wells indicate injectant distribution similar to that experienced during water flooding. From all indications, a highly efficient displacement is occurring. Additional simulation work has led to a slight modification in injection plans to achieve even higher recovery. Current plans are to inject a 10% HCPV CO_2 slug to realize accelerated response and then switch to a 21% HCPV CO_2 slug using a 1:1 WAG operation. By switching to a WAG operation, increased recovery is anticipated from improved mobility control. Stepwise implementation of CO_2 injection throughout the unit should be completed by the mid-1990s.

SIGNIFICANCE OF PROJECT

The minimal carbon dioxide breakthrough experienced in the Dollarhide unit establishes that mobility control can be achieved with CO_2 slug injection, rather than WAG injection if the reservoir is relatively uniform.

GAS INJECTION--FIELD PROJECT DATA SUMMARY

Project Name: Ford Geraldine Unit — Operator: Conoco
Location: Andrews County, Texas — Reservoir: Delaware Sand
Project Description
Size of Project: Field (Phase I and Phase II)
Injected Gas: Carbon Dioxide
Type of Process: Miscible Displacement
Process Design: Inject 30% HCPV CO_2 slug followed by drive water injection.
Reservoir Depletion at Start: Mature Secondary
Date of First Injection: 02/01/81 — Date of Latest Data: 01/01/88

RESERVOIR PARAMETERS

Parameter	Value	Comments
Depth, feet	2,680	
Reservoir Temperature, °F	83	
Permeability, millidarcy	64	
Oil Gravity, °API	40	
Reservoir Pressure, psia	1,300	
Minimum Miscibility Pressure, psia	1,000	
Oil Viscosity, centipoise	1.4	

Comments on Reservoir Parameters:

CONSTRAINTS ON EOR RECOVERY

(Listed in order of decreasing significance)

1. Description: Low CO_2 injectivity contributing to pattern imbalance and formation pressure parting.
   Classification: Low Injectivity
   Limitation: Technology

2. Description: Highly variable CO_2 injectivity indicative of reservoir heterogeneity.
   Classification: Reservoir Heterogeneity
   Limitation: Technology

3. Description: Known excursions above formation parting pressure.
   Classification: Injection Control
   Limitation: Management

FORD GERALDINE UNIT
WEST TEXAS

DISCUSSION

Promising performance in the Delaware Sand reservoir in the Two Freds CO_2 project led Conoco to start a phased, carbon dioxide miscible flood project in the Ford Geraldine unit in 1981. During the first four years of CO_2 injection, rates were erratic due to inadequate supply. Carbon dioxide has been injected at a stable, 20 MMSCFD rate since late 1985 when reliable CO_2 supply arrangements were made. Maintaining pattern injection balance has been difficult since several injectors exhibit low injection rates at the 1200 psi injection wellhead pressure limit imposed by parting pressure considerations. Although short-term excursions above parting pressure have occurred, carbon dioxide breakthrough, in early life has been minimal. Of the three wells experiencing significant CO_2 breakthrough, the cause of the breakthrough can be attributed to factors other than pressure parting. The produced CO_2 to oil ratio after 3 years of full scale injection (10 to 15% PV CO_2) is 3.5 MCF per barrel. The produced gas which is recycled without separation contains 84% CO_2 and exhibits the same minimum miscibility pressure as CO_2 due to the 7% heavier hydrocarbons in the stream. Unit production has more than doubled since the start of CO_2 injection. Recovery estimates are premature in this early life project.

SIGNIFICANCE OF PROJECT

The Ford Geraldine unit project represents a commercial scale, miscible CO_2 project implemented without the intensive engineering/pilot tests efforts typical of many projects. In the early stages, results appear promising.

GAS INJECTION--FIELD PROJECT DATA SUMMARY

Project Name: Garber Field — Operator: Arco
Location: Garfield County, Oklahoma — Reservoir: Crews Sand

Project Description
- Size of Project: Field (Four injectors, nine producers)
- Injected Gas: Carbon Dioxide
- Type of Process: Miscible Displacement
- Process Design: Inject 30% HCPV CO_2 slug; drive water to depletion; peripheral water injection to contain CO_2 in project area.
- Reservoir Depletion at Start: Mature Secondary
- Date of First Injection: 10/20/81 — Date of Latest Data: 01/01/84

RESERVOIR PARAMETERS

Parameter	Value	Comments
Depth, feet	1,950	
Reservoir Temperature, °F	95	
Permeability, millidarcy	57	
Oil Gravity, °API	47	
Reservoir Pressure, psia	1,250	
Minimum Miscibility Pressure, psia	1,075	
Oil Viscosity, centipoise	2.1	

Comments on Reservoir Parameters:

CONSTRAINTS ON EOR RECOVERY
(Listed in order of decreasing significance)

1. Description: Gas channeling, directional flow evident; WAG injection may have reduced severity.
   Classification: Reservoir Heterogeneity
   Limitation: Technology and Management

GARBER FIELD
GARFIELD COUNTY, OKLAHOMA

DISCUSSION

The Pennsylvanian Age, Crews sandstone within the specific project area is a deltaic lobe within a deltaic environment. Extensive drilling to implement the project (19 new wells) identified significant heterogeneities. Waterflooding had been very successful despite these heterogeneities. The central portion of the project consisted of water injection to repressure the reservoir from 220 psig to the desired pressure of 1200 psig or greater. Tracer breakthrough times during the water repressuring phase indicated major reservoir heterogeneities existed. When carbon dioxide injection was started in 1981, gas phase tracers were injected two weeks after initial CO_2 injection. As with the water injection phase, major heterogeneities were apparent. Excessive CO_2 breakthrough in one producer necessitated shutting in the well to control CO_2 usage. Despite these apparent heterogeneities, the CO_2 production on a total project bases did not exceed 5 MCF per barrel through the CO_2 injection phase. Oil recovery during the early stages of drive water injection was already 11% of the original-oil-in-place. No injectivity reductions were apparent when injection was switched from CO_2 to drive water.

SIGNIFICANCE OF PROJECT

Although an effective miscible gas flood was performed in a reservoir with known heterogeneities without resorting to WAG operations, WAG injection in selected wells may have reduced gas channeling problems.

GAS INJECTION--FIELD PROJECT DATA SUMMARY

Project Name: Hawkins Field Unit
Operator: Exxon
Location: East Texas
Reservoir: Woodbine Dexter

Project Description

- Size of Project: Field
- Injected Gas: Flue Gas
- Type of Process: Gravity Stable, Immiscible Displacement
- Process Design: Flue gas-hydrocarbon gas injection at gas-oil contact to displace oil column.
- Reservoir Depletion at Start: Mature Primary
- Date of First Injection: 03/01/77
- Date of Latest Data: 01/01/88

RESERVOIR PARAMETERS

Parameter	Value	Comments
Depth, feet	4,600	
Reservoir Temperature, °F	168	
Permeability, millidarcy	3,400	
Oil Gravity, °API	24	
Reservoir Pressure, psia	1,600	
Minimum Miscibility Pressure, psia	NA	
Oil Viscosity, centipoise	3.7	

Comments on Reservoir Parameters:

CONSTRAINTS ON EOR RECOVERY

(Listed in order of decreasing significance)

1. Description: Accelerated corrosion in flue gas injection system.
   Classification: Operations-Corrosion
   Limitation: Technology

HAWKINS FIELD UNIT
EAST TEXAS

DISCUSSION

The reservoirs in the Hawkins field, the Upper Lewisville and Lower Dexter, are extensively faulted. Fault blocks are communicating with the exception of a large fault which divides the field into two productive areas--an East and West Fault Block. An underlying asphalt layer controls the amount of pressure support received from the underlying Woodbine aquifer. In the East Fault Block where the asphalt layer is not present, the reservoir is produced by a strong water drive from the data of initial production. In the West Fault Block where the asphalt layer varies in thickness, the degree of water drive support varied with the thickness of the asphalt layer. As a result, a tilted oil-water contact developed during primary production. As the oil-water contact tilted, the oil column began invading the gascap on one edge of the fault block. The gas injection project at Hawkins was begun to stop further movement of the oil-water contact and to produce the remaining oil column by moving the gas-oil contact down to the water contact. Recovery efficiency with this immiscible, gravity stable, gas displacement process was estimated at 80% versus 60% via water drive of the oil column.

Flue gas injection was started in the second quarter of 1977 when 36 converted producers began injecting flue gas at the gas-oil contact. Produced hydrocarbon gas was re-injected higher on structure. Separate gas injection systems were maintained for the flue and hydrocarbon gas streams. Within one and one half years after initial flue gas injection, sufficient breakthrough had occurred to prevent the gas produced by the oil wells from being used as fuel. A separate fuel gas system using gas wells located at the crest of the gascap was developed. At present, after ten years of operation, about 70 MMSCFD of casinghead gas is re-injected along with 60 MMSCFD of flue gas. Crestal fuel gas requirements are about 25 MMSCFD.

Material balance calculations indicate the gas injection project essentially stopped water influx. As a result, the oil rim is being produced by gas drive. Production logging methods have confirmed that the oil-water contact has not moved and that the gas-oil contact is moving downward as the oil rim is being produced. Displacement calculations considering the reservoir volume displaced by gas and production data indicate the recovery efficiency is about 85% of the oil-in-place in the oil-invaded portion of the gascap.

Pilot operations are being planned to conduct similar gas displacement operations in the water-invaded portions of the oil column. In this area, the water drive residual oil saturation is about 35%, whereas the residual oil saturation after gas driving an oil column through the section is about 12%. As the oil column is driven through the water-invaded portion of the oil column, it will increase the thickness as residual oil is mobilized. Once the oil column has been displaced to the original oil-water contact, injection/production will be balanced so that further movement of the oil-water contact does not occur. Continued gas injection will move the gas-oil contact down to the original oil-water contact as oil is produced from the oil rim.

SIGNIFICANT OF PROJECT

Immiscible gas displacement, as is occurring in the Hawkins field unit, can be very efficient if the displacement is kept gravity stable. In this project, displacement efficiency approaches 85%.

GAS INJECTION--FIELD PROJECT DATA SUMMARY

Project Name: Intisar "D: Field | Operator: Occidental
Location: East Texas | Reservoir: Intisar "D"

Project Description
- Size of Project: Field (Approximately 35 wells)
- Injected Gas: Hydrocarbon
- Type of Process: Gravity Stable, Miscible Displacement
- Process Design: Displace oil column through crestal gas injection; downdip water injection for pressure maintenance.
- Reservoir Depletion at Start: Early Primary
- Date of First Injection: 12/01/69 | Date of Latest Data: 06/01/80

RESERVOIR PARAMETERS

Parameter	Value	Comments
Depth, feet	9,200	
Reservoir Temperature, °F	226	
Permeability, millidarcy	200	
Oil Gravity, °API	--	
Reservoir Pressure, psia	4,000	
Minimum Miscibility Pressure, psia	4,000	
Oil Viscosity, centipoise	0.5	

Comments on Reservoir Parameters:

CONSTRAINTS ON EOR RECOVERY
(Listed in order of decreasing significance)

1. Description: Ultimate recovery is rate sensitive due to gas coning with high vertical permeability.
   Classification: Mobility Control
   Limitation: Technology

2. Description: Updip movement of water-oil contact occurred; lower recovery in this zone than in gas-displaced zone.
   Classification: Injection Control
   Limitation: Management

INTISAR 'D' FIELD
LIBYA

DISCUSSION

Miscible displacement operations were implemented in the Intisar "D" field soon after primary development was completed. About 35 wells are involved in the project. Although downdip displacement of the oil column by crestal gas injection is the primary displacement process, downdip water injection for pressure maintenance has caused some upward movement of the oil-water contact. As a result, recovery in this area has been decreased since displacement of waterflood residual oil saturation by the gas was indicated to be uneconomic in simulation work. Although the reservoir is relative homogeneous, minor oil bypassing has been observed in localized areas of lower reservoir quality. The primary limitation on oil recovery is gas coning with the high deliverability of the producers and high vertical permeabilities. Ultimate recovery is sensitive to individual well producing rates and completion intervals. Workovers to optimize the completion interval relative to the gas-oil contact increased recovery more than drilling additional infill producers. Estimated fieldwide ultimate recovery of nearly 70% of the original-oil-in-place is projected. Continually decreasing residual oil saturations in the gas swept area indicate that the high recoveries are, in part, due to continued vaporization of the oil.

SIGNIFICANCE OF PROJECT

Operations parameters like individual well producing rates, completion intervals, and downdip water injection limited recovery more than reservoir heterogeneities or process displacement efficiency.

GAS INJECTION--FIELD PROJECT DATA SUMMARY

Project Name: Jay-Little Escambia Creek — Operator: Exxon
Location: Alabama/Florida — Reservoir: Smackover/Norphlet

Project Description
- Size of Project: Field (14,000 acres)
- Injected Gas: Nitrogen
- Type of Process: Miscible Displacement
- Process Design: 20% HCPV nitrogen slug with WAG injection over 15-year period followed by 8 years of water injection.
- Reservoir Depletion at Start: Mature Secondary
- Date of First Injection: 12/01/81 — Date of Latest Data: 06/01/83

RESERVOIR PARAMETERS

Parameter	Value	Comments
Depth, feet	15,000	
Reservoir Temperature, °F	285	
Permeability, millidarcy	35	
Oil Gravity, °API	51	
Reservoir Pressure, psia	7,400	
Minimum Miscibility Pressure, psia	3,600	
Oil Viscosity, centipoise	0.2	

Comments on Reservoir Parameters:

CONSTRAINTS ON EOR RECOVERY
(Listed in order of decreasing significance)

1. Description: Water injectivity was reduced nearly 60% with WAG injection.
   Classification: Reduced Injectivity
   Limitation: Technology

2. Description: Poor injection profiles in half of injectors.
   Classification: Reservoir Heterogeneity
   Limitation: Technology

JAY-LITTLE ESCAMBIA CREEK FIELD
ALABAMA AND FLORIDA

DISCUSSION

Production in the Jay-Little Escambia Creek fields unit is from the Smackover carbonate reservoir and the Norphlet Sand. Oil production occurs primarily in the dolomitized section of the Smackover carbonate. Average pay thickness in the unit is 350 feet. Since waterflooding was implemented soon after discovery, the combined primary and secondary recovery was good. Ultimate Primary and secondary recovery without nitrogen injection was estimated at about 50%. During the design stage of the miscible gas injection project, natural gas, carbon dioxide, and nitrogen were considered as an injectant since all were miscible with the reservoir oil. Nitrogen was selected over natural gas on the basis of economics, while carbon dioxide was supply-limited and involved longer lead times to implement the project. Increased corrosion problems were also anticipated if carbon dioxide had been used.

Methane gas injection was started in January 1981, while the nitrogen facilities were being installed. Nitrogen injection began in December 1981 using the WAG process. As of mid-1983, about 1.8% HCPV of nitrogen had been injected at an approximate 3:1 WAG ratio. Plans are to inject a 20% HCPV nitrogen slug over a 15 year period followed by about eight years of water injection. Projected incremental recovery from nitrogen injection is about 6.5% of the original-oil-in-place.

During the initial stages of the project, two primary problems have been experienced: reduced water injectivity during the WAG process and poor injection profiles. On the average, water injectivity was decreased 57% by the WAG operations. The decreased in injectivity was attributed to the high concentrations of trapped nitrogen gas near the injection well. Actual injectivity reductions were more severe than indicated in preproject injectivity testing. Spinner surveys which were conducted in all of the injection wells indicate inadequate injection profiles in nearly half of the injection wells. Evaluation of surveys at different nitrogen injection pressures revealed that profiles were slightly improved at higher pressures. As a result, overall system pressure was increased from 6500 psig to 7000 psig. To minimize distortions in nitrogen flow, higher WAG ratios are used in the injection wells which exhibit the worst profiles. Despite the poor injection profiles, premature nitrogen breakthrough has not been a problem in early life. After two years of nitrogen injection, produced nitrogen volumes were only about 5% of the total gas stream. Flood rates in individual zones are estimated using spinner survey results combined with simulation work. Since the fresh water in the reservoir makes detection of fronts by logging difficult, heavy emphasis is placed upon the simulation model. High confidence is placed in the reservoir description since every well was cored when drilled. Anticipated tertiary recovery represents about 7% of the original-oil-in-place.

SIGNIFICANCE OF PROJECT

Factors other than miscibility influenced the selection of nitrogen as the miscible injectant in this deep, high pressure reservoir.

GAS INJECTION--FIELD PROJECT DATA SUMMARY

Project Name: Lake Barre Project — Operator: Texaco
Location: Terrebonne Parish, Louisiana — Reservoir: R-1 Sand
Project Description
Size of Project: Field (One fault block)
Injected Gas: Nitrogen
Type of Process: Gravity Stable, Immiscible Displacement
Process Design: Nitrogen injection at gas-oil contact to displace oil downdip.
Reservoir Depletion at Start: Mature Primary
Date of First Injection: 08/01/78 — Date of Latest Data: 10/01/81

RESERVOIR PARAMETERS

Parameter	Value	Comments
Depth, feet	17,500	
Reservoir Temperature, °F	280	
Permeability, millidarcy	95	
Oil Gravity, °API	42	
Reservoir Pressure, psia	4,300	
Minimum Miscibility Pressure, psia	5,800	
Oil Viscosity, centipoise	--	

Comments on Reservoir Parameters:

Reservoir dip angle is 26°

CONSTRAINTS ON EOR RECOVERY
(Listed in order of decreasing significance)

No constraint.

LAKE BARRE FIELD
TERREBONNE PARISH, LOUISIANA

DISCUSSION

The R-1 Sand, Segment "G" in the Lake Barre field, is a fault-bounded reservoir. The production drive mechanism has been depletion drive supported by gascap expansion. When hydrocarbon gas injection was started in 1973, reservoir pressure had fallen from about 9000 psig at discovery to about 3400 psig. By 1978 when hydrocarbon gas injection was stopped, reservoir pressure had risen to about 4000 psig at the gas-oil contact. Both nitrogen and carbon dioxide were considered as injection gases. Carbon dioxide was rejected because of supply considerations and its density at reservoir conditions. At reservoir conditions, carbon dioxide would have been heavier than oil, and displacement would have been difficult to control. Nitrogen was 31% heavier than natural gas, but still lighter than the oil. Minimal contamination of the gascap with nitrogen was anticipated due to the large density difference. If contamination does occur, the low BTU gas will be either used in the cryogenic nitrogen plant or reinjected in the reservoir. When the oil column has been produced and the gascap blown down, the intent is to use the high nitrogen content gas in a similar displacement process in adjacent reservoirs. Operations are too early in flood life to evaluate actual versus planned performance.

SIGNIFICANCE OF PROJECT

The injection gas selection process illustrates the different variables which must be considered--in some cases, miscibility is not the controlling factor. The intended use of the nitrogen in other reservoirs when the R-1 Sand is depleted represents effective management of an expensive injectant.

GAS INJECTION--FIELD PROJECT DATA SUMMARY

Project Name: Lick Creek Meakin Sand Unit — Operator: Phillips
Location: Bradley County, Arkansas — Reservoir: Meakin Sand
Project Description
Size of Project: Field (23 injectors, 38 producers)
Injected Gas: Carbon Dioxide
Type of Process: Immiscible Displacement
Process Design: Sequential process - 1 year, cyclic CO_2 stimulation; 2 year, CO_2 slug injection; WAG injection; drive water injection.
Reservoir Depletion at Start: Mature Primary
Date of First Injection: 02/01/76 — Date of Latest Data: 11/01/85

RESERVOIR PARAMETERS

Parameter	Value	Comments
Depth, feet	2,550	
Reservoir Temperature, °F	118	
Permeability, millidarcy	1,200	
Oil Gravity, °API	17	
Reservoir Pressure, psia	1,000	
Minimum Miscibility Pressure, psia	--	
Oil Viscosity, centipoise	160	

Comments on Reservoir Parameters:

CONSTRAINTS ON EOR RECOVERY
(Listed in order of decreasing significance)

1. Description: Severe gas channeling with viscous oil.
   Classification: Mobility Control
   Limitation: Technology

2. Description: Oil treating complicated by trapped CO_2; tubing leaks starting about three years after initial injection.
   Classification: Operations - Oil Treating/Corrosion
   Limitation: Technology

LICK CREEK MEAKIN SAND UNIT
BRADLEY COUNTY, ARKANSAS

DISCUSSION

Primary and secondary recovery in the Lick Creek Meakin Sand unit had been relatively low because of the relatively high viscosity of the 17 degree API oil-160 centipoise at reservoir conditions. Although miscibility could not be achieved with the low gravity oil at the pressure feasible in the 2,500 feet deep reservoir, economic incremental recovery was anticipated from viscosity reduction/crude swelling effects. Processes design for the immiscible carbon dioxide flood included four separate phases.

Phase I which consisted of cyclic stimulation of all of the producers and about 40% of the injectors was started in early 1976. Intent of these treatments was: (1) to contact oil not readily available to the injectors, (2) to increase reservoir pressure so additional viscosity reduction effects could be realized and so wells would flow, and (3) to realize early production response. Although significant production responses were observed in some wells, response was generally short-lived, and subsequent stimulations exhibited minimal response. Rapid carbon dioxide breakthrough occurred in some producers. Wells which did not experience gas breakthrough exhibited a gas drive response similar to the stimulated wells. At the end of this approximate year period, reservoir pressure had not risen to desired 1000 psig level.

When Phase II injection of a carbon dioxide slug was begun in February 1977, reservoir pressure increased to the desired 1000 psig level and the producers began to flow. Although some gas drive response was evident, gas channels developed in several locations within months. As a result, the Phase III WAG injection was implemented sooner than originally planned. The WAG ratio has steadily increased through 1983. Currently, it is approaching the desired 1:1 ratio. As the injected water broke through in the gas channels, gas lifting with carbon dioxide was started to lift the fluids.

Both foams and polymers were evaluated for channeling control. Foams were limited to permeabilities less than 150 darcies, whereas effective permeability of the channels was as high as 3000 darcies. Initial attempts with an anionic crosslinked polymer were unsuccessful; the channel blocks broke down within a few WAG cycles. Later tests with a nonionic polymer which was linked in-situ with an organic crosslinking agent appeared to be effective for about one year. Payout of the polymer treatment occurred in about one and one half months. Tracer tests were used to determine the size of the channels to be blocked; i.e., the required polymer volume.

SIGNIFICANCE OF PROJECT

Crosslinked polymer treatments controlled the severe gas channeling which was observed in this immiscible carbon dioxide waterflood project. This project is the only known immiscible carbon dioxide project carried to completion in a heavy oil reservoir.

GAS INJECTION--FIELD PROJECT DATA SUMMARY

Project Name: Little Knife Field — Operator: Gulf
Location: North Dakota — Reservoir: Mission Canyon
Project Description
Size of Project: Pilot (Nonproducing minitest; 5-arce, inverted 4-spot pattern)
Injected Gas: Carbon Dioxide
Type of Process: Miscible Displacement
Process Design: Inject 25% HCPV CO_2 slug at about 1:1 WAG ratio in five equal slugs; follow with drive water.
Reservoir Depletion at Start: Intermediate Primary
Date of First Injection: 12/11/80 — Date of Latest Data: 09/17/81

RESERVOIR PARAMETERS

Parameter	Value	Comments
Depth, feet	9,800	
Reservoir Temperature, °F	245	
Permeability, millidarcy	30	
Oil Gravity, °API	41	
Reservoir Pressure, psia	3,600	
Minimum Miscibility Pressure, psia	3,400	
Oil Viscosity, centipoise	0.2	

Comments on Reservoir Parameters:

CONSTRAINTS ON EOR RECOVERY
(Listed in order of decreasing significance)

1. Description: Effects of known heterogeneities on large scale project undefined since process limited to single zone in small area.
   Classification: Process Design
   Limitation: Management

LITTLE KNIFE MINITEST
WILLISTON BASIN, NORTH DAKOTA

DISCUSSION

The nonproducing pilot test conducted by Gulf in the Little Knife field utilized production logging/fluid sampling in observation wells to monitor efficiency of the miscible displacement process. As a result, the project life was less than a year as compared to two to four-years lives in many pilots. Obtaining results quickly was important since continued primary production was rapidly causing reservoir pressure to fall below the minimum miscibility pressure. Simulation analysis extended to a fieldwide bases indicated the incremental recovery above that which would have been feasible with waterflooding was about 8% of the original-oil-in-place.

A 25% HCPV slug of CO_2 was injected in the pilot using an approximate 1:1 WAG ratio. The carbon dioxide was injected in five approximately equal slugs. WAG injection was used because laboratory and simulation work indicated a slight improvement in recovery over carbon dioxide slug injection. The carbon dioxide process was evaluated in one of the more permeable and continuous zones in the Mission Canyon reservoir. Although performance was promising in a small area in a single zone, performance on a large scale in multiple zones can only be surmised. In effect, the pilot project confirmed the displacement efficiency of the precess but did not determine whether known reservoir heterogeneities would allow economic recovery on a commercial scale.

SIGNIFICANCE OF PROJECT

By performing a small scale pilot using observations wells rather producers, efficiency of the carbon dioxide miscible displacement process was determined in one year, rather than the longer periods usually involved in EOR pilots. Offsetting this, the effects of reservoir heterogeneities on a commercial scale project were not defined since injection was limited to a single zone in a small area.

GAS INJECTION--FIELD PROJECT DATA SUMMARY

Project Name:	Maljamar Field	Operator:	Conoco
Location:	Lea County, New Mexico	Reservoir:	Grayburg/San Andres

Project Description
- Size of Project: Pilot (5-arce, inverted 5-spot pattern)
- Injected Gas: Carbon Dioxide
- Type of Process: Miscible Displacement
- Process Design: Inject about 20% PV CO_2, drive water to depletion.
- Reservoir Depletion at Start: Mature Secondary
- Date of First Injection: 05/01/83 Date of Latest Data: 01/01/86

RESERVOIR PARAMETERS

Parameter	Value	Comments
Depth, feet	3,800	
Reservoir Temperature, °F	90	
Permeability, millidarcy	18	
Oil Gravity, °API	37	
Reservoir Pressure, psia	3,100	
Minimum Miscibility Pressure, psia	1,515	
Oil Viscosity, centipoise	0.8	

Comments on Reservoir Parameters:

CONSTRAINTS ON EOR RECOVERY
(Listed in order of decreasing significance)

1. Description: CO_2 migration from intended flood interval in Ninth Massive San Andres.
   Classification: Injection Control
   Limitation: Technology

2. Description: Significant reduction in post-CO_2 brine injectivity.
   Classification: Reduced Injectivity
   Limitation: Technology

MALJAMAR CO_2 PILOT
LEA COUNTY, NEW MEXICO

DISCUSSION

Operations in the Maljamar, miscible CO_2 pilot were divided into five phases. Phase I which began in 1981 consisted of fresh water injection to completely water-out the reservoir and to move water of known salinity past the logging observation wells. After nine months, brine of salinity similar to the original formation brine was injected along with tracers to determine fluid movement patterns in the pilot area. When tracer response was seen in the producers, carbon dioxide injection was started in May 1983. Although CO_2 production was observed with 35 days, CO_2 producing rates at the end of the CO_2 injection period in December 1983 were only 2% of the injection rate. The CO_2 slug volumes in the two zones, the Sixth Grayburg and Ninth Massive Sand Andres, were 20% and 14% pore volume, respectively. Pore volume estimates are based on post-pilot simulation studies. Carbon dioxide injectivity was similar to preflush brine injectivity. Post-CO_2 brine injectivity in the Sixth Grayburg zone was slightly less than CO_2 injectivity while initial injectivity in the Ninth Massive San Andres was 50% less than that experienced with CO_2. Injectivity gradually recovered.

At project completion, the cumulative CO2 utilization ratios on the Grayburg and the Ninth Massive San Andres zones were about 8 MCF and 12 MCF per barrel, respectively. Oil recoveries were about 17% and 10%, respectively. The lower oil recovery and poorer CO_2 utilization experienced in the Ninth Massive San Andres zone can be partially attributed to the out-of zone injection identified in the logging observation wells. Post-projects simulation work attributed the reduced post-CO_2 injectivity experienced in the project to permeability hysteresis and wettability changes.

SIGNIFICANCE OF PROJECT

Promising oil recovery was experienced at Maljamar without resorting to WAG injection to control gas breakthrough in the heterogeneous reservoir.

GAS INJECTION--FIELD PROJECT DATA SUMMARY

Project Name:	Means San Andres Unit	Operator:	Exxon
Location:	Andrews County, New Mexico	Reservoir:	San Andres

Project Description
Size of Project: Field (172 patterns; 6,700 acres)
Injected Gas: Carbon Dioxide
Type of Process: Miscible Displacement
Process Design: Inject 40% HCPV CO_2 at 2:1 WAG ratio; drive water to depletion.
Reservoir Depletion at Start: - Mature Secondary
Date of First Injection: 11/01/83 Date of Latest Data: 01/01/88

RESERVOIR PARAMETERS

Parameter	Value	Comments
Depth, feet	4,400	
Reservoir Temperature, °F	--	
Permeability, millidarcy	20	
Oil Gravity, °API	29	
Reservoir Pressure, psia	2,000	
Minimum Miscibility Pressure, psia	2,000	
Oil Viscosity, centipoise	6	

Comments on Reservoir Parameters:

CONSTRAINTS ON EOR RECOVERY

(Listed in order of decreasing significance)

1. Description: Lift problems in rod and submersible pumps with high GOR production.
   Classification: Operations - Artificial Lift
   Limitation: Technology

MEANS SAN ANDRES
ANDREWS COUNTY, TEXACO

DISCUSSION

Carbon dioxide miscible flooding was started in the Means San Andres unit in late 1983. At that time, secondary production in the unit was in a relatively mature state. In the period from 1976 through 1983, the unit had been infill drilled to approximately 20-arce spacing using a basic 4-spot pattern. Concurrent with the carbon dioxide project, the unit was infill to approximately 10-arce spacing and converted to an inverted 9-spot pattern. The new development plan: (1) improved reservoir continuity, (2) allowed newly drilled wells to be the injection wells, and (3) considered directional permeability trends. The information gained during the recent waterflood development drilling and a single patter-carbon dioxide pilot exerted a major influence on a large scale development plan.

The initial one and one half-arce pilot test had established that waterflood residual oil could be mobilized, that heterogeneities were more severe than previously thought, that reduce CO_2-WAG injectivity was not a problem, and that CO_2 override did not occur. Displacement rests in native state core samples had previously determined that water blocking with WAG injectivity would not be a major problem. Simulation results were used to select the final slug design, a 40% HCPV CO_2 slug with a 2:1 WAG ratio. The 2:1 WAG ratio considered the 6 centipoise oil viscosity. Injection was to be maintained at 2000 psig--the approximate minimum miscibility pressure. The minimum miscibility pressure with either pure CO_2 or recycled field gas was essentially the same due to the low hydrocarbon GOR of the reservoir crude. Because the margin for error was small with the estimated formation parting pressure of 2700-2800 psig, parting pressures were measured in every injection well when CO_2 injection was started. Initial profile surveys were also performed. Annual surveys of parting pressure and injection profiles are being made to monitor (and correct) CO_2 flow trends. Reservoir pressure trends and injection/withdrawal balances are also closely monitored.

As of December 1987, cumulative carbon dioxide injection in the unit was about 11% HCPV with over 90% of the intended patterns receiving carbon dioxide. Total unit production was about double that at the time of initial CO_2 injection. Although tertiary response is masked by the numerous simultaneous changes made in the project, initial performance appears promising. The produced GOR (essentially all CO_2) after injected about one third of the planned CO_2 volume is about 2.3 MCF per barrel. No reductions in injectivity have been experienced with the WAG process. The WAG process is currently operated on a time basis rather than a volume basis due to the logistics involved with controlling a volume WAG process in a large project. From an operational standpoint, artificial lift problems are the only constraint referenced in the literature. When CO_2 breakthrough occurs, the additional gas production cannot be handled with the rod or submersible pumps which are predominant in the project. Jet pumps have successfully handled the additional gas production. In some cases the higher GOR wells flow.

SIGNIFICANCE OF PROJECT

The mass of recent data gained during the previous infill drilling program in the waterflood greatly facilitated the reservoir description for the carbon dioxide project. Initial results with the WAG process appear promising.

GAS INJECTION--FIELD PROJECT DATA SUMMARY

Project Name:	Northwest Purdy Unit	Operator:	Cities Service
Location:	Garvin County, Oklahoma	Reservoir:	Springer "A"

Project Description
Size of Project: Field (15, 5-spot patterns)
Injected Gas: Carbon Dioxide
Type of Process: Miscible Displacement
Process Design: Inject 30% HCPV CO_2 slug; WAG injection as needed to control gas production.
Reservoir Depletion at Start: Mature Secondary
Date of First Injection: 09/01/82 Date of Latest Data: 01/01/86

RESERVOIR PARAMETERS

Parameter	Value	Comments
Depth, feet	8,000	
Reservoir Temperature, °F	148	
Permeability, millidarcy	44	
Oil Gravity, °API	35	
Reservoir Pressure, psia	2,000	
Minimum Miscibility Pressure, psia	2,000	
Oil Viscosity, centipoise	0.7	

Comments on Reservoir Parameters:

CONSTRAINTS ON EOR RECOVERY
(Listed in order of decreasing significance)

1. Description: Downhole equipment damage in producers.
   Classification: Operations - Corrosion
   Limitation: Technology

2. Description: Submersible pumps are prone to lift problems with varying lift conditions associated with high gas production.
   Classification: Operations - Artificial Lift
   Limitation: Technology

NORTHWEST PURDY UNIT
GARVIN COUNTY, OKLAHOMA

DISCUSSION

Waterflood operations were in a mature state in the Northeast Purdy unit when miscible, carbon dioxide flooding operations were started in 1982. Ultimate primary and secondary recovery from the Springer "A" Sand was estimated at 36% of the original-oil-in-place. Geologically, the Springer "A" Sand can be divided into four distinct zones with the upper zone being most permeable. Vertical permeability is generally limited. Preproject injectivity testing confirmed that injection profiles with carbon dioxide were equal or better than experienced with waterflooding. Plans for injection of a 30% HCPV slug of carbon dioxide without alternating water based on simulation work which indicated recovery would be higher without WAG injection.

Early performance after three years of carbon dioxide injection is promising. In wells offsetting carbon dioxide injection wells, oil production was tripled while water production was decreased about 25%. Carbon dioxide production after three years was about 3 MCF per barrel. Production response and pressure transient tests have established the presence of directional permeability trends which were not evident in prior waterflooding. Carbon dioxide injection profiles have continued to be equal or better than experienced with water. Where injection profiles deteriorated, acid treatments restored the original profiles. Carbon dioxide injectivity has actually increased with time. In those patterns which have received their 30% HCPV carbon dioxide slug, water injectivity has been equal to that prior to gas injection. About one fourth of the patterns have been switched to WAG injection rather than gas only injection. WAG injection has been used in patterns which experienced gas channeling or low reservoir pressures.

Corrosion control in the producers has been the major operational problem. Continuous side stream flush treatments are used with wells equipped with submersible pumps. This procedure has provided adequate protection above the pump intake. While specialized metallurgy has protected this pump itself, corrosion damage in the casing below the pump intake has been evident. Rod pumps are batch treated; erosion/corrosion of rod boxes has been severe.

Submersible pump failure have also represented a problem. When carbon dioxide breakthrough occurs, the GLR increases rapidly. Accordingly, the electric motors rapidly become oversized by as much as 50%. Underload shutdowns have been reduced by modifying the shutdown load and/or using chokes to increase the backpressure. Pump efficiencies with the gassy fluids have been low even with gas separation equipment. Most failures of the pump section have been traced to insufficient fluid momentum to lift the impellers. Some wells possess sufficient energy to flow.

SIGNIFICANCE OF PROJECT

Gas channeling has not been prevalent with injection of a 30% HCPV carbon dioxide slug without WAG injection.

GAS INJECTION--FIELD PROJECT DATA SUMMARY

Project Name: SACROC Unit — Operator: Chevron
Location: Scurry County, Texas — Reservoir: Canyon Reef
Project Description
Size of Project: Field
Injected Gas: Carbon Dioxide
Type of Process: Miscible Displacement
Process Design: Inject 20% HCPV CO_2 (later reduce to 12% HCPV) using low WAG ratios.
Reservoir Depletion at Start: Mature Secondary
Date of First Injection: 01/01/72 — Date of Latest Data: 01/01/78

RESERVOIR PARAMETERS

Parameter	Value	Comments
Depth, feet	6,700	
Reservoir Temperature, °F	130	
Permeability, millidarcy	19	
Oil Gravity, °API	41	
Reservoir Pressure, psia	Variable	
Minimum Miscibility Pressure, psia	1,600	
Oil Viscosity, centipoise	0.4	

Comments on Reservoir Parameters:

CONSTRAINTS ON EOR RECOVERY
(Listed in order of decreasing significance)

1. Description: Rapid CO_2 breakthrough; poor injection profiles.
   Classification: Reservoir Heterogeneity
   Limitation: Technology

2. Description: Started Phase I CO_2 injection when (a) free gas saturation present and (b) pressure below MMP.
   Classification: Mobility Control
   Limitation: Management

SACROC UNIT
SCURRY COUNTY, TEXAS

DISCUSSION

The SACROC unit project represents one of the early, field scale projects conducted in a heterogeneous West Texas reservoir. The carbon dioxide flooding process was implemented in three phases due to CO_2 supply-recycle limitations. Although volumetric sweep efficiencies from 60% to 80 + % are projected after 5 years of carbon dioxide injection, the project was plagued by early CO_2 breakthrough. Analysis indicates that several interrelated factors contributed to the early dioxide breakthrough.

Reservoir Heterogeneity - The gross interval in the Canyon Reef reservoir averages 268 feet. Injection profiles during Phase I prior to remedial activities indicated that 50% of the injected gas was entering only 20% of the pay. Although remedial efforts including perforated liners and zonal isolation techniques improved profiles, reservoir heterogeneity was the dominant EOR constraint at SACROC.

Gas breakthrough was most adverse in Phase I where CO_2 injection was started when a free gas saturation still existed and when reservoir pressure was less than that required for miscibility. The adverse mobility associated with these conditions should have been avoided by repressuring and filling up the reservoir prior to carbon dioxide injection.

Phase III operations utilized experienced gained during earlier phases. As a result, early CO_2 breakthrough was reduced to manageable levels. WAG injection became a major element in controlling gas breakthrough problems.

The experience grained with carbon dioxide, miscible gas flooding at SACROC has been utilized in subsequent projects in heterogeneous reservoirs. Although advancing technology has not eliminated CO_2 breakthrough as a concern, early breakthrough has been managed to an extent that project viability is not a question.

SIGNIFICANCE OF PROJECT

The SACROC project represents one of the earliest carbon dioxide miscible floods in a heterogeneous reservoir. As a result, much of the technology used in recent CO_2 projects has evolved from the experience gained at SACROC.

GAS INJECTION--FIELD PROJECT DATA SUMMARY

Project Name:	Slaughter Estate Unit	Operator:	Amoco
Location:	Hockley County, Texas	Reservoir:	San Andres

Project Description
- Size of Project: Pilot (12 acre, double 5-spot pattern)
- Injected Gas: Carbon Dioxide
- Type of Process: Miscible Displacement
- Process Design: Inject 25% HCPV acid gas at 1:1 WAG ratio followed by 30% HCPV N_2 drive gas at 1:1 WAG ratio.
- Reservoir Depletion at Start: Mature Secondary
- Date of First Injection: 08/01/76 Date of Latest Data: 01/01/80

RESERVOIR PARAMETERS

Parameter	Value	Comments
Depth, feet	5,000	
Reservoir Temperature, °F	105	
Permeability, millidarcy	6	
Oil Gravity, °API	40	
Reservoir Pressure, psia	2,000	
Minimum Miscibility Pressure, psia	--	
Oil Viscosity, centipoise	2.0	

Comments on Reservoir Parameters:

CONSTRAINTS ON EOR RECOVERY
(Listed in order of decreasing significance)

1. Description: CO_2 WAG injectivity was 40% less than waterflood injectivity.
   Classification: Reduced Injectivity
   Limitation: Technology

2. Description: Rapid breakthrough of nitrogen drive gas even with WAG injection.
   Classification: Mobility Control
   Limitation: Technology

SLAUGHTER ESTATE UNIT PILOT
HOCKLEY COUNTY, TEXAS

DISCUSSION

The Slaughter Estate unit pilot was located in an area of the field which had not been waterflooded. Primary recovery of about 13% of the original-oil-in-place had created an initial gas saturation of 18% prior to waterflooding. Pilot waterflooding operations recovered 39% of the original-oil-in-place and provided a good indication of reservoir quality in the pilot area. Acid gas injection (72% CO_2, 28% H_2S) was started in 1976 when secondary production was in a mature state. Injection rates with a 1:1 WAG ratio were about 40% less than those experienced in the pilot waterflood. Initial response to the acid gas injection occurred after about 10% HCPV of injection. Although response on a pore volume basis agreed with preproject estimates, timing was later than anticipated due to the lower than planned injection rates. Injection of the 30% HCPV acid gas slug at a 1:1 WAG ratio was completed in 1979--about 3 years after initial injection. Drive gas injection with nitrogen at a 1:1 ratio was implemented immediately. Drive gas injectivity with the WAG process was approximately the same as experienced during waterflooding. Rapid breakthrough of the drive gas occurred; within one year only 37% of the injected drive gas was occurred; within one year only 37% of the injected drive gas was retained in the reservoir. Even with rapid breakthrough of the drive gas, high oil recoveries were observed in the pilot project. Through 1980, actual recovery was 17% of the original-oil-in-place with ultimate tertiary oil recovery projected at 20% to 25% of the original-oil-in-place.

SIGNIFICANCE OF PROJECT

Tertiary recovery in excess of 20% of the original-oil-in-place was realized in a watered-out reservoir even though poor mobility control was evident in the drive gas bank.

GAS INJECTION--FIELD PROJECT DATA SUMMARY

Project Name:	Timbalier Bay	Operator:	Chevron USA
Location:	Coastal Louisiana	Reservoir:	S-2B Sand

Project Description
- Size of Project: Pilot (Updip injection in 2 fault blocks)
- Injected Gas: Carbon Dioxide
- Type of Process: Gravity Stable, Miscible Displacement
- Process Design: Carbon dioxide slug (30% HCPV) displaced downdip by natural gas.

Reservoir Depletion at Start: Mature Primary
Date of First Injection: 04/01/84 Date of Latest Data: 07/01/85

RESERVOIR PARAMETERS

Parameter	Value	Comments
Depth, feet	7,400	
Reservoir Temperature, °F	180	
Permeability, millidarcy	7,400	
Oil Gravity, °API	39	
Reservoir Pressure, psia	3,400	
Minimum Miscibility Pressure, psia	3,500	
Oil Viscosity, centipoise	0.4	

Comments on Reservoir Parameters:

CONSTRAINTS ON EOR RECOVERY
(Listed in order of decreasing significance)

No constraint.

TIMBALIER BAY FIELD
COASTAL WATERS, LOUISIANA

DISCUSSION

The S-2B Sand in the Timbalier Bay field produced about 60% of the original-oil-in-place via a strong water drive--reservoir pressure had fallen only about 100 psig in 33 years of primary production. Gravity stable, miscible carbon dioxide injection was initiated in a watered-out sand section in two fault blocks. Oil saturation in the watered-out sand was at residual oil levels of 29%. The project was designed to displace residual oil from a 50 foot section of the reservoir. A 30% HCPV slug of carbon dioxide was injected over a 14 month period. Injection rates were maintained at 1/2 or less of the calculated gravity stable rate due to carbon dioxide supply considerations. The reservoir pressure approximated the minimum miscibility pressure measured in laboratory tests. Produced field gas was being used to displace the slug downdip. At a later date, plans were to re-inject the produced carbon dioxide along with field gas. Although an oil bank had not arrived at the producers as of the latest data available, production logging indicated that the oil-water contact had been lowered 17 feet implying that an oil bank was being formed.

SIGNIFICANCE OF PROJECT

Initial project monitoring indicates that the gravity stable, carbon dioxide process is mobilizing residual oil in a watered-out zone of the reservoir.

GAS INJECTION--FIELD PROJECT DATA SUMMARY

Project Name:	Two Freds Project	Operator:	HNG Fossil Fuels
Location:	West Texas	Reservoir:	Delaware Sand

Project Description
- Size of Project: Field
- Injected Gas: Carbon Dioxide
- Type of Process: Miscible Displacement
- Process Design: Inject about 40% HCPV CO_2 followed by drive with exhaust gas or water.

Reservoir Depletion at Start: Mature Secondary
Date of First Injection: 02/01/74 Date of Latest Data: 01/01/85

RESERVOIR PARAMETERS

Parameter	Value	Comments
Depth, feet	4,820	
Reservoir Temperature, °F	104	
Permeability, millidarcy	33	
Oil Gravity, °API	36	
Reservoir Pressure, psia	2,400	
Minimum Miscibility Pressure, psia	--	
Oil Viscosity, centipoise	1.5	

Comments on Reservoir Parameters:

CONSTRAINTS ON EOR RECOVERY
(Listed in order of decreasing significance)

1. Description: Reduced injectivity in West Side limited withdrawals and required using exhaust gas rather than water as the drive fluid.
   Classification: Reduced Injectivity
   Limitation: Technology

2. Description: Chemical costs represented 13% of field operational costs.
   Classification: Operations - Corrosion/Scale
   Limitation: Technology

TWO FREDS PROJECT
WEST TEXAS

DISCUSSION

The Delaware Sand in the Two Freds field is relatively clean and uniform where the reservoir is permeable. Localized permeability variations from interfingered sand-shale control well productivity. Although primary recovery via solution gas drive was typical (13% original-oil-in-place), secondary recovery was poor - only 4% of the original-oil-in-place. Calculated volumetric sweep efficiencies in the Eastern and Western portions of the field were 29% and 40% respectively.

Carbon dioxide injection was initiated in the East side in early 1974. Injectivity allowed sufficient CO_2 volumes to be injected to match withdrawals. As production response was observed, pattern modifications were made to allow more CO_2 to be injected to match withdrawals. Carbon dioxide was injected through the late 70s. At that time, drive water injection was attempted but low injectivity prevented matching withdrawals. Exhaust gas was chosen over nitrogen as an alternative drive agent based on contract considerations. Individual patterns were converted to drive gas injection after an average CO_2 slug volume of 55% of a mobile pore volume had been injected. When exhaust gas breakthrough was observed in less than six months, WAG injection was started. Water injectivity following exhaust gas injection was 30% greater than after CO_2 injection. WAG ratios have been kept low - less than 0.2. Through 1984 after 10 years of injection, cumulative CO_2 utilization was approaching 15 MCF per barrel with oil recovery being about 13% of the oil in place at flood start.

Carbon dioxide injection was expanded to the West side in 1979 and 1980. Injectors were specifically selected to have larger permeability-feet intervals than the producers to avoid the injection capacity problems experienced in the East side. Since CO_2 injection volumes are being restricted to match withdrawals, this plan has apparently been successful. With the observed higher injectivity, it is anticipated that water rather than exhaust gas can be used as the drive agent. Through 1974, less than 6% of the injected CO_2 has been produced. Cumulative CO_2 utilization through 1984 of nearly 17 MCF per barrel is overstated since production is still at its peak.

Operational problems have been relatively minor. Injection problems have been related to cement dissolution from the cement-lined tubing and distribution systems remaining from prior waterflood operations. Filtration at the injection wellhead plus a material replacement policy has resolved solids plugging. Producers require frequent corrosion and scale treatments. Flowing wells also require paraffin treatments. Total chemical costs in 1984 represented about 13% of the field operational costs. On a total cost basis, the approximate $12 per barrel cost is evenly split between field operational costs and compression/injectant costs.

SIGNIFICANCE OF PROJECT

Economic success in the Two Freds field project without special tax/governmental incentives illustrate that tertiary recovery can be attractive on its own merit.

GAS INJECTION--FIELD PROJECT DATA SUMMARY

Project Name: Weeks Island
Operator: Shell Oil
Location: Iberia Parish, LA
Reservoir: "S" Sand, Rsvr. B.

Project Description
- Size of Project: Pilot (Injection in isolated fault block)
- Injected Gas: Carbon Dioxide
- Type of Process: Gravity Stable, Miscible Displacement
- Process Design: Gas injection above gas-oil contact; downdip displacement of oil rim by balanced injection/withdrawal.

Reservoir Depletion at Start: Mature Primary
Date of First Injection: 10/04/78
Date of Latest Data: 01/01/88

RESERVOIR PARAMETERS

Parameter	Value	Comments
Depth, feet	13,000	
Reservoir Temperature, °F	225	
Permeability, millidarcy	1,200	
Oil Gravity, °API	32	
Reservoir Pressure, psia	5,100	
Minimum Miscibility Pressure, psia	5,100	
Oil Viscosity, centipoise	--	

Comments on Reservoir Parameters:
Reservoir is steeply dipping.

CONSTRAINTS ON EOR RECOVERY
(Listed in order of decreasing significance)

1. Description: Evident gas/water coning contributed to high recycle/injection costs and extended project life.
   Classification: Mobility Control
   Limitation: Technology

WEEKS ISLAND PROJECT
IBERIA PARISH, LOUISIANA

DISCUSSION

The S Sand, Reservoir B in the Weeks Island project is a steeply dipping, high permeability reservoir. The reservoir is well confining by faults. Oil production is realized from an oil rim located between a sizeable gas cap and an underlying aquifer. Primary production was realized by gas cap expansion and downdip water injection. When the carbon dioxide injection project was started, the thickness of the oil rim had been reduced to about 23 feet. The single producer in the reservoir was producing small oil volumes at high water cuts with rapidly increasing GOR's.

A mixture of carbon dioxide and natural gas was injected at a location just above the gas-oil contact. Natural gas was mixed with the carbon dioxide to decrease its density at reservoir conditions and increase the stability of the gravity displacement process. Production from a downdip producer was not started until eleven months after initial gas injection. During this preproduction period, water production from a well located further downdip balanced the injection volumes. Production logging indicated the thickness of the oil rim was increasing as a result of displacement of waterdrive residual oil--from 23 feet to about 57 feet. Initial oil production was characterized by high water cut and rapidly increasing carbon dioxide concentration. At a later date, a second producer was drilled and cored to evaluate the effectiveness of the displacement process and provide an additional withdrawal point. Oil saturation in the swept zone of the core averaged less than 2% as compared to a waterdrive residual oil saturation of 22%. Production logging in the new well after a one month shut-in period in the reservoir confirmed an essentially level carbon dioxide contact.

Operations during the latter stages of the project consisted of continuous recycling of produced gas and continued production of high water cut, high GOR oil from the two producers. At the present, production is in a mature stage of depletion. About 64% of the OIP at floodstart has been recovered with the estimated ultimate recovery being about 66%. The cumulative carbon dioxide utilization is approaching 8 MCF/bbl with 40% of the injected gas being purchased carbon dioxide. Post project simulation work indicated that coning of the gas from above and coning of the water from below strongly influenced production. Project life and costs were extended because of the additional recycling required to produce the oil rim with the degree of coning which was occurring.

SIGNIFICANCE OF PROJECT

The high recovery experienced in the Weeks Island project (about 66%) demonstrates the high efficiency of the gravity stable, miscible displacement process. In this instance, the high vertical permeability in the reservoir resulted in coning problems which extended project life and increased operating costs.

GAS INJECTION--FIELD PROJECT DATA SUMMARY

Project Name:	West Sussex Unit	Operator:	Conoco
Location:	Johnson County, Wyoming	Reservoir:	Shannon

Project Description
 Size of Project: Pilot (10 acre pilot - one injector, three producers)
 Injected Gas: Carbon Dioxide
 Type of Process: Miscible Displacement
 Process Design: Inject 30% PV CO_2 slug followed by 70% PV drive water injection.

Reservoir Depletion at Start: Mature Secondary
Date of First Injection: 12/21/82 Date of Latest Data: 11/01/85

RESERVOIR PARAMETERS

Parameter	Value	Comments
Depth, feet	2,950	
Reservoir Temperature, °F	104	
Permeability, millidarcy	29	
Oil Gravity, °API	39	
Reservoir Pressure, psia	2,000	
Minimum Miscibility Pressure, psia	1,600	
Oil Viscosity, centipoise	1.4	

Comments on Reservoir Parameters:

CONSTRAINTS ON EOR RECOVERY
(Listed in order of decreasing significance)

1. Description: One of three producers did not experience response.
 Classification: Reservoir Heterogeneity
 Limitation: Technology

2. Description: Paraffin restriction in producers.
 Classification: Operations - Artificial Lift
 Limitation: Technology

WEST SUSSEX UNIT
JOHNSON COUNTY, WYOMING

DISCUSSION

The carbon dioxide miscible flood was intentionally located in a watered-out portion of the waterflood to allow easy determination of tertiary oil. Saturation analysis of the drilled injector indicated a waterflood residual oil saturation of 28%. Pressure transient testing indicated the three producers were in pressure communication. An earlier pilot location was rejected when the injector drilled between three producers faulted out in the Shannon sand. Tracer surveys during a pre-CO_2 water injection phase indicated reservoir heterogeneities existed. Tracer was detected at Well No. 19 within three weeks while it took seven months to arrive at Well No. 13. Tracer was not detected at the downdip producer, No. 53.

Similar behavior was exhibited when carbon dioxide injection was initiated. Production response and carbon dioxide production was observed within one month at Well No. 19 while response did not occur at Well No. 13 unit about six months. Although poor sweep was evident between the injection well and No. 13, channeling did not develop to an extent that WAG injection was required. Production response of any significance was never observed in the downdip producer. Gravity segregation was discounted (reservoir dip angle of 8°) since the carbon dioxide flow trends were the same as observed during prior water injection. The downdip producer which never responded was a converted water injection well which had received 1.5 MMB of water injection. Near wellbore oil saturations may have been lower than the average 28% residual oil saturation.

Ultimate incremental production of 16,000 barrels is abut 80% of that predicted in preproject analysis. The ultimate carbon dioxide utilization ratio will be about 13 MCF/bbl of oil. With the exception of the pre-CO_2 tracer analysis, the project did not involve excessive front end engineering work. Results support a commercial scale project when an adequate carbon dioxide supply becomes available.

SIGNIFICANCE OF PROJECT

An economically successful pilot flood was conducted in a watered-out section of the reservoir. Gas channeling with carbon dioxide slug injection was not excessive even though reservoir heterogeneities were evident.

GAS INJECTION--FIELD PROJECT DATA SUMMARY

Project Name:	Wilmington Field	Operator:	Long Beach ODC
Location:	Johnson County, WY	Reservoir:	Tar Zone, Fault Block V.

Project Description
- Size of Project: Field (320 acres - 10 injectors, 47 producers)
- Injected Gas: Carbon Dioxide
- Type of Process: Miscible Displacement
- Process Design: WAG injection of CO_2/N_2 gas (about 85% CO_2).

Reservoir Depletion at Start: Mature Secondary
Date of First Injection: 02/01/82 Date of Latest Data: 01/01/85

RESERVOIR PARAMETERS

Parameter	Value	Comments
Depth, feet	2,300	
Reservoir Temperature, °F	130	
Permeability, millidarcy	100-1,000	
Oil Gravity, °API	14	
Reservoir Pressure, psia	1,100	
Minimum Miscibility Pressure, psia	3,000	
Oil Viscosity, centipoise	--	

Comments on Reservoir Parameters:

CONSTRAINTS ON EOR RECOVERY
(Listed in order of decreasing significance)

1. Description: Preferential gas injection in high permeability, aquifer zone.
   Classification: Injection Control
   Limitation: Technology

2. Description: Gas channeling in zones receiving high injection volume.
   Classification: Mobility Control
   Limitation: Technology

WILMINGTON FIELD
JOHNSON COUNTY, WYOMING

DISCUSSION

The immiscible carbon dioxide flood being conducted in the Tar Zone of Fault Block V, Wilmington field, has experienced problems with gas channeling and poor sweep due to preferential gas flow gas into a high permeability, high water saturation zone. Permeability in the three zones being flooded ranges from 100 to 1,000 md. Injection profiles in a particular injection well indicated this zone was taking 99% of the gas. A foam diversion technique was evaluated to improve conformance and areal sweep. A 40 to 100 foot foam bank was created in-situ by injecting a 1% solution of foaming agent in formation water and gas in eight, short alternating cycles. The resulting foam should have contained about 90% gas and 10% liquid. Initially, the foam diversion was successful. Injection profiles during subsequent gas injection indicated the offending zone was taking only 57% of the injected gas while gas injectivity was reduced by two thirds. Unfortunately, gas production in the offset producers was not reduced. This injected gas was either channeling through the new zone or entering the offending zone away from the near wellbore region. After the water portion of the WAG cycle, the percentage of gas entering the offending zone had increased to 88%. During the second gas cycle, both gas injectivity and vertical conformance returned to their prefoam values.

SIGNIFICANCE OF PROJECT

A foam diversion technique did not stop the excessive gas channeling and poor injection profiles being observed with immiscible carbon dioxide flooding in this heavy oil reservoir.

GAS INJECTION--FIELD PROJECT DATA SUMMARY

Project Name:	Wilmington Field	Operator:	Champlin
Location:	California	Reservoir:	Tar Zone, Fault Block III

Project Description
- Size of Project: Pilot (Four injectors, three producers)
- Injected Gas: Carbon Dioxide
- Type of Process: Immiscible Displacement
- Process Design: Inject CO_2 using equal time WAG cycle.

Reservoir Depletion at Start: Mature Secondary
Date of First Injection: 03/01/81 Date of Latest Data: 05/01/83

RESERVOIR PARAMETERS

Parameter	Value	Comments
Depth, feet	2,500	
Reservoir Temperature, °F	123	
Permeability, millidarcy	465	
Oil Gravity, °API	14	
Reservoir Pressure, psia	--	
Minimum Miscibility Pressure, psia	N/A	
Oil Viscosity, centipoise	283	

Comments on Reservoir Parameters:

CONSTRAINTS ON EOR RECOVERY
(Listed in order of decreasing significance)

No constraint.

WILMINGTON FIELD
JOHNSON COUNTY, WYOMING

DISCUSSION

The immiscible, carbon dioxide displacement pilot test in Fault Block III in the Wilmington field was conducted in two sands in the lower Tar Zone. At the approximate flooding pressure of 1,100 psig, oil viscosity is reduced to about 18 cp. Initial carbon dioxide injection consisted of warmed liquid CO_2 using WAG injection on an equal time cycle. The desired injection rates were achieved at wellhead pressures less than 1,000 psig. Later in the project life when gaseous, recycled CO_2 was injected, reduced injectivity was experienced. Gas injectivity during WAG injection increased when gas permeability in the near wellbore region was restored. Monthly injection profiles on all injectors during both the gas and water cycles indicate good injection distribution is being maintained. The favorable injection profiles can be attributed to flooding only two sands and to good mechanical completion with all pilot wells being newly drilled wells. Gas breakthrough has been relatively minor. After 2 years of carbon dioxide injection, the produced gas-oil ratio has stabilized at about 4 MCF per barrel and recycled CO_2 constitutes only about 1/3 of the injected gas stream. Oil production has increased sixfold with response being evident in all pilot producers. Water production has decreased by 2/3 causing some problems in maintaining the desired water injection rates since insufficient water is being produced. Ultimate carbon dioxide utilization of 6 MCF per barrel is being forecast.

SIGNIFICANCE OF PROJECT

Immiscible carbon dioxide flooding operations are being conducted in a heavy oil reservoir without experiencing excessive gas breakthrough or recycling.

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RESEARCH NEEDS TO MAXIMIZE ECONOMIC PRODUCIBILITY OF THE DOMESTIC OIL RESOURCE

PART II
EOR FIELD CASE HISTORIES

APPENDIX C
IN SITU COMBUSTION PROJECTS

TABLE OF CONTENTS

IN SITU COMBUSTION FIELD PROJECT DATA SUMMARY

Project Name: Bellevue Field — Operator: Getty Oil
Location: Bossier Parish, Louisiana — Reservoir: Nacatoch Sand

Project Description
- Size of Project: Field (350 producers, greater than 100 patterns)
- Type of Development: Pattern (Inverted 9-spots with infill wells)
- Injected Gas: Air
- Process Design: Wet combustion followed by heat scavenging

Reservoir Depletion at Start: Mature Primary
Date of First Injection: 06/01/63 — Date of Latest Data: 07/01/81

COMPARISON WITH NPC SCREENING CRITERIA

Parameter	NPC CRITERIA Implemented	NPC CRITERIA Advanced	Project Data	Outside Criteria
Depth, feet	11,500	NL	350	
Net Pay, feet	20	10	74	
Porosity, fraction*	0.20	0.15	0.38	
Oil Saturation x Porosity	0.08	0.08	0.20	
Permeability, millidarcy	35	10	1,094	
Oil Gravity, °API	10-35	NL	19	
Oil Viscosity, centipoise	5,000	5,000	450	
Transmissibility, (md-ft)/cP	5	NL	178	
Reservoir Pressure, psia	2,000	4,000		
Dip Angle, °	NL	NL	5	

*Ignored if oil saturation x porosity criteria exceeded. NL = no limitation on criteria.

Comments on exceptions to screening criteria: Reservoir parameters met all of the NPC screening criteria.

CONSTRAINTS ON EOR RECOVERY
(Listed in order of decreasing significance)

1. Description: Vertical permeability variation between upper and lower sands.
   Classification: Reservoir Heterogeneity
   Limitation: Technology

BELLEVUE FIELD
BOSSIER PARISH, LOUISIANA

DISCUSSION

The Bellevue field project, operated by Getty, represents one of the oldest, most successful in situ combustion projects in the United States. Sequential development of the project has enabled a systematic evaluation of the effects of key variables on oil recovery. In addition, phased development has allowed the operator to modify the procedures used in the latter part of the project to achieve improved oil recovery. As a result, actual incremental oil recovery in the Nacatoch Sand reservoir in 1981, 13 years after initial injection, was about 26% of the original-oil-in-place with overall project production still at its peak level to date. Ultimate incremental oil recovery of more than 50% of the original-oil-in-place was estimated by the operator. The high recovery is especially surprising considering the known permeability stratification. Within the project area, the Nacatoch Sand is divided into an upper and lower sand separated by a continuous, but nonsealing, lime stringer. Permeability of the upper sand is approximately twice that of the lower sand. Oil saturations at the start of the project were significantly lower in the upper, more permeable sand - 35% versus 69% in the lower sand. Even though injected fluids tended to follow the path of least resistance, high overall incremental recoveries were still realized.

Comparison of the oil recoveries realized with different injection sequences indicated that operations with a transitional period of alternating or simultaneous water injection exhibited better recovery than dry combustion followed by water injection for heat scavenging. Production response was accelerated while subsequent production decline rates were decreased. Not surprisingly, recovery comparisons indicated that smaller patterns with infill development wells exhibited higher oil recovery.

SIGNIFICANCE OF PROJECT

The Bellevue field project, operated by Getty, represents one of the largest in situ combustion projects in the United States. Development of the project over an 18-year period has allowed a systematic evaluation of oil recovery as a function of key factors.

IN SITU COMBUSTION FIELD PROJECT DATA SUMMARY

Project Name: Bodcau (Bellevue) Operator: Cities Service
Location: Bossier Parish, Louisiana Reservoir: Nacatoch Sand
Project Description
Size of Project: Field (Five patterns)
Type of Development: Pattern (Nine spots with infill wells)
Injected Gas: Air
Process Design: Wet combustion followed by heat scavenging
Reservoir Depletion at Start: Mature Primary
Date of First Injection: 05/05/76 Date of Latest Data:02/01/82

COMPARISON WITH NPC SCREENING CRITERIA

Parameter	NPC CRITERIA Implemented	NPC CRITERIA Advanced	Project Data	Outside Criteria
Depth, feet	11,500	NL	350	
Net Pay, feet	20	10	56	
Porosity, fraction*	0.20	0.15	0.34	
Oil Saturation x Porosity	0.08	0.08	0.18	
Permeability, millidarcy	35	10	700	
Oil Gravity, °API	10-35	NL	19	
Oil Viscosity, centipoise	5,000	5,000	676	
Transmissibility, (md-ft)/cP	5	NL	58	
Reservoir Pressure, psia	2,000	4,000	250	
Dip Angle, °	NL	NL	5	

*Ignored if oil saturation x porosity criteria exceeded. NL = no limitation on criteria.

Comments on exceptions to screening criteria: Reservoir parameters met all of the NPC screening criteria.

CONSTRAINTS ON EOR RECOVERY
(Listed in order of decreasing significance)

1. Description: Uneven combustion front due to varying vertical permeability.
   Classification: Reservoir Heterogeneity
   Limitation: Technology

2. Description: Significant oil production escaped from project area.
   Classification: Fluid Containment
   Limitation: Technology and Management

3. Description: Actual oil saturation was 54% versus preproject estimate of 73%.
   Classification: Reservoir Conditions
   Limitation: Technology and Management

BODCAU (BELLEVUE) FIELD
BOSSIER PARISH, LOUISIANA

DISCUSSION

The Nactoch Sand in the area of the Bodcau (Bellevue) in situ combustion project averages about 56 feet in thickness. Limestone layers, which are continuous across the project area, divide the reservoir into four discrete sands. The reservoir is bounded by dense limestone at the top and an oil-water contact at the bottom. Estimated ultimate primary production via liquid expansion and gravity drainage was about 15% of the original-oil-in-place. Prior to air injection, a strong north-to-south directional flow preference had been identified. Process design included two significant modifications to minimize gravity segregation effects. Firstly, patterns were elongated upstructure recognizing the tendency for injected gas to move upstructure. Secondly, air was injected in the lower portion of the sand while the water, which was injected simultaneously starting about 1 year after initial air injection, was injected in the upper portion of the sand. Using this approach, air injection was conducted from mid-1976 to mid-1981. When air injection was discontinued, the cumulative air-to-oil ratio was about 16 MCF per barrel. At that time, incremental oil recovery was already 32% of the original-oil-in-place. Ultimate incremental recovery with continued water injection was estimated to be about 35% of the original-oil-in-place. Primary recovery in the project area had been about 5% of the original-oil-in-place. Postproject economic analysis, using actual expenses and revenues with projections for late life economic performance, indicated the project had paid out in about 2.5 years and had yielded a rate of return around 40%.

Postproject technical analysis indicated several items of significance, as follows:

1. Although additional producers had been drilled in the upstructure portion of the patterns to produce exhibited oil response, significant oil still migrated across the lease line. If captured, actual project recovery would have been even better than indicated.

2. The combustion front tended to move toward the top of the sand as the distance from the injection well increased. Apparently, the interbedded limestone layers were not sealing and a degree of gravity segregation was occurring. In some cases, permeability stratification appeared to exhibit a stronger influence than gravity segregation on which zones were burned.

3. Wells located upstructure from the injection wells exhibited significantly better production response.

4. Operation of producers after breakthrough of the combustion front in the more permeable sands was facilitated by squeeze treatments of the affected zone (isolation) and by artificial

lift with hollow sucker rods. Hollow sucker rods permitted cooling water to be injected down the rod/tubing annulus.

Although reservoir heterogeneity and "escaped" oil limited project recovery, modifications to the process during the project minimized the adverse effects.

SIGNIFICANCE OF PROJECT

The Cities Service Bodcau (Bellevue) project represents one of the few economically successful in situ combustion projects using pattern development. Incremental recovery of about 35% of the original-oil-in-place was realized during a 7-year project life.

IN SITU COMBUSTION FIELD PROJECT DATA SUMMARY

Project Name: Brea-Olinda Field Operator: Union Oil
Location: Orange County, California Reservoir: Miocene M-6
Project Description
Size of Project: Field (Combustion in three fault blocks)
Type of Development: Irregular (One upstructure injector per block)
Injected Gas: Air
Process Design: Sequential dry combustion in lower, middle, and upper sand zones
Reservoir Depletion at Start: Mature Primary
Date of First Injection: 04/01/72 Date of Latest Data: 01/01/80

COMPARISON WITH NPC SCREENING CRITERIA

Parameter	NPC CRITERIA Implemented	NPC CRITERIA Advanced	Project Data	Outside Criteria
Depth, feet	11,500	NL	3,550	
Net Pay, feet	20	10	150	
Porosity, fraction*	0.20	0.15	0.29	
Oil Saturation x Porosity	0.08	0.08	0.15	
Permeability, millidarcy	35	10	300	
Oil Gravity, °API	10-35	NL	22	
Oil Viscosity, centipoise	5,000	5,000	20	
Transmissibility, (md-ft)/cP	5	NL	2,250	
Reservoir Pressure, psia	2,000	4,000		
Dip Angle, °	NL	NL	45	

*Ignored if oil saturation x porosity criteria exceeded. NL = no limitation on criteria.

Comments on exceptions to screening criteria: Reservoir parameters met all of the NPC screening criteria.

CONSTRAINTS ON EOR RECOVERY
(Listed in order of decreasing significance)

1. Description: Severe channeling - especially in one block.
   Classification: Reservoir Heterogeneity
   Limitation: Technology

2. Description: Performance required redrawing fault blocks.
   Classification: Reservoir Description
   Limitation: Technology and Management

3. Description: Injection well plugging due to lubricant/rust.
   Classification: Injectant Quality
   Limitation: Management

BREA-OLINDA FIELD
ORANGE COUNTY, CALIFORNIA

DISCUSSION

The M-6 Sand in the Brea-Olinda field is a thick interval containing 150 feet of net pay over a 200-foot interval. Individual sands within the total interval exhibit only general correlations from well to well. Complex faulting in the steeply dipping reservoir divides the reservoir into separate production blocks. Primary recovery from solution gas drive and gravity drainage was about 28% of the original-oil-in-place. Waterflooding and cyclic steam stimulation were unsuccessfully attempted prior to the in situ combustion project. Severe injection channeling limited waterflood recovery while insufficient response was observed from cyclic steam stimulation to justify the cost.

Initially, the in situ combustion project involved two fault blocks. The injection wells selected for each fault block were intended to be upstructure locations. When air injection was started, severe injection channeling was observed in one of two fault blocks. Nitrogen monitoring also indicated that three producers, initially believed to be in another fault block, were also in communication with the injection well. When no production response was observed after six months of injection, an alternate injection well higher on structure was selected. Although injection channeling was not as evident with the second injector, significant production response in the second fault block was almost immediate. Maximum response was observed in the downstructure wells centrally located in the fault block. Project monitoring indicated the combustion front moving across the top of the structure relatively uniformly. Uniform advancement downstructure was anticipated when the boundary faults were reached. Reservoir heterogeneities resulted in complete failure in one fault block while, apparently they did not affect performance in the second block.

At a later date, air injection was started in a third fault block. Minimal production response in the third block could be attributed to inadequate injectivity. Although the low injectivity experienced in the third fault block may have been due to reservoir heterogeneity, formation plugging is suspected considering the frequent injection well plugging observed in the other injection wells. Injection well plugging from iron oxide deposits necessitated frequent remedial treatments. Plugging was more severe whenever disturbances, such as injection interruptions or significant rate changes, occurred in the system. Acid treatments combined with reverse circulation of the injection wells proved most successful in restoring injectivity.

Injection well damage from hot spots - a major problem in many in situ combustion projects - was minimized at Brea-Olinda by limited entry completions and circulation of cooling water whenever temperature increases were detected. Limited entry completions (one or two shots per zone) provided better injection distribution, as well as being a physical barrier to oil flowback.

SIGNIFICANCE OF PROJECT

The reservoir heterogeneities which caused waterflooding to be unsuccessful were magnified in the in situ combustion process; favorable response was observed in only one of three fault blocks. Although process design may reduce the adverse effects of reservoir heterogeneities, severe heterogeneities are difficult to overcome.

IN SITU COMBUSTION FIELD PROJECT DATA SUMMARY

Project Name: Forest Hill Field   Operator: Greenwich Oil
Location: Wood County, Texas   Reservoir: Harris Sand
Project Description
Size of Project: Pilot (Fieldwide air, but pilot oxygen)
Type of Development: Irregular (One oxygen injector; six air injectors)
Injected Gas: Air, oxygen
Process Design: Wet combustion with air followed by dry oxygen
Reservoir Depletion at Start: Mature Primary
Date of First Injection: 07/01/76   Date of Latest Data: 01/01/82

COMPARISON WITH NPC SCREENING CRITERIA

Parameter	NPC CRITERIA Implemented	NPC CRITERIA Advanced	Project Data	Outside Criteria
Depth, feet	11,500	NL	4,800	
Net Pay, feet	20	10	15	
Porosity, fraction*	0.20	0.15	0.28	
Oil Saturation x Porosity	0.08	0.08	0.17	
Permeability, millidarcy	35	10	626	
Oil Gravity, °API	10-35	NL	10	
Oil Viscosity, centipoise	5,000	5,000	1,000	
Transmissibility, (md-ft)/cP	5	NL	14	
Reservoir Pressure, psia	2,000	4,000		
Dip Angle, °	NL	NL		

*Ignored if oil saturation x porosity criteria exceeded. NL = no limitation on criteria.

Comments on exceptions to screening criteria: Reservoir parameters met all of the NPC screening criteria.

CONSTRAINTS ON EOR RECOVERY
(Listed in order of decreasing significance)

1. Description: Future analysis will be difficult with limited monitoring/modeling of complex production history.
   Classification: Operations - Monitoring
   Limitation: Management

FOREST HILL FIELD
WOOD COUNTY, TEXAS

DISCUSSION

The reservoir environment at the start of oxygen injection in the Forest Hill field in January 1980 was quite complex. The field produced under primary from 1964 to 1976 when air was first injected in a single well. Although hot water and steam injection had been attempted during this primary phase, cumulative recovery in 1986 was only about 2.5% of the original-oil-in-place. From 1976 through 1980, air injection followed by water injection occurred in the injection wells. Since the water was not injected sequentially or simultaneously with the air, the process represented heat scavenging more than wet combustion. Oxygen enrichment was evaluated in a single injection well over a 2-year period with phased in oxygen concentrations of 40%, 60%, 80%, and 90%. Initial evaluation of oxygen-enriched injection indicated well productivities were 50% greater than with air injection. Long-term comparisons of oxygen and air efficiency will be complicated by the fact that decreasing oil prices in 1981 forced air and oxygen injection to be discontinued. Heat scavenging with water injection continued through 1985. Although late 1985 plans were to initiate oxygen injection in six wells, it is unknown whether oxygen injection was actually resumed. Cumulative recovery through 1984 still represented only about 5% of the original-oil-in-place. Although long-term success of the project is indeterminate, the project confirmed that oxygen injection cost less than air injection and that well productivity with oxygen injection was greater than with air injection.

SIGNIFICANCE OF PROJECT

Performance results from adjacent air and oxygen patterns in the Forest Hills project established the expected higher productivity with oxygen. The conditions where oxygen injection costs less than those with air were also defined.

IN SITU COMBUSTION FIELD PROJECT DATA SUMMARY

Project Name: Fry Unit — Operator: Marathon
Location: Crawford County, Illinois — Reservoir: Robinson Sand
Project Description
Size of Project: Field (Approximately 40 wells at peak)
Type of Development: Irregular (Three injectors spread along thick sand section)
Injected Gas: Air
Process Design: Dry combustion
Reservoir Depletion at Start: Mature Secondary
Date of First Injection: 08/01/61 Date of Latest Data: 01/01/69

COMPARISON WITH NPC SCREENING CRITERIA

Parameter	NPC CRITERIA Implemented	NPC CRITERIA Advanced	Project Data	Outside Criteria
Depth, feet	11,500	NL	900	
Net Pay, feet	20	10	50	
Porosity, fraction*	0.20	0.15	0.20	
Oil Saturation x Porosity	0.08	0.08	0.14	
Permeability, millidarcy	35	10	320	
Oil Gravity, °API	10-35	NL	29	
Oil Viscosity, centipoise	5,000	5,000	40	
Transmissibility, (md-ft)/cP	5	NL	400	
Reservoir Pressure, psia	2,000	4,000	300	
Dip Angle, °	NL	NL		

*Ignored if oil saturation x porosity criteria exceeded. NL = no limitation on criteria.

Comments on exceptions to screening criteria: Reservoir parameters met all of the NPC screening criteria.

CONSTRAINTS ON EOR RECOVERY
(Listed in order of decreasing significance)

1. Description: Low sweep in multizoned sand with directional flow trends.
   Classification: Reservoir Heterogeneity
   Limitation: Technology

2. Description: High cost - oil well rework, production stimulation treatment.
   Classification: Downhole Completion
   Limitation: Technology

FRY UNIT
CRAWFORD COUNTY, ILLINOIS

DISCUSSION

The commercial scale in situ combustion project in the Fry Unit was implemented after a single pattern pilot established the effectiveness of the process. The Robinson Sand in the project area is a point bar deposit with three sand intervals in the total sand. Extensive reservoir description and pilot performance established that the characteristics of each sand interval were quite different. These differing characteristics, as well as a directional flow preference along the depositional trend, controlled the movement of the combustion fronts in the commercial scale project. Process monitoring indicated the combustion fronts elongated parallel to the sand deposition trend with preferential movement in the thicker, more permeable sand. Vertical conformance was estimated at 60%. Areal sweep with an irregular pattern was subject to uncertainty. Ultimate incremental recovery approached 25% to 30% of original-oil-in-place.

Although the project was considered a technical success, several factors combined to cause the project to be uneconomic.

1. Front-end research/development/engineering costs were incurred with the extensive reservoir description effort. Unfortunately, the project would still not have paid out, even with these costs.

2. Reconditioning workovers were required in nearly every well since the field was originally developed in the early 1900s. A portion of these costs might be avoidable in fields of more recent vintage.

3. Fracture treatments were required to achieve adequate productivity in nearly a third of the producers. Besides increasing costs, these fracture treatments created local flow disturbances in the vicinity of the producers.

Even though the project was not profitable, it was significant in that it represented a pioneering project in the area of reservoir description.

SIGNIFICANCE OF PROJECT

Although the Fry project was an early in situ combustion project, comprehensive reservoir description methods were used. As a result, incremental recovery approached 30%. High capital and operating costs made the project uneconomic.

IN SITU COMBUSTION FIELD PROJECT DATA SUMMARY

Project Name: Glenn Hummel Field Operator: Sun Oil
Location: Wilson County, Texas Reservoir: Poth "A" Sand
Project Description
Size of Project: Field (544 acres - 30+ producers, four injectors)
Type of Development: Irregular (Injectors located upstructure)
Injected Gas: Air
Process Design: Dry combustion followed by heat scavenging
Reservoir Depletion at Start: Intermediate Primary
Date of First Injection: 01/01/68 Date of Latest Data: 04/01/78

COMPARISON WITH NPC SCREENING CRITERIA

Parameter	NPC CRITERIA Implemented	NPC CRITERIA Advanced	Project Data	Outside Criteria
Depth, feet	11,500	NL	2,400	
Net Pay, feet	20	10	9	Yes
Porosity, fraction*	0.20	0.15	0.36	
Oil Saturation x Porosity	0.08	0.08	0.25	
Permeability, millidarcy	35	10	1,000	
Oil Gravity, °API	10-35	NL	22	
Oil Viscosity, centipoise	5,000	5,000	74	
Transmissibility, (md-ft)/cP	5	NL	122	
Reservoir Pressure, psia	2,000	4,000	953	
Dip Angle, °	NL	NL		

*Ignored if oil saturation x porosity criteria exceeded. NL = no limitation on criteria.

Comments on exceptions to screening criteria: Reservoir parameters met all of the NPC screening criteria.

CONSTRAINTS ON EOR RECOVERY
(Listed in order of decreasing significance)

1. Description: Excessive casing leaks increased operating costs.
   Classification: Operations - Corrosion
   Limitation: Technology and Management

GLEN HUMMEL FIELD
WILSON COUNTY, TEXAS

DISCUSSION

Ultimate primary production in the Poth "A" Sand in the Glen Hummel field was estimated at about 11% of the original-oil-in-place. Production was from a relatively clean sand which averaged about 9 feet in thickness. Although the average pay thickness was less than ten feet, net pay in portions of the reservoir approached 30 feet.

Injection plans were to create a combustion front across the top of the structure using two to three wells located where reservoir thickness exceeded 10 feet. As the combustion front moved downstructure, burned-out producers might be converted to air injection. Ignition in the initial injection well was achieved with a downhole burner, while subsequent wells ignited spontaneously. Initial wellhead injection pressures were about 2,000 psia. Within 1 year after initial injection, production had doubled. When air injection was discontinued about 9 years after initial injection, incremental oil recovery was about 13% of the original-oil-in-place. Water injection for heat scavenging was started during the later stages of air injection. Initially, a fivefold production response was realized from the water injection. Although production data beyond the initial response was not available, additional incremental recovery of about 10% of the original-oil-in-place is estimated from heat scavenging. Process monitoring indicated the combustion fronts during air injection tended to burn downstructure through the thicker sand members. Since producers existed in the thinner zones on the edge of the reservoir, a portion of the oil bypassed by the combustion front was still produced by these wells. As a result, incremental oil recovery was still favorable even though combustion front movement had been uneven.

SIGNIFICANCE OF PROJECT

An economically successful in situ combustion project was conducted in a reservoir with average pay thickness less than 10 feet. Detrimental effects of the thin sand interval were minimized by locating the injectors in the thick sand portion of the reservoir.

IN SITU COMBUSTION FIELD PROJECT DATA SUMMARY

Project Name: Gloriana Field — Operator: Sun Oil
Location: Wilson County, Texas — Reservoir: Poth "A" Sand

Project Description
- Size of Project: Field (12 producers, three injectors)
- Type of Development: Irregular (Single line drive in elongated reservoir)
- Injected Gas: Air
- Process Design: Dry combustion
- Reservoir Depletion at Start: Mature Primary
- Date of First Injection: 05/01/69 — Date of Latest Data: 04/01/78

COMPARISON WITH NPC SCREENING CRITERIA

Parameter	NPC CRITERIA Implemented	Advanced	Project Data	Outside Criteria
Depth, feet	11,500	NL	1,680	
Net Pay, feet	20	10	5	Yes
Porosity, fraction*	0.20	0.15	0.35	
Oil Saturation x Porosity	0.08	0.08	0.18	
Permeability, millidarcy	35	10	1,000	
Oil Gravity, °API	10-35	NL	21	
Oil Viscosity, centipoise	5,000	5,000	174	
Transmissibility, (md-ft)/cP	5	NL	29	
Reservoir Pressure, psia	2,000	4,000	855	
Dip Angle, °	NL	NL		

*Ignored if oil saturation x porosity criteria exceeded. NL = no limitation on criteria.

Comments on exceptions to screening criteria: Reservoir parameters met all of the NPC screening criteria.

CONSTRAINTS ON EOR RECOVERY
(Listed in order of decreasing significance)

1. Description: High heat loss from thin sand.
   Classification: Reservoir Conditions
   Limitation: Technology

2. Description: Three wells found to be isolated from injector.
   Classification: Reservoir Description
   Limitation: Technology and Management

3. Description: Initial ignition delayed; insufficient monitoring.
   Classification: Injection Control
   Limitation: Management

GLORIANA FIELD
WILSON COUNTY, TEXAS

DISCUSSION

Ultimate primary production in the Poth "A" Sand in the Gloriana field was estimated at about 15% of the original-oil-in-place. Gravity drainage was considered to be the major primary producing mechanism. The Poth "A" Sand is a two-membered sand separated more or less continuously by a shale stringer. Total sand thickness varies from 0 to 10 feet with an average thickness of about 5 feet. Considering that the sand contains two members, the reservoir was considerably thinner than recommended for in situ combustion. The injection plan consisted of establishing a combustion line across the reservoir with three wells. Continued injection would then advance the combustion front for the length of the reservoir.

Air injection in the original injector failed to cause spontaneous ignition. Four months after initial injection, ignition was achieved with a catalytic ignition system. Approximately 1 year later, a second well in the planned line drive was converted to air injection when temperature monitoring indicated the impending arrival of the combustion front. Although air was injected in a third well, nitrogen monitoring in the produced gas indicated the third injector plus two additional producers were isolated from the main reservoir. Subsequently, all project injection was made in the original two injectors at a pressure of about 1,200 psia.

Air was injected for about 6 years, from May 1969 until December 1974, when air injection became uneconomical. Incremental oil production during the period was estimated at about 170,000 barrels or 5% of the original-oil-in-place. Subsequent water injection for heat scavenging increased incremental recovery to about 9% of the original-oil-in-place.

SIGNIFICANCE OF PROJECT

Low incremental recovery in the Gloriana in situ combustion project can be attributed to heat losses to the surrounding strata and reservoir heterogeneities which were not identified prior to the project.

IN SITU COMBUSTION FIELD PROJECT DATA SUMMARY

Project Name: Golden Lake
Operator: Husky Oil
Location: Lloydminster, Canada
Reservoir: Sparky Sand
Project Description
Size of Project: Pilot (Approximately 20 wells)
Type of Development: Pattern (One inverted 5-spot; two inverted 7-spots)
Injected Gas: Air
Process Design: Wet combustion starting 2 years after first injection
Reservoir Depletion at Start: Virgin Reservoir
Date of First Injection: 07/01/69 Date of Latest Data: 12/01/81

COMPARISON WITH NPC SCREENING CRITERIA

Parameter	NPC CRITERIA Implemented	NPC CRITERIA Advanced	Project Data	Outside Criteria
Depth, feet	11,500	NL	1,600	
Net Pay, feet	20	10	23	
Porosity, fraction*	0.20	0.15	0.35	
Oil Saturation x Porosity	0.08	0.08	0.29	
Permeability, millidarcy	35	10	1,200	
Oil Gravity, °API	10-35	NL	13	
Oil Viscosity, centipoise	5,000	5,000	3,500	
Transmissibility, (md-ft)/cP	5	NL	8	
Reservoir Pressure, psia	2,000	4,000	510	
Dip Angle, °	NL	NL		

*Ignored if oil saturation x porosity criteria exceeded. NL = no limitation on criteria.

Comments on exceptions to screening criteria: Reservoir parameters met all of the NPC screening criteria.

CONSTRAINTS ON EOR RECOVERY
(Listed in order of decreasing significance)

1. Description: Excessive sand damage in producers.
   Classification: Downhole Completion
   Limitation: Technology

2. Description: Channeling due to injection above formation parting pressure.
   Classification: Injection Control
   Limitation: Management

3. Description: Inadequate compression facilities; excess downtime.
   Classification: Facility Design
   Limitation: Management

GOLDEN LAKE PROJECT
LLOYDMINSTER, CANADA

DISCUSSION

The Golden Lake Sparky in situ combustion pilot was implemented when wells were initially drilled; thus, primary and tertiary production were produced simultaneously. The low, estimated primary recovery of 5% of the original-oil-in-place recognizes the unfavorable crude characteristics and the high operating costs associated with lifting a viscous crude from an unconsolidated sand. The pilot project consisted of an initial inverted 5-spot pattern where ignition occurred in July 1969, and an expansion phase consisting of two inverted 7-spot patterns which were ignited in November 1974. Incremental recovery above primary in both phases of the pilot is estimated to be in excess of 30% of the original-oil-in-place. In the original 5-spot pattern, total recovery about 13 years after ignition was about 40% of the original-oil-in-place with a cumulative air to incremental oil ration of 3.4 MCF per barrel. Simultaneous air/water injection at a ratio of 200 barrels per MMSCF was implemented about 2 years after ignition. Oxygen monitoring revealed that combustion efficiency throughout the project life was high (about 95%).

Primary problems experienced in the pilot were sand control in producers, injection channeling, and injection rate control. High vent gas rates with air-injection aggravated sand production problems from the unconsolidated sand. Although several sand control techniques were evaluated for controlling sand entry in the producers, efforts were unsuccessful. Overall conclusion was that it was more cost effective to produce the sand than to control its entry in the wellbore. Injection channeling through apparent high permeability streaks was recognized as a potential problem prior to the pilot. Experience gained during the pilot indicated that maintaining injection pressures below 800 psi prevented formation channeling. Injection in the original pattern at a pressure of about 1500 psig resulted in a channel which occurred within a four-hour period about seven weeks after initial injection. Channeling was so severe that the injection well was eventually redrilled. Unlike many reservoirs, channeling in the Sparky Sand did not appear to heal when injection pressures were subsequently reduced. Poor cement jobs contributed to injection channeling tendencies. Sand backflow in the injection wells during compressor interruptions also contributed to injection overpressuring.

Production response in the expansion phase was delayed due to inadequate compression facilities. During the initial 4 years of injection, actual injection averaged 400 MCF per day versus the design rate of 1200 MCF per day. Although production problems associated with high vent gas rates subsequently limited gas injection rates to 900 MCF per day, compression facilities were still seriously undersized.

SIGNIFICANCE OF PROJECT

The Golden Lake Sparky project demonstrated that, if oil saturation at flood start is high, economic recovery can be realized despite deficiencies in project management.

IN SITU COMBUSTION FIELD PROJECT DATA SUMMARY

Project Name: West Heidelberg Unit — Operator: Gulf Oil
Location: Jasper County, Mississippi — Reservoir: Cotton Valley
Project Description
- Size of Project: Field (13 producers; four injectors)
- Type of Development: Irregular (Injectors located upstructure)
- Injected Gas: Air
- Process Design: Dry combustion plus produced gas re-injection
- Reservoir Depletion at Start: Mature Primary
- Date of First Injection: 12/01/71 Date of Latest Data: 10/01/80

COMPARISON WITH NPC SCREENING CRITERIA

Parameter	NPC CRITERIA Implemented	NPC CRITERIA Advanced	Project Data	Outside Criteria
Depth, feet	11,500	NL	11,750	Yes
Net Pay, feet	20	10	65	
Porosity, fraction*	0.20	0.15	0.16	Yes
Oil Saturation x Porosity	0.08	0.08	0.12	
Permeability, millidarcy	35	10	70	
Oil Gravity, °API	10-35	NL	22	
Oil Viscosity, centipoise	5,000	5,000	6	
Transmissibility, (md-ft)/cP	5	NL	750	
Reservoir Pressure, psia	2,000	4,000	3,000	Yes
Dip Angle, °	NL	NL	10	

*Ignored if oil saturation x porosity criteria exceeded. NL = no limitation on criteria.

Comments on exceptions to screening criteria: Reservoir parameters met all of the NPC screening criteria.

CONSTRAINTS ON EOR RECOVERY
(Listed in order of decreasing significance)

1. Description: Unexpected breakthrough due to areal/vertical permeability.
   Classification: Reservoir Heterogeneity
   Limitation: Technology

2. Description: Explosion in compression facility - increased costs.
   Classification: Operations - Compression
   Limitation: Management

WEST HEIDELBERG UNIT
JASPER COUNTY, MISSISSIPPI

DISCUSSION

The Cotton Valley Fourth and Fifth Sands in the West Heidelberg Unit produced about 4.5% of the original-oil-in-place during the primary production phase via expansion of the undersaturated oil. Considering that the reservoir is at a depth of 11,750 feet, the crude oil exhibited an usually low oil gravity (15° to 27° API) and solution gas-oil ratio (100 SCF/Bbl). Air in situ combustion was chosen over waterflooding for enhanced oil recovery. Initially, air injection was conducted only in the Fifth Sand. Prior to air injection, squeeze cement workovers were performed in all producers to ensure that only the Fifth Sand was open in the producers. The air injection well was a converted producer. When air injection was started, process monitoring indicated that ignition had occurred and that all air was entering the Fifth Sand. Initial production response occurred with three months in one of the producers located farthest from the injector - an indication of reservoir heterogeneity. Within 5 years, production response and combustion gas breakthrough were apparent in all producers except two downstructure wells near the tar seal area. From 1978 to 1980, the project was expanded to the Fourth Sand. During the same period, combustion gas reinjection was established in both sands. Reinjection of the combustion gases eliminated produced gas disposal problems, assisted in maintaining reservoir pressure, and may have provided a degree of miscibility with the reservoir fluids.

In mid-1981, about 10 years after air injection began, incremental oil recovery was estimated at 2.26 million barrels or about 9% of the original-oil-in-place. At that time, the cumulative air injected/produced oil ratio was about 3.6 MCF per barrel; an additional 2.5 MCF per barrel of flue gas had been injected. Ultimate incremental oil recovery from both reservoirs was estimated at about 26% of the original-oil-in-place. Project payout occurred about 2 1/2 years after initial air injection. Operating costs of less than $4 per barrel (1980 $) provided a significant profit margin to operate the property to depletion.

Three operational factors deserve mention: injection system cleanliness, corrosion control, and injection monitoring. Initially, contamination of the injection system with excess lubricant and rust occurred. This contamination resulted in an explosion in the compression facility within 1 year after air injection began. Revised lubricant/cleaning procedures prevented further explosions. Although these revised procedures were stringent, total compressor downtime was less than 10%. Corrosion in the producers was adequately controlled without exotic metallurgy by using a continuous downhole inhibitor injection program. In the first 10 years of project life, corrosion damage was limited to replacing four tubing strings. Radioactive gas tracers, Krypton 85 and tritiated hydrogen, successfully monitored injected gas movement in the two sands. Tracer monitoring confirmed the areal and vertical permeability variations observed in the Fifth Sand and established that the two sands were not in communication. Effective management of these three factors contributed to the low operating costs attained in the project.

SIGNIFICANCE OF PROJECT

Economic incremental recovery was achieved in the West Heidelberg Unit from a reservoir nearly 12,000 feet deep. The use of an irregular injection pattern and reinjection of the produced gases contributed to economic operation with the required high pressure injection conditions.

IN SITU COMBUSTION FIELD PROJECT DATA SUMMARY

Project Name: So. Hospah Field Operator: Tenneco Oil
Location: Jasper County, Mississippi Reservoir: Lower Hospah Sand
Project Description
Size of Project: Pilot (Single pattern)
Type of Development: Pattern (Inverted 5-spot)
Injected Gas: Air
Process Design: Dry combustion
Reservoir Depletion at Start: Mature Primary
Date of First Injection: 11/01/80 Date of Latest Data: 06/01/81

COMPARISON WITH NPC SCREENING CRITERIA

Parameter	NPC CRITERIA Implemented	Advanced	Project Data	Outside Criteria
Depth, feet	11,500	NL	1,625	
Net Pay, feet	20	10	15	Yes
Porosity, fraction*	0.20	0.15	0.27	
Oil Saturation x Porosity	0.08	0.08	0.13	Yes
Permeability, millidarcy	35	10	1,100	
Oil Gravity, °API	10-35	NL	26	
Oil Viscosity, centipoise	5,000	5,000	55	
Transmissibility, (md-ft)/cP	5	NL	560	
Reservoir Pressure, psia	2,000	4,000	600	Yes
Dip Angle, °	NL	NL	1	

*Ignored if oil saturation x porosity criteria exceeded. NL = no limitation on criteria.

Comments on exceptions to screening criteria: Reservoir parameters met all of the NPC screening criteria.

CONSTRAINTS ON EOR RECOVERY
(Listed in order of decreasing significance)

1. Description: Oil column (15 feet) was only one-third.
   Classification: Reservoir Heterogeneity
   Limitation: Management

2. Description: Combustion front moved down to low oil saturation zone.
   Classification: Injection Control
   Limitation: Technology

SO. HOSPAH FIELD
MCKINLEY COUNTY, NEW MEXICO

DISCUSSION

Although the pilot in situ combustion project in the Lower Hospah Sand recovered about one-third of the original-oil-in-place in the oil zone, an extremely high air-to-oil ratio - over 70 MCF per barrel - caused the project to be an economic failure. Postproject analysis indicated that the reservoir conditions which the pilot encountered were significantly different than expected if the actual reservoir conditions had been correctly understood, the in situ project may not have been conducted.

The Lower Hospah Sand in the project area consisted of an oil sand underlain by an active aquifer. After primary production, gas-water injection had been conducted to saturate the crude oil with gas. When a sufficient volume of gas had been injected to saturate the crude, gas injection was discontinued while waterflooding was continued. When the in situ combustion project was started, the reservoir was in a mature state of secondary depletion. Prior to the project, it was anticipated a 28-foot oil column would be encountered. After the pilot wells were drilled, analysis indicated that the oil column was only 15 feet. The lower portion of the expected oil column had been effectively waterflooded since the residual oil saturation was about 17%, as compared to 15% in the aquifer zone.

Since the reservoir exhibited good vertical permeability and the waterflooded zone exhibited equal or better absolute permeability than the oil zone, the effective permeability to injected air in the waterflooded zone was significantly greater than in the oil column. Although air injection was limited to the top 10 feet of the oil column, postproject core wells indicated the combustion front moved downward to the waterflooded zone at a short distance from the injector. Since the fuel requirement for combustion nearly equaled the oil saturation in this zone, negligible incremental oil was recovered from the zone which ultimately received most of the injection. Core analysis also indicated that only partial combustion had occurred due to excessive heat losses.

SIGNIFICANCE OF PROJECT

Since economic failure in this project can be attributed to encountering significantly different reservoir conditions than anticipated, the project demonstrates how critical it is to accurately describe reservoir conditions prior to the project.

IN SITU COMBUSTION FIELD PROJECT DATA SUMMARY

Project Name: Marguerite Lake Operator: BP Resources Canada
Location: Alberta, Canada Reservoir: Cold Lake Bitumen
Project Description
Size of Project: Pilot (Four patterns with about 38 total wells)
Type of Development: Pattern (5-spots with delayed infill drilling)
Injected Gas: Oxygen
Process Design: Fracture-Assisted Steam Cycling plus Wet Combustion
Reservoir Depletion at Start: Virgin Reservoir
Date of First Injection: 06/01/78 Date of Latest Data: 01/01/84

COMPARISON WITH NPC SCREENING CRITERIA

Parameter	NPC CRITERIA Implemented	Advanced	Project Data	Outside Criteria
Depth, feet	11,500	NL	1,480	
Net Pay, feet	20	10	75	
Porosity, fraction*	0.20	0.15	0.30	
Oil Saturation x Porosity	0.08	0.08	0.19	
Permeability, millidarcy	35	10		
Oil Gravity, °API	10-35	NL	11	
Oil Viscosity, centipoise	5,000	5,000	99,000	Yes
Transmissibility, (md-ft)/cP	5	NL		Yes
Reservoir Pressure, psia	2,000	4,000	5	
Dip Angle, °	NL	NL	1	

*Ignored if oil saturation x porosity criteria exceeded. NL = no limitation on criteria.

Comments on exceptions to screening criteria: Reservoir parameters met all of the NPC screening criteria.

CONSTRAINTS ON EOR RECOVERY

(Listed in order of decreasing significance)

No constraint.

MARGUERITE LAKE PROJECT ALBERTA PROVINCE, CANADA

DISCUSSION

The Marguerite Lake project represents a combined process enhanced oil recovery project where fracture-assisted steam cycling and oxygen in situ combustion were combined to produce the bitumen which is immobile at original reservoir conditions. The initial phase of the process consists of six to nine steam cycles. To achieve steam injection at reasonable rates, injection wells are fractured. The resulting fractures, which are strongly oriented on a northeast to southwest orientation, create a conductive channel. During the cyclic steam phase, the reservoir in the channel is heated to a temperature sufficient to support spontaneous ignition/combustion. Recovery from the cyclic steam process ranges from 15% to 20% of the original-oil-in-place. As a follow-up to cyclic steam, the operator selected oxygen rather than air injection on the basis of reduced injection and gas handling costs alone. Although effects were not quantified, beneficial effects (oil swelling, viscosity reduction) were anticipated from the additional CO_2 production. The additional CO_2 production should promote oil movement from the bulk of the reservoir into the conductive channel created during the cyclic steam process. Alternating water-oxygen injection was used to reduce fuel requirements and optimize heat scavenging. Since effective utilization of the conductive channels was a critical element of process design, oxygen injection wells were located in the channels, rather than outside of the channels as would normally be expected. Although specific recovery efficiencies were not stated in the literature, plans as of late 1985 were to expand the process to field scale in the early 1990s. The Marguerite Lake project represents a state-of-the-art project where two thermal processes (cyclic steam and in situ combustion) were combined to create a process tailored to the unique characteristics of bitumen sand production.

Facilities/operational design anticipated and minimized operational problems. Injection well corrosion with alternating oxygen-water injection was minimized by providing an air flush period between the oxygen and water injection periods. Uninterrupted injection was provided by an operational and standby oxygen supply system, as well as contingency plans for water injection in the event that both the operational and standby oxygen supplies were depleted or unavailable. Explosion hazards associated with oxygen breakthrough in the producers were reduced by continuous oxygen monitoring. When oxygen level exceed 1%, producers were protected from further breakthrough by placing them on steam injection. Experience indicated that, when these wells were placed back on production, oxygen breakthrough did not recur. Besides reducing explosion and wellbore damage hazards, this procedure promoted efficient oxygen utilization. Producers were protected from combustion front breakthrough in a similar fashion. Although several monitoring techniques were used, bottom-hole temperature monitoring proved to be the only reliable method of detecting the arrival of the combustion front at the producers. Oil treating was successfully accomplished with heat, diluent, and chemical. To some extent, emulsion forming tendencies were lower than normally encountered in in situ combustion projects because the water pH remained in the 6 to 8 range. Higher than normal pHs were attributed to minimal low temperature oxidation and the buffering effect of the carbonate cements in the reservoir.

SIGNIFICANCE OF PROJECT

The Marguerite Lake project, a recent project, effectively used state-of-the-art process and operations technology to mobilize sufficient bitumen to make the process viable on a commercial scale.

IN SITU COMBUSTION FIELD PROJECT DATA SUMMARY

Project Name: Midway Sunset Field — Operator: Mobil Oil
Location: Kern County, California — Reservoir: Moco Sand

Project Description

Size of Project: Field (Approximately 35 wells; 5 injectors)

Type of Development: Irregular (Upstructure injectors; injectors completed in one or more sands)

Injected Gas: Air

Process Design: Dry Combustion with one or more injectors open in each sand

Reservoir Depletion at Start: Early Primary

Date of First Injection: 01/01/68 Date of Latest Data: 09/01/78

COMPARISON WITH NPC SCREENING CRITERIA

Parameter	NPC CRITERIA Implemented	NPC CRITERIA Advanced	Project Data	Outside Criteria
Depth, feet	11,500	NL	2,500	
Net Pay, feet	20	10	129	
Porosity, fraction*	0.20	0.15	0.36	
Oil Saturation x Porosity	0.08	0.08	0.27	
Permeability, millidarcy	35	10	1,575	
Oil Gravity, °API	10-35	NL	14	
Oil Viscosity, centipoise	5,000	5,000	110	
Transmissibility, (md-ft)/cP	5	NL	1,850	
Reservoir Pressure, psia	2,000	4,000	1,000	
Dip Angle, °	NL	NL	30	

*Ignored if oil saturation x porosity criteria exceeded. NL = no limitation on criteria.

Comments on exceptions to screening criteria: Reservoir parameters met all of the NPC screening criteria.

CONSTRAINTS ON EOR RECOVERY

(Listed in order of decreasing significance)

1. Description: Uneven injection balance between sands in multizone reservoirs.
   Classification: Reservoir Heterogeneity
   Limitation: Technology

2. Description: High temperature damage in both injectors/producers.
   Classification: Reservoir Heterogeneity
   Limitation: Technology

MIDWAY SUNSET FIELD
KERN COUNTY, CALIFORNIA

DISCUSSION

The Moco sandstone in the Midway Sunset field consists of six sands over a 1,500-foot gross interval. Dip angle ranges from 25° to 40°. Although the productive horizons are generally separated by interbedded shales, some sands do merge at downstructure locations. Transmissibility of the individual horizons is quite variable. To maintain injection balance, five injectors were located upstructure with various combinations of sands open to injection. Injection balance between sands was monitored by periodic radioactive tracer surveys. Producers were open in all developed sands. Injection/production operations with the multiple sand reservoir presented unique challenges.

In the injection wells, ignition in the various sands occurred at different rates. As a result, high injection well temperatures were often observed in sands long after initial ignition occurred. With the combustion fronts at varying differences from the wellbore, uninterrupted air injection during the early phase of the project was especially critical to preventing burnback. Completions which utilized cemented and perforated liners exhibited better mechanical durability. In the producers, the combustion fronts in the different sands arrived at different times. To control downhole temperature and sustain production until all sands had burned through, the tubing was landed near bottom. When temperature monitoring indicated a combustion front was approaching the well, sufficient cooling water was circulated down the tubing/casing annulus to keep temperatures below 500°F. Gravel packs were utilized to control sand abrasion in the producers.

The limited upstructure injection well pattern used in the different sands promoted high efficiency. Oxygen utilization approached 100%. The instantaneous air-to-oil rate 12 years after initial injection was still only 4 to 6 MCF per barrel. If producers were damaged due to combustion front breakthrough, production could be sustained by alternative producers. In a pattern flood, alternative producers are not available to sustain production in that event. Process monitoring indicated the combustion fronts were burning a channel down the structure, rather than advancing down the structure uniformly. Although the sweep pattern was not ideal, it was expected the front would burn outward on structure once the downstructure reservoir limit was reached. As of late 1985, cumulative production from the project (primary plus incremental due to in situ combustion) was approaching 50% of the original-oil-in-place.

SIGNIFICANCE OF PROJECT

Specialized completion/operations techniques and the irregular injection pattern contributed significantly to successful fireflooding of the thick, multizoned Moco sandstone reservoir.

IN SITU COMBUSTION FIELD PROJECT DATA SUMMARY

Project Name: Miga Field   Operator: Gulf Oil
Location: Venezuela   Reservoir: P_{2-3} Sand

Project Description
Size of Project: Field (24 producers; two alternating injectors)
Type of Development: Irregular (One upstructure injector; one downstructure injector)
Injected Gas: Air
Process Design: Dry Combustion; switched from #1 to #2 injector at 5 years
Reservoir Depletion at Start: Intermediate Primary
Date of First Injection: 04/01/64   Date of Latest Data: 01/01/75

COMPARISON WITH NPC SCREENING CRITERIA

Parameter	NPC CRITERIA Implemented	NPC CRITERIA Advanced	Project Data	Outside Criteria
Depth, feet	11,500	NL	4,050	
Net Pay, feet	20	10	20	
Porosity, fraction*	0.20	0.15	0.23	
Oil Saturation x Porosity	0.08	0.08	0.17	
Permeability, millidarcy	35	10	5,000	
Oil Gravity, °API	10-35	NL	14	
Oil Viscosity, centipoise	5,000	5,000	300	
Transmissibility, (md-ft)/cP	5	NL	400	
Reservoir Pressure, psia	2,000	4,000		
Dip Angle, °	NL	NL	2	

*Ignored if oil saturation x porosity criteria exceeded. NL = no limitation on criteria.

Comments on exceptions to screening criteria: Reservoir parameters met all of the NPC screening criteria.

CONSTRAINTS ON EOR RECOVERY
(Listed in order of decreasing significance)

1. Description: Severe water channeling prevented wet combustion.
   Classification: Reservoir Heterogeneity
   Limitation: Technology

2. Description: Fault locations were significantly different than anticipated.
   Classification: Reservoir Description
   Limitation: Technology and Management

MIGA FIELD
VENEZUELA

DISCUSSION

The P_{2-3} Sand in the Miga field is an elongated channel sand from 1/4- to 1/2-mile wide and over 3 miles in length. Sand thickness varies from 10 to 20 feet. In situ combustion was started about 4 years after primary production began. The initial injection well was selected at a location believed to be near a sealing fault on the upstructure end of the field. Subsequent development indicated the fault was farther away than originally thought; thus, the initial injector location actually represented a midstructure location. During the early stages of injection, liquid withdrawals were restricted once gas breakthrough was observed. Air injection and gas withdrawal were maintained at high, but equal, rates. At a later date, when the reservoir had been energized, liquid/gas withdrawals with the heavy crude were unable to balance injection, even with all wells flowing. As a result, three additional producers were drilled to provide greater withdrawal capacity. After 5 years of air injection in the initial well, injection was switched to a downstructure well. Modelling studies had indicated the life of the producers would be extended by the change in injection well location. Although water injection was attempted in the original air injector to scavenge heat and prevent oil resaturation, rapid water channeling to the offset producer occurred. When a mechanical failure occurred shortly thereafter, the water injection plan was abandoned.

After 10 years of air injection, total field recovery was approaching 16% of the original-oil-in-place with two-thirds of this recovery attributed to the combustion process. Volume calculations indicated about 16% of the reservoir had been swept by the combustion front at that time. Ultimate recovery projections of 50% or more of the oil-in-place were made by the operator. Although recovery was efficient, the irregular pattern using a single injection well caused the project life to be extended.

SIGNIFICANCE OF PROJECT

The Miga project demonstrated the high recoveries possible with in situ combustion while illustrating the extended project lives generally experienced with irregular pattern projects.

IN SITU COMBUSTION FIELD PROJECT DATA SUMMARY

Project Name: Posesti Operator: Romania
Location: Romania Reservoir: Meotian Sand
Project Description
Size of Project: Field (Approximately 15 wells)
Type of Development: Irregular (Upstructure in fault blocks)
Injected Gas: Air
Process Design: Dry Combustion
Reservoir Depletion at Start: Mature Primary
Date of First Injection: 02/01/71 Date of Latest Data: 10/01/81

COMPARISON WITH NPC SCREENING CRITERIA

Parameter	NPC CRITERIA		Project Data	Outside Criteria
	Implemented	Advanced		
Depth, feet	11,500	NL	1,200	
Net Pay, feet	20	10	33	
Porosity, fraction*	0.20	0.15	0.27	
Oil Saturation x Porosity	0.08	0.08		
Permeability, millidarcy	35	10	300	
Oil Gravity, °API	10-35	NL	30	
Oil Viscosity, centipoise	5,000	5,000	15	
Transmissibility, (md-ft)/cP	5	NL		
Reservoir Pressure, psia	2,000	4,000		
Dip Angle, °	NL	NL	20	

*Ignored if oil saturation x porosity criteria exceeded. NL = no limitation on criteria.

Comments on exceptions to screening criteria: Reservoir parameters met all of the NPC screening criteria.

CONSTRAINTS ON EOR RECOVERY
(Listed in order of decreasing significance)

No constraint.

POSESTI PROJECT
ROMANIA

DISCUSSION

The Posesti project utilizes the line drive concept developed in the Suplacu de Barcau project in a steeply dipping, nonviscous crude oil reservoir. The air injectors are located updip near a small, undeveloped gas cap. Ultimate primary recovery in this nonviscous crude oil reservoir was estimated to be 25% of the original-oil-in-place when the in situ combustion process was started late in the primary depletion stage. Incremental recovery from the combustion project is estimated to be equal to primary recovery.

Because the gas cap in the Posesti reservoir was relatively small and undeveloped, the line drive pattern was located upstructure near the gas-oil contact. If the gas cap had been larger and the oil less viscous, Romania's experience indicates that a midstructure line drive location would have been more favorable. In that case, light ends from the combustion process would move upstructure with the combustion gases and condense in the bulk oil. When condensed in the bulk oil, the light ends would be produced by either the upstructure wells or the downstructure wells, depending on the extent to which gravity segregation causes the bulk oil to flow downward.

SIGNIFICANCE OF PROJECT

Recovery from the Posesti project demonstrates how injection well location can be used to maximize gravity drainage effects in steeply dipping reservoirs.

IN SITU COMBUSTION FIELD PROJECT DATA SUMMARY

Project Name: Schoonebeek   Operator: Shell Oil
Location: Netherlands   Reservoir: Sandstone
Project Description
Size of Project: Pilot (Three patterns)
Type of Development: Pattern (7-spots located on equal strike)
Injected Gas: Air
Process Design: Wet Combustion starting 2 years after initial air injection
Reservoir Depletion at Start: Mature Primary
Date of First Injection: 07/01/60   Date of Latest Data: 01/01/67

COMPARISON WITH NPC SCREENING CRITERIA

Parameter	NPC CRITERIA Implemented	Advanced	Project Data	Outside Criteria
Depth, feet	11,500	NL	2,500	
Net Pay, feet	20	10		
Porosity, fraction*	0.20	0.15		
Oil Saturation x Porosity	0.08	0.08		
Permeability, millidarcy	35	10	3,000	
Oil Gravity, °API	10-35	NL		
Oil Viscosity, centipoise	5,000	5,000	175	
Transmissibility, (md-ft)/cP	5	NL		
Reservoir Pressure, psia	2,000	4,000		
Dip Angle, °	NL	NL	8	

*Ignored if oil saturation x porosity criteria exceeded. NL = no limitation on criteria.

Comments on exceptions to screening criteria: Reservoir parameters met all of the NPC screening criteria.

CONSTRAINTS ON EOR RECOVERY
(Listed in order of decreasing significance)

1. Description: Premature combustion front breakthrough with free gas saturation at flood start.
   Classification: Mobility Control
   Limitation: Technology and Management

2. Description: Producers lost when premature combustion front breakthrough occurred.
   Classification: Downhole Completion
   Limitation: Technology

3. Description: In-depth formation plugging caused reduced injectivity and productivity.
   Classification: Operations - Formation Plugging
   Limitation: Technology

SCHOONEBEEK PROJECT
NETHERLANDS

DISCUSSION

The Schoonebeek in situ combustion project consisted of three 7-spot patterns located upstructure in a moderately dipping reservoir. Primary production in the area by solution gas drive was about 4% of the original-oil-in-place. A free gas saturation existed in the reservoir at the start of the project. Initially, the project was operated as a dry combustion project. Rapid breakthrough of the combustion front was implied, since negligible production response was attributed to losing producers due to the destructive temperature conditions. Prior to abandoning the unsuccessful dry combustion project, one pattern was converted to wet combustion. When favorable production response occurred, the remaining patterns were converted to wet combustion. Ultimately, a fivefold production in crease was realized. Reduced injectivity was experienced due to in-depth formation plugging from asphaltene/paraffin disposition.

SIGNIFICANCE OF PROJECT

Real time process monitoring enabled the Schoonebeek project to be successful. Process monitoring led to an unsuccessful dry combustion project being converted to a wet combustion project where production was increase fivefold.

IN SITU COMBUSTION FIELD PROJECT DATA SUMMARY

Project Name: Sloss Field | Operator: Amoco
Location: Kimball County, Nebraska | Reservoir: Muddy J-1
Project Description
Size of Project: Field (10 patterns)
Type of Development: Pattern (5-spots; some patterns irregular)
Injected Gas: Air
Process Design: Delayed Wet Combustion with simultaneous air/water injection
Reservoir Depletion at Start: Mature Secondary
Date of First Injection: 03/01/67 Date of Latest Data: 07/01/71

COMPARISON WITH NPC SCREENING CRITERIA

Parameter	NPC CRITERIA Implemented	NPC CRITERIA Advanced	Project Data	Outside Criteria
Depth, feet	11,500	NL	6,000	
Net Pay, feet	20	10	14	Yes
Porosity, fraction*	0.20	0.15	0.19	Yes
Oil Saturation x Porosity	0.08	0.08	0.06	Yes
Permeability, millidarcy	35	10	191	
Oil Gravity, °API	10-35	NL	39	Yes
Oil Viscosity, centipoise	5,000	5,000	1	
Transmissibility, (md-ft)/cP	5	NL	3,340	
Reservoir Pressure, psia	2,000	4,000	2,300	Yes
Dip Angle, °	NL	NL	8	

*Ignored if oil saturation x porosity criteria exceeded. NL = no limitation on criteria.

Comments on exceptions to screening criteria: Reservoir parameters met all of the NPC screening criteria.

CONSTRAINTS ON EOR RECOVERY
(Listed in order of decreasing significance)

1. Description: Uncertain oil saturation - 17% to 51%.
   Classification: Reservoir Conditions
   Limitation: Technology

2. Description: Actual permeability _ of expected; low sweep.
   Classification: Reservoir Heterogeneity
   Limitation: Technology

3. Description: Undesirable, high air-water injection ratio resulted from failure to design rate flexibility in air compression facilities.
   Classification: Facility Design
   Limitation: Management

SLOSS FIELD
KIMBALL COUNTY, NEBRASKA

DISCUSSION

The Muddy J-1 Sand in the Sloss field was in a mature state of waterflood depletion when the in situ combustion project was initiated. The field scale project discussed herein followed a single pattern pilot which lasted for 3 years, from 1963 through 1966. Although the original pilot recovered significant oil, determination of the incremental oil due to in situ combustion was uncertain due to known fluid movement, both into and from the pattern area. Directional permeability trends which had been evident in the waterflood were pronounced in the original pilot. Performance analysis was also complicated by uncertainty in the residual oil saturation at floodstart. Oil saturation estimates ranged from 17% to 51%, depending on the method used to estimate saturation. When it became apparent that the variables which influenced the pilot prevented answering the basic question, "Was the process economical?" the pilot was expanded to field scale. With a field scale project, fluid migration and directional permeability effects would not be as pronounced and economies of scale could be realized in the surface facilities.

The initial 6-pattern field project, where injection was started in early 1967, was expanded to 10 patterns by 1969. Although the Sloss field project was a wet combustion process, water injection did not occur until eight months after injection. Water injection was delayed because many of the injectors would not take water due to near wellbore damage. Besides formation damage, core analysis revealed permeabilities in the project area were less than half of those encountered in the pilot area. As a result, project water injection averaged about half the intended rate. Air injection rates were fixed by compression equipment design which did not allow operations at partial capacity. Accordingly, the air-to-water ratio throughout the project life was significantly higher than planned - about 1.3 MCF per barrel actual versus 0.7 MCF per barrel planned. The higher than desired air-to-water ratio, where maximum heat efficiency was not realized from the combustion process, contributed to the high air-to-oil ratio experienced in the project - over 21 MCF per barrel on a lifetime basis. Reservoir heterogeneities - directional permeability and permeability stratification - also contributed to the unfavorable air-to-oil ratio. Periodic loss of one or more producers in a pattern from premature breakthrough of the combustion front resulted in oil being lost or trapped in certain patterns.

In a postproject analysis, areal sweep efficiency was estimated at 50% while the volumetric sweep efficiency was estimated at 14%. Postcombustion core analysis indicated the combustion front preferentially flooded the upper portion of the pay sand. Although permeability variations were partially responsible, segregation of the air and water in the injection wellbore with simultaneous air/water injection was suspected. With air-water separation in the injection wellbore, a dry combustion process was postulated for the upper part of the zone with waterflooding in the lower part of the zone. Although the postulated mechanism could have occurred, it appears unlikely in a zone where total thickness varied from 5 to 15 feet.

SIGNIFICANCE OF PROJECT

Since several reservoir parameters were outside of the NPC-implemented screening criteria, chances for success were minimal under ideal conditions. Exhibited reservoir heterogeneities compounded an already marginal application.

IN SITU COMBUSTION FIELD PROJECT DATA SUMMARY

Project Name: Suplacu de Barcau   Operator: Romania
Location: Romania   Reservoir: Sandstone
Project Description
Size of Project: Field (Largest project with extended history)
Type of Development: Pattern (Advancing line drive - three-mile front)
Injected Gas: Air
Process Design: Dry Combustion followed by heat scavenging
Reservoir Depletion at Start: Early Primary
Date of First Injection: 04/01/64   Date of Latest Data: 09/01/81

COMPARISON WITH NPC SCREENING CRITERIA

Parameter	NPC CRITERIA Implemented	NPC CRITERIA Advanced	Project Data	Outside Criteria
Depth, feet	11,500	NL	800	
Net Pay, feet	20	10	63	
Porosity, fraction*	0.20	0.15	0.32	
Oil Saturation x Porosity	0.08	0.08	0.27	
Permeability, millidarcy	35	10	1,722	
Oil Gravity, °API	10-35	NL	16	
Oil Viscosity, centipoise	5,000	5,000	2,000	
Transmissibility, (md-ft)/cP	5	NL	54	
Reservoir Pressure, psia	2,000	4,000		
Dip Angle, °	NL	NL	8	

*Ignored if oil saturation x porosity criteria exceeded. NL = no limitation on criteria.

Comments on exceptions to screening criteria: Reservoir parameters met all of the NPC screening criteria.

CONSTRAINTS ON EOR RECOVERY
(Listed in order of decreasing significance)

1. Description: Combustion front sweeping only upper one-third of sand.
   Classification: Gravity Segregation
   Limitation: Technology

2. Description: Formation cratering in injection well near top of sand.
   Classification: Downhole Completion
   Limitation: Technology

SUPLACU de BARCAU PROJECT
ROMANIA

DISCUSSION

The Suplacu de Barcau in situ combustion project represents the world's largest operating project. Air injection was initiated in 1964 when primary production had reached its peak level. Without the in situ combustion project, ultimate primary recovery was estimated to be about 8% of the original-oil-in-place. The combustion project utilizes a line drive pattern advancing downdip with a line of air injectors, followed by a line of water injectors. As the combustion front breaks through to the producers, they are converted to air injection. At peak development, a three-mile combustion front existed with over 400 wells. With this development pattern, the air-to-oil ratio has been about 9 MCF per barrel. Although the process is recovering over 50% of the original-oil-in-place in zones swept by the combustion process, the combustion zone tends to exhibit gravity segregation. Reportedly, only the upper third of the pay zone is actually being swept by the combustion front. Although the lower portion of the zone is not swept by the combustion front, incremental production is still realized from the lower zone due to viscosity reduction/drive water injection effects.

At Suplacu, in situ combustion was selected over steam because it exhibited better recovery and because of the country's experience/manufacturing capability for compression equipment. Success in the Suplacu project has spawned other commercial scale combustion projects in Romania. Significantly, most projects utilize an advancing line drive concept rather than a repeating pattern. Although project life is lengthened because the entire reservoir is not developed simultaneously, the risk of losing all producers in a repeating pattern due to premature breakthrough of the combustion front is avoided.

SIGNIFICANCE OF PROJECT

The Suplacu de Barcau project represents the world's largest in situ combustion project with an extended performance history. Economic success in this project has spawned several commercial scale in situ combustion projects in Romania.

IN SITU COMBUSTION FIELD PROJECT DATA SUMMARY

Project Name: Talco Field　　Operator: Exxon
Location: East Texas　　Reservoir: Paluxy Carr "A"
Project Description
Size of Project: Pilot
Type of Development: Pattern (7-spot)
Injected Gas: Air
Process Design: Dry Combustion (Low injectivity prevented wet combustion)
Reservoir Depletion at Start: Mature Secondary
Date of First Injection: 07/01/72　　Date of Latest Data: 10/01/75

COMPARISON WITH NPC SCREENING CRITERIA

Parameter	NPC CRITERIA Implemented	Advanced	Project Data	Outside Criteria
Depth, feet	11,500	NL	4,250	
Net Pay, feet	20	10	18	Yes
Porosity, fraction*	0.20	0.15	0.26	
Oil Saturation x Porosity	0.08	0.08		Yes
Permeability, millidarcy	35	10	1,000	
Oil Gravity, °API	10-35	NL	22	
Oil Viscosity, centipoise	5,000	5,000	26	
Transmissibility, (md-ft)/cP	5	NL	692	
Reservoir Pressure, psia	2,000	4,000	400	
Dip Angle, °	NL	NL		

*Ignored if oil saturation x porosity criteria exceeded. NL = no limitation on criteria.

Comments on exceptions to screening criteria: Oil saturation at start of project was essentially unknown.

CONSTRAINTS ON EOR RECOVERY
(Listed in order of decreasing significance)

1. Description: Inadequate definition of (a) oil saturation at start, and (b) air-water injectivity.
   Classification: Process Design
   Limitation: Technology and Management

2. Description: Channeling prior to ignition; uneven front movement.
   Classification: Reservoir Heterogeneity
   Limitation: Technology

3. Description: Excessive treating costs.
   Classification: Operations - Oil Treating/Corrosion
   Limitation: Technology and Management

TALCO FIELD
EAST TEXAS

DISCUSSION

The Paluxy Carr "A" Sand in the Talco field was in a mature state of waterflood depletion when the in situ combustion project was started in 1972. Although the oil saturation was known to be low, minimal effort was reported concerning the definition of oil saturation and whether the saturation was sufficient to support combustion. When air injection was started, ignition was not achieved until 6 months later. Although the delayed ignition was attributed to air channeling, the known low oil saturation could have been a factor in the delayed ignition. Air injection was continued through late 1975 with only minimal production response. Combustion gas monitoring indicated the combustion front was moving preferentially in a northeast direction. Attempts to convert the process to wet combustion were unsuccessful since water injectivity could not be established with alternate air/water injection. Acid stimulation of the injector restored air injectivity but failed to affect water injectivity. The project was discontinued in October 1975 due to excessive oil treating/corrosion costs considering the minimal production response observed in the project.

Reservoir conditions in the project were marginal with respect to oil saturation and reservoir thickness. With marginal application conditions, preproject engineering analysis is more critical to project success. The documentation reported in public sources implies inadequate definition of both the reservoir conditions at floodstart and the performance of the in situ combustion process in the reservoir.

SIGNIFICANCE OF PROJECT

Inadequate definition of oil saturation, directional flow trends, and water injectivity prior to the project resulted in the in situ combustion process being attempted in an environment where chances for success were minimal.

IN SITU COMBUSTION FIELD PROJECT DATA SUMMARY

Project Name: East Tia Juana   Operator: Shell Oil
Location: Venezuela   Reservoir: Sandstone
Project Description
Size of Project: Pilot
Type of Development: Pattern (7-spot with separate injectors for upper and lower sand)
Injected Gas: Air
Process Design: Steam stimulation followed by wet combustion
Reservoir Depletion at Start: Mature Secondary
Date of First Injection: 01/01/66   Date of Latest Data: 01/01/69

COMPARISON WITH NPC SCREENING CRITERIA

Parameter	NPC CRITERIA Implemented	NPC CRITERIA Advanced	Project Data	Outside Criteria
Depth, feet	11,500	NL	1,560	
Net Pay, feet	20	10	60	
Porosity, fraction*	0.20	0.15	0.41	
Oil Saturation x Porosity	0.08	0.08	0.30	
Permeability, millidarcy	35	10	5,000	
Oil Gravity, °API	10-35	NL	13	
Oil Viscosity, centipoise	5,000	5,000	6,000	Yes
Transmissibility, (md-ft)/cP	5	NL	58	
Reservoir Pressure, psia	2,000	4,000		
Dip Angle, °	NL	NL	4	

*Ignored if oil saturation x porosity criteria exceeded. NL = no limitation on criteria.

Comments on exceptions to screening criteria: Steam stimulation of producers and injectors was used to promote initial displacement.

CONSTRAINTS ON EOR RECOVERY
(Listed in order of decreasing significance)

1. Description: Production response in only 1/2 of producers.
   Classification: Reservoir Heterogeneity
   Limitation: Technology

2. Description: Corrosion damage in injectors with alternating air/water injection.
   Classification: Operations - Corrosion
   Limitation: Technology

3. Description: Sand erosion in producers.
   Classification: Downhole Completion
   Limitation: Technology

EAST TIA JUANA PROJECT
VENEZUELA

DISCUSSION

Prior to the wet combustion project in the East Tia Juana project, both a dry combustion and a steam drive pilot had been conducted in the reservoir. In these prior pilots, strong directional permeability trends had limited response to only one or two of the six producers. In the wet combustion pilot, more uniform injection distribution was promoted by steam slug injection in the injection well and steam stimulation of the producers. Air and water injection were alternated on a weekly basis. Although corrosion problems were experienced with alternating air-water injection, reduced injectivity was not identified as a problem. Separate injectors were used for the upper and lower sands. With this approach, production response was observed in nearly half of the offset producers. Although improved production response was observed, reservoir heterogeneity still reduced project recovery significantly.

SIGNIFICANCE OF PROJECT

In the East Tia Juana project, the wet combustion process caused more production response than was experienced with prior dry combustion and steam projects. Even so, recovery was severely limited by reservoir heterogeneity.

IN SITU COMBUSTION FIELD PROJECT DATA SUMMARY

Project Name: Trix-Liz Field Operator: Sun Oil
Location: Titus County, Texas Reservoir: Woodbine "C"
Project Description
Size of Project: Field (10 producers; three injectors)
Type of Development: Irregular (Injectors located in thick sand)
Injected Gas: Air
Process Design: Dry combustion (Clays prevented water injection)
Reservoir Depletion at Start: Mature Primary
Date of First Injection: 09/01/68 Date of Latest Data: 01/01/72

COMPARISON WITH NPC SCREENING CRITERIA

Parameter	NPC CRITERIA Implemented	NPC CRITERIA Advanced	Project Data	Outside Criteria
Depth, feet	11,500	NL	3,650	
Net Pay, feet	20	10	9	Yes
Porosity, fraction*	0.20	0.15	0.28	
Oil Saturation x Porosity	0.08	0.08	0.18	
Permeability, millidarcy	35	10	500	
Oil Gravity, °API	10-35	NL	24	
Oil Viscosity, centipoise	5,000	5,000	26	
Transmissibility, (md-ft)/cP	5	NL	173	
Reservoir Pressure, psia	2,000	4,000	1,950	
Dip Angle, °	NL	NL	4	

*Ignored if oil saturation x porosity criteria exceeded. NL = no limitation on criteria.

Comments on exceptions to screening criteria: Net pay ranged from 0 to 20 feet in the reservoir.

CONSTRAINTS ON EOR RECOVERY
(Listed in order of decreasing significance)

1. Description: One producer was found to be isolated from injector.
   Classification: Reservoir Description
   Limitation: Technology and Management

TRIX-LIZ FIELD
TITUS COUNTY, TEXAS

DISCUSSION

The Woodbine "C" Sand in the Trix-Liz field contains interbedded sand and shale members. Ultimate primary production from the undersaturated oil reservoir was estimated at about 15% of the original-oil-in-place. When air injection was started in 1968, the field was nearing primary depletion since cumulative recovery was approaching 14% of the original-oil-in-place. Waterflooding of the reservoir had been discounted because of the high clay content/water sensitivity of the reservoir. Although average sand thickness in the reservoir was less than 10 feet, sand thickness in the heart of the reservoir was greater than 20 feet. Initial air injection occurred in a single air injector in the heart of the reservoir. Within 2-1/2 years, two additional injectors had been added in the heart of the reservoir to form a uniform combustion front. Subsequent air injection displaced this large front to the thinner edges of the reservoir.

Within three months after initial injection, oil production had doubled. Oil production was about 3.5 times preproject levels 3 years after air injection was started. At that point, incremental recovery due to in situ combustion was already 8% of the original-oil-in-place. Although further production data was not available, ultimate incremental recovery should be at least 15% to 20% of the original-oil-in-place.

SIGNIFICANCE OF PROJECT

An economically successful in situ combustion project was conducted in a reservoir with average pay thickness less than 10 feet. Detrimental effects of the thin sand interval were minimized by locating the injectors in the thick sand portion of the reservoir.

IN SITU COMBUSTION FIELD PROJECT DATA SUMMARY

Project Name: North Ward Estes   Operator: Gulf Oil
Location: Ward County, Texas   Reservoir: Yates Sand
Project Description
Size of Project: Pilot (Phase I, 5-spot; Phase II, 9-spot)
Type of Development: Pattern (Inverted 5- and 9-spot patterns)
Injected Gas: Air
Process Design: Dry combustion
Reservoir Depletion at Start: Mature Secondary
Date of First Injection: 04/01/78   Date of Latest Data: 12/01/80

COMPARISON WITH NPC SCREENING CRITERIA

Parameter	NPC CRITERIA Implemented	NPC CRITERIA Advanced	Project Data	Outside Criteria
Depth, feet	11,500	NL	2,700	
Net Pay, feet	20	10	25	
Porosity, fraction*	0.20	0.15	0.20	
Oil Saturation x Porosity	0.08	0.08	0.07	Yes
Permeability, millidarcy	35	10	88	
Oil Gravity, °API	10-35	NL	33	
Oil Viscosity, centipoise	5,000	5,000	1	
Transmissibility, (md-ft)/cP	5	NL	1,570	
Reservoir Pressure, psia	2,000	4,000	1,400	
Dip Angle, °	NL	NL		

*Ignored if oil saturation x porosity criteria exceeded. NL = no limitation on criteria.

Comments on exceptions to screening criteria: Several parameters are considered to be marginal for in situ combustion.

CONSTRAINTS ON EOR RECOVERY
(Listed in order of decreasing significance)

1. Description: Insufficient coke/oil saturation to sustain combustion.
   Classification: Reservoir Conditions
   Limitation: Technology

2. Description: Natural fracture system caused distorted flow.
   Classification: Reservoir Heterogeneity
   Limitation: Technology

3. Description: Lower oil saturation and stronger fracture system than anticipated.
   Classification: Reservoir Description
   Limitation: Management

NORTH WARD ESTES PROJECT
WARD COUNTY, TEXAS

DISCUSSION

The North Ward Estes project represented an application of the in situ combustion process in a light oil reservoir producing at a mature stage of waterflood depletion. Oil saturation at the time of injection was estimated to be in the 30% to 35% range. Laboratory evaluation indicated ignition could be obtained by resaturating the injection wellbore with crude oil prior to ignition. If injection was maintained at 2,000 psia pressure, the combustion reaction could be sustained. In the initial inverted 5-spot pattern, the injection wellbore was not resaturated with crude oil prior to ignition. Under these conditions, 13 days were required to achieve ignition. Although ignition was indicated, oxygen breakthrough in the produced gas occurred within two days. When continued produced gas monitoring indicated that only a low temperature oxidation process was occurring, air injection was terminated in this pattern.

The Phase II pilot, an inverted 9-spot pattern, was located in an area of the reservoir where higher oil saturations were believed to exist. To promote ignition, the injection wellbore was resaturated with 480 barrels of a 22° API crude. Ignition was achieved within five days. Although oxygen breakthrough to producers was not as severe as in the first pattern, it still occurred. Two core test wells were drilled to evaluate the combustion process. The first core test well was drilled one year after air injection began, at a distance of 100 feet from the injection well - a location calculated to be behind the combustion front. Analysis indicated a clean burn had occurred with a maximum formation temperature of 750°F. The second core test well, which was drilled at a location intended to be in front of the combustion front, encountered two fingers which the burn front had passed. Since no clay alterations were evident, the maximum formation temperature which had occurred was less than 400°F. Process monitoring indicated oil saturations were insufficient to propagate the combustion front. Only trace amounts of oil were ever recovered in either phase of the project.

From an operational standpoint, corrosion control costs were excessive with the higher produced oxygen levels associated with incomplete combustion. A combination of metallurgy, coatings, and chemical treatment was required to achieve a degree of control. From a reservoir standpoint, injection channeling from either a natural fracture system or directional permeability trends was much more severe than anticipated in the project design phase. Additional reservoir description may have predicted the channeling tendencies more accurately.

SIGNIFICANCE OF PROJECT

Failure of the in situ combustion process in the North "Ward Estes project emphasizes the critical importance of oil saturation, especially in light oil reservoirs. This project represented a step out beyond accepted screening criteria.

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RESEARCH NEEDS TO MAXIMIZE ECONOMIC PRODUCIBILITY OF THE DOMESTIC OIL RESOURCE

PART II
EOR FIELD CASE HISTORIES

APPENDIX D

STEAM FIELD PROJECTS

TABLE OF CONTENTS

STEAM FIELD PROJECT DATA SUMMARY

Project Name: "200" Sand
Operator: Santa Fe
Location: Kern County, California
Reservoir: Spellacy Sand
Project Description
Size of Project: Field (14, inverted 7-spot patterns)
Steam Process: Steamdrive

Process Design: Continuous steamdrive

Reservoir Depletion at Start: Mature Primary
Date of First Injection: 10/01/75
Date of Latest Data: 01/01/81

COMPARISON WITH NPC SCREENING CRITERIA

Parameter	NPC CRITERIA Implemented	NPC CRITERIA Advanced	Project Data	Outside Criteria
Depth, feet	3,000	5,000	600	
Net Pay, feet	20	15	150	
Porosity, fraction*	0.20	0.15	0.30	
Oil Saturation x Porosity	0.10	0.08	0.18	
Permeability, millidarcy	250	10	2,250	
Oil Gravity, °API	10-35	NL	12	
Oil Viscosity, centipoise	15,000		6,500	
Transmissibility, (md-ft)/cP	5	NL	53	
Reservoir Pressure, psia	1,500	2,000	40	
Dip Angle, °	NL	NL	10	

*Ignored if oil saturation x porosity criteria exceeded. NL = no limitation on criteria.

Comments on exceptions to screening criteria: Reservoir parameters met all of the NPC screening criteria.

CONSTRAINTS ON EOR RECOVERY

(Listed in order of decreasing significance)

1. Description: Inadequate steam generation facilities.
   Classification: Facility Design
   Limitation: Management

"200 SAND" DEMONSTRATION PROJECT
KERN COUNTY, CALIFORNIA

DISCUSSION

The initial steamdrive operation in the "200 Sand" consisted of four inverted 7-spot patterns. Primary recovery in the heavy oil reservoir had been low and prior steam stimulation attempts had been uneconomic. Initial steam injection occurred in October 1975. Production increased from a preproject level of about 20 barrels of oil per day to 200 barrels of oil per day at its peak. Project response during the initial years was delayed by inadequate steam generation facilities. Although specific recovery estimates were not reported, the project was expanded from 4 to 14 patterns in 1980.

SIGNIFICANCE OF PROJECT

Steamdrive operations in the "200 Sand" project were successful whereas steam stimulation operations had been uneconomic.

STEAM FIELD PROJECT DATA SUMMARY

Project Name: Brea Field
Location: California
Operator: Shell Oil
Reservoir: Lower "B" Sand
Project Description
Size of Project: Field (Three injectors - 13 producers)
Steam Process: Steamdrive
Process Design: Updip injection in 66°-dip angle reservoir.

Reservoir Depletion at Start: Mature Primary
Date of First Injection: 04/01/63 Date of Latest Data: 1/01/72

COMPARISON WITH NPC SCREENING CRITERIA

Parameter	NPC CRITERIA Implemented	NPC CRITERIA Advanced	Project Data	Outside Criteria
Depth, feet	3,000	5,000	4,800	Yes
Net Pay, feet	20	15	550	
Porosity, fraction*	0.20	0.15	0.22	
Oil Saturation x Porosity	0.10	0.08	0.11	
Permeability, millidarcy	250	10	70	Yes
Oil Gravity, °API	10-35	NL	24	
Oil Viscosity, centipoise	15,000		6	
Transmissibility, (md-ft)/cP	5	NL	4,100	
Reservoir Pressure, psia	1,500	2,000	110	
Dip Angle, °	NL	NL	66	

*Ignored if oil saturation x porosity criteria exceeded. NL = no limitation on criteria.

Comments on exceptions to screening criteria: Two parameters fell outside of the NPC screening criteria.

CONSTRAINTS ON EOR RECOVERY
(Listed in order of decreasing significance)

1. Description: Casing - Tubing failures
   Classification: Downhole Completion
   Limitation: Technology

BREA FIELD
CALIFORNIA

DISCUSSION

The Brea field project maximized oil recovery by utilizing updip injection in a reservoir with a 66° dip angle. Recovery resulted primarily from gravity displacement of a solvent bank formed by steam distillation of the relatively light oil. With the steep dip angle, only minor distortions from true gravity displacement were evident. Saturation analysis of cores indicated post-steam residual oil saturations of 8% or less.

The primary constraint on economic recovery was casing failures with the high temperature and high pressure conditions required for injection with a reservoir depth of 4,800 feet. Current technology has resolved most of the problems which were experienced in this early project.

SIGNIFICANCE OF PROJECT

The Brea field project utilized gravity effects, which normally are detrimental to steamdrive, to enhance steamdrive recovery in a steeply dipping reservoir.

STEAM FIELD PROJECT DATA SUMMARY

Project Name: Cat Canyon Field — Operator: Getty Oil
Location: Santa Barbara County, California — Reservoir: SI-B Sand

Project Description
- Size of Project: Pilot (Four 5-acre, inverted 5-spot patterns)
- Steam Process: Steamdrive
- Process Design: Continuous steam injection with supplemental steam stimulation of nonresponding producers.
- Reservoir Depletion at Start: Mature Primary
- Date of First Injection: 04/01/77 — Date of Latest Data: 06/01/80

COMPARISON WITH NPC SCREENING CRITERIA

Parameter	NPC CRITERIA Implemented	NPC CRITERIA Advanced	Project Data	Outside Criteria
Depth, feet	3,000	5,000	4,800	
Net Pay, feet	20	15	80	
Porosity, fraction*	0.20	0.15	0.31	
Oil Saturation x Porosity	0.10	0.08	0.20	
Permeability, millidarcy	250	10	1,000	
Oil Gravity, °API	10-35	NL	9	Yes
Oil Viscosity, centipoise	15,000		25,000	Yes
Transmissibility, (md-ft)/cP	5	NL	3	Yes
Reservoir Pressure, psia	1,500	2,000		
Dip Angle, °	NL	NL		

*Ignored if oil saturation x porosity criteria exceeded. NL = no limitation on criteria.

Comments on exceptions to screening criteria: Oil viscosity significantly exceeded the NPC screening criteria.

CONSTRAINTS ON EOR RECOVERY

(Listed in order of decreasing significance)

1. Description: Severe steam channeling; channeling aggravated by overinjection.
   Classification: Reservoir Heterogeneity
   Limitation: Technology and Management

2. Description: Actual sand face steam quality was near zero.
   Classification: Injectant Quality
   Limitation: Management

3. Description: Sand control; thermal packer failures; inadequate lift capacity.
   Classification: Downhole Completion
   Limitation: Technology and Management

CAT CANYON FIELD
SANTA BARBARA COUNTY, CALIFORNIA

DISCUSSION

The steamdrive project in the William Holdings lease in the Cat Canyon field represented an attempt to apply the process where the oil viscosity significantly exceeded recognized guidelines. The pilot project consisted of four 5-acre, 5-spot patterns. Severe steam channeling became apparent within only a few months after the steamdrive was initiated. When steam channeling occurred, the available lift equipment could not lift the required volume of hot fluids. Because of the apparent reservoir heterogeneities, only half of the project producers ever experienced any appreciable response. Efforts to redirect steam flow by shutting-in the responding producers while continuing to produce the non-responding wells were successful. Throughout the early injection period, sand control problems were excessive in both the producers and injectors. Modified gravel packing procedures alleviated the problem to an extent. Significant problems were also experienced with thermal packers in the injection wells. During early life, the steam injection rate was erratic due to the downhole problems.

Four observation wells were drilled around one of the responding producers to assist in defining reservoir flow trends. Data from these wells was incorporated in a thermal simulation model. The primary conclusion of the analysis was that over-injection of steam accentuated the severe channeling which was evident in the reservoir. Wellbore heat losses were also excessive. The recommended plan of action was to cease steam injection for a period of time while the accumulated condensate in the reservoir was produced. When the condensate had been produced, steam injection would resume at lower rates to ensure that withdrawal rates exceeded injection rates. Methods of improving downhole steam quality were being evaluated.

SIGNIFICANCE OF PROJECT

Poor project performance was attributed to downhole sand control problems, severe steam channeling, and low steam quality at the sand face. Since this project was a recent vintage project, proper application of the latest technology would have reduced the severity of these problems.

STEAM FIELD PROJECT DATA SUMMARY

Project Name: El Dorado
Location: Butler County, Kansas
Operator: Cities Service
Reservoir: Admire Sand

Project Description
Size of Project: Pilot (Four 1.6-acre, 5-spot patterns)
Steam Process: Steamdrive
Process Design: Exterior water injection to contain steam within pilot area.

Reservoir Depletion at Start: Mature Secondary
Date of First Injection: 05/01/65 Date of Latest Data: 06/01/66

COMPARISON WITH NPC SCREENING CRITERIA

Parameter	NPC CRITERIA Implemented	NPC CRITERIA Advanced	Project Data	Outside Criteria
Depth, feet	3,000	5,000	650	
Net Pay, feet	20	15	17	Yes
Porosity, fraction*	0.20	0.15	0.26	
Oil Saturation x Porosity	0.10	0.08	0.10	
Permeability, millidarcy	250	10	50	Yes
Oil Gravity, °API	10-35	NL	37	Yes
Oil Viscosity, centipoise	15,000		4	
Transmissibility, (md-ft)/cP	5	NL	210	
Reservoir Pressure, psia	1,500	2,000		
Dip Angle, °	NL	NL		

*Ignored if oil saturation x porosity criteria exceeded. NL = no limitation on criteria.

Comments on exceptions to screening criteria: Reservoir thickness and the oil saturation in the start of the project were very marginal.

CONSTRAINTS ON EOR RECOVERY

(Listed in order of decreasing significance)

1. Description: Extremely low volumetric sweep (20%).
   Classification: Reservoir Heterogeneity
   Limitation: Technology

2. Description: Excessive heat loss in thin reservoir; low oil saturation at the start of the project.
   Classification: Reservoir Conditions
   Limitation: Technology

EL DORADO PROJECT
BUTLER COUNTY, KANSAS

DISCUSSION

The implementation of a steam project in the nearly depleted Admire Sand at El Dorado represented an effort to apply steam in a reservoir where conditions were known to be adverse. Prior waterflooding operations had reduced the oil saturation in the reservoir to the 40% to 50% range. In addition, high heat losses were anticipated since reservoir thickness averaged only 17 feet. Steam injection operations were conducted for about 1 year before being terminated due to lack of production response. At that time, the oil-to-steam ratio was only about 0.04 barrels of oil per barrel of steam.

Post-project analysis identified two factors responsible for failure of the steamdrive. The vertical conformance was only about 20% due to the reservoir heterogeneities. Gravity segregation did not adversely affect the volumetric sweep efficiency in the relatively thin pay zone. Unfortunately, the thin pay zone led to excessive heat losses. Analysis indicated that only about 25% of the heat injected remained in the reservoir at the end of the injection period.

SIGNIFICANCE OF PROJECT

The minimal production response observed in the El Dorado pilot test emphasizes the importance of limiting steamdrive applications to reservoirs which fall within the criteria for reservoir thickness, oil gravity, and initial oil saturation.

STEAM FIELD PROJECT DATA SUMMARY

Project Name: Georgsdorf Field
Location: Germany
Operator: BEB Bmbh
Reservoir: Sandstone
Project Description
Size of Project: Field (Three fault blocks - irregular pattern)
Steam Process: Steamdrive
Process Design: Steamdrive with supplemental steam stimulation followed by water injection for heat scavenging.
Reservoir Depletion at Start: Mature Secondary
Date of First Injection: 01/01/75 Date of Latest Data: 09/01/81

COMPARISON WITH NPC SCREENING CRITERIA

Parameter	NPC CRITERIA Implemented	NPC CRITERIA Advanced	Project Data	Outside Criteria
Depth, feet	3,000	5,000	2,500	
Net Pay, feet	20	15	125	
Porosity, fraction*	0.20	0.15	0.25	
Oil Saturation x Porosity	0.10	0.08	0.20	
Permeability, millidarcy	250	10	1,150	
Oil Gravity, °API	10-35	NL	27	
Oil Viscosity, centipoise	15,000		140	
Transmissibility, (md-ft)/cP	5	NL	1,025	
Reservoir Pressure, psia	1,500	2,000	465	
Dip Angle, °	NL	NL	14	

*Ignored if oil saturation x porosity criteria exceeded. NL = no limitation on criteria.

Comments on exceptions to screening criteria: Reservoir parameters met all of the NPC screening criteria.

CONSTRAINTS ON EOR RECOVERY

(Listed in order of decreasing significance)

1. Description: Low steam quality due to failure of gas insulation in tubing-casing annulus.
   Classification: Injectant Quality
   Limitation: Management

2. Description: H_2S/CO_2 generation from steam injection necessitated additional investment in surface facilities.
   Classification: Facility Design
   Limitation: Technology

GEORGSDORF FIELD
GERMANY

DISCUSSION

The Valanginian sandstone reservoir in the Georgsdorf field is an asymmetric anticline with a steeply dipping flank on the north. An aquifer defines the reservoir limits on three sides while a facies change limits the reservoir on one edge. Major faults divide the reservoir into essentially isolated blocks. On the flanks of the structure, edgewater drive was the primary drive mechanism while solution gas drive was predominant in the central fault blocks which were isolated from the edgewater drive by faulting. Primary recovery via these mechanisms was about 8% of the original-oil-in-place. Water and gas injection projects had increased recovery to about 13% of the original-oil-in-place when the steamdrive project was started.

Initially, steamdrive was conducted in two fault blocks using one to two upstructure injection wells per block. Temperature monitoring and production characteristics indicated that the injected steam moved upstructure while the hot, condensed steam moved downstructure. Increased production was attributed primarily to the thermal effects of the condensed steam moving downstructure.

After 6 years of steamdrive operations, a reservoir simulator was used to match production performance and to determine future operating procedures. Among other things, the simulation work detected a period of "low quality" steam injection during the project which had adversely affected production performance. From a predictive standpoint, the simulation work indicated that future infill drilling requirements were less than originally thought, that delaying steam injection in an additional block did not adversely affect overall project economics, and that drive water injection after 0.6 to 0.7 pore volumes of steam injection provided the optimum economic recovery. Ultimate project recovery with drive water injection was estimated to be 40% of the original-oil-in-place.

From an operational standpoint, two items deserve special attention. Firstly, the "low quality" steam which was injected resulted from the annulus of an injection well becoming liquid filled rather than gas filled as intended. Under these conditions, the injected steam quality decreased from 70% to 80% to 40% to 50%. Uphole casing leaks were responsible for the loss of the gas filled annulus. Secondly, hydrogen sulfide gas was generated by the reaction between the high temperature steam and the sulfur in the crude oil. As a result, unexpected investments were required in the surface facilities to protect the equipment and the environment. A similar problem was reported with hydrogen sulfide generation in the steamdrive project in the Schoonebeek field in the Netherlands.

SIGNIFICANCE OF PROJECT

The Georgsdorf project represents a field scale, steamdrive project using an irregular pattern where simulation results were used to optimize economic performance. Investment decisions related to infill drilling locations, steam volumes, and post-steam water injection were based on simulation results.

STEAM FIELD PROJECT DATA SUMMARY

Project Name: Kern River Field — Operator: Getty Oil
Location: California — Reservoir: Kern River Sand

Project Description
Size of Project: Field (Three areas - 514 total patterns)
Steam Process: Steamdrive
Process Design: Continuous steamdrive; pilot testing of foam diversion techniques.

Reservoir Depletion at Start: Mature Primary
Date of First Injection: 07/01/70 — Date of Latest Data: 10/01/77

COMPARISON WITH NPC SCREENING CRITERIA

Parameter	NPC CRITERIA Implemented	NPC CRITERIA Advanced	Project Data	Outside Criteria
Depth, feet	3,000	5,000	800	
Net Pay, feet	20	15	60	
Porosity, fraction*	0.20	0.15	0.30	
Oil Saturation x Porosity	0.10	0.08	0.15	
Permeability, millidarcy	250	10	3,000	
Oil Gravity, °API	10-35	NL	14	
Oil Viscosity, centipoise	15,000		2,000	
Transmissibility, (md-ft)/cP	5	NL	90	
Reservoir Pressure, psia	1,500	2,000	100	
Dip Angle, °	NL	NL	4	

*Ignored if oil saturation x porosity criteria exceeded. NL = no limitation on criteria.

Comments on exceptions to screening criteria: Reservoir parameters met all of the NPC screening criteria.

CONSTRAINTS ON EOR RECOVERY
(Listed in order of decreasing significance)

1. Description: Preferential steam zone flow in the upper sand.
Classification: Gravity Segregation
Limitation: Technology

KERN RIVER PROJECT
CALIFORNIA

DISCUSSION

In the early 1970s, Getty Oil implemented large-scale steamdrive projects in a portion of the Kern River field after experiencing promising recovery in pilot operations. The large-scale operations were implemented in the three expansion areas identified below. In total, 514 5-spot patterns were involved in the three areas. Operations were carefully monitored during the initial years.

Reservoir properties in the three expansion areas were as indicated below. The major differences between the expansion areas were sand thickness and oil viscosity. Saturation analysis of cores and volumetric calculations indicated that recoveries in the projects with sand thicknesses of 29 and 60 feet were approximately equal. In the project with an 80-foot sand section, recoveries were less, due to additional gravity segregation effects.

COMPARISON OF STEAM FLOOD EXPANSION AREAS

PARAMETER	EXPANSION AREA		
	Canfield	San Joaquin	G & W
Zone Thickness, feet	80	29	60
Oil Viscosity, cP	1,700	1,000	1,780
Oil Gravity, ° API	13.5	14.5	13.5
Initial Oil Saturation,%	51	52	47
Porosity, %	31	29	31
Oil Recovery, % OIP - core	53	65	64
Oil Recovery, % OIP, volume	57	78	59

Steam diversion techniques were pilot tested during the latter period of the project. A unique mechanical control method consisted of restricting production to the lower half of the sand interval after an initial period of producing from the entire interval. Intent of this procedure was to limit excessive steam channeling (wasted heat) in the upper sand interval. Limited field evaluation indicated that produced steam volumes were decreased as much as 90%. Recovery improvements could only be inferred. Steam foam treatments were evaluated in nine injectors. Tracer surveys confirmed that improved injection profiles were observed while reduced volumes of produced steam inferred the steam was staying in new zones. Results of the steam diversion tests were considered sufficiently promising to warrant further investigation.

SIGNIFICANCE OF PROJECT

The large-scale, steamdrive operations conducted by Getty Oil in the Kern River field established that high recoveries (50% to 75%) could be realized in commercial-scale projects. Pilot evaluations of steam diversion techniques also indicated that further improvements in recovery were economically feasible.

STEAM FIELD PROJECT DATA SUMMARY

Project Name: Nacatoch Sand Unit
Location: Ouachita County, AR
Operator: Phillips Petroleum
Reservoir: Nacatoch Sand

Project Description
- Size of Project: Field (Sequential development in 985-acre unit).
- Steam Process: Steamdrive
- Process Design: Steam injection in gas cap; post-steam water injection.

Reservoir Depletion at Start: Mature Primary
Date of First Injection: 11/01/64
Date of Latest Data: 04/01/81

COMPARISON WITH NPC SCREENING CRITERIA

Parameter	NPC CRITERIA Implemented	NPC CRITERIA Advanced	Project Data	Outside Criteria
Depth, feet	3,000	5,000	2,000	
Net Pay, feet	20	15	20	Yes
Porosity, fraction*	0.20	0.15	0.36	
Oil Saturation x Porosity	0.10	0.08	0.29	
Permeability, millidarcy	250	10	5,000	
Oil Gravity, °API	10-35	NL	19	
Oil Viscosity, centipoise	15,000		75	
Transmissibility, (md-ft)/cP	5	NL		
Reservoir Pressure, psia	1,500	2,000	10	
Dip Angle, °	NL	NL	5	

*Ignored if oil saturation x porosity criteria exceeded. NL = no limitation on criteria.

Comments on exceptions to screening criteria: Oil column below the gas cap ranged from 15 to 25 feet thick.

CONSTRAINTS ON EOR RECOVERY
(Listed in order of decreasing significance)

1. Description: Sand control workovers were required when heat front approached the producers.
   Classification: Downhole Completion
   Limitation: Technology

NACATOCH SAND UNIT
QUACHITA COUNTY, ARKANSAS

DISCUSSION

The steam project in the Nacatoch Sand Unit represents a novel application of thermal EOR. The reservoir in the project area consists of a 15- to 25-foot oil rim sandwiched between a gas cap and an underlying water aquifer. Reservoir pressure, which was under vacuum, at the start of the initial steam pilot in 1964 was only 5 to 10 psig. Heating of the relatively thin oil column was accomplished by injecting steam into the gas cap. The heat contained in the gas cap was primarily transferred to the oil rim by conductive heating. The higher pressure in the gas cap with steam injection also provided a larger driving force for production. Successful results in the original 22-acre pilot led to the formation of the 985-acre unit specifically for steam operations.

SIGNIFICANCE OF PROJECT

The Nacatoch Sand Unit steamdrive project represents a unique steamdrive application. A hot gas cap zone was created by injecting steam into the gas cap. Conductive heating of the underlying oil rim proved to be the major recovery mechanism.

STEAM FIELD PROJECT DATA SUMMARY

Project Name: North Midway-McKittrick
Location: California
Operator: Getty Oil
Reservoir: Potter Sand

Project Description
Size of Project: Field (10 patterns)
Steam Process: Steamdrive
Process Design: Continuous steam injection combined with steam simulation.

Reservoir Depletion at Start: Intermediate Tertiary
Date of First Injection: 01/01/64 Date of Latest Data: 07/01/81

COMPARISON WITH NPC SCREENING CRITERIA

Parameter	NPC CRITERIA Implemented	NPC CRITERIA Advanced	Project Data	Outside Criteria
Depth, feet	3,000	5,000	900	
Net Pay, feet	20	15	200	
Porosity, fraction*	0.20	0.15	0.30	
Oil Saturation x Porosity	0.10	0.08	0.15	
Permeability, millidarcy	250	10	3,000	
Oil Gravity, °API	10-35	NL	13	
Oil Viscosity, centipoise	15,000		1,380	
Transmissibility, (md-ft)/cP	5	NL		
Reservoir Pressure, psia	1,500	2,000		
Dip Angle, °	NL	NL	53	

*Ignored if oil saturation x porosity criteria exceeded. NL = no limitation on criteria.

Comments on exceptions to screening criteria: Reservoir parameters met all of the NPC screening criteria.

CONSTRAINTS ON EOR RECOVERY

(Listed in order of decreasing significance)

No constraint.

NORTH MIDWAY - McKITTRICK PROJECT
CALIFORNIA

DISCUSSION

Primary production via gravity drainage was initiated in the Potter Sand in the 1940s. From 1964 to the later 1970s, cyclic steam stimulation treatments were used to enhance oil recovery. Field practice had evolved to performing the cyclic stimulation treatments on an approximately 1-1/2-year cycle. As is typical of steam operations in thick, steeply dipping reservoirs, the highest recovery was experienced in downdip producers.

A three-dimensional thermal simulator was used to match the production performance during the cyclic steam stimulation treatments. Once an adequate history match was obtained, the simulator model was used to evaluate various available options with respect to location of additional producers and injectors, the optimum combination of steam stimulation and steamdrive, and the optimum steam injection rates. The final project design included both updip and downdip producers and injectors in a repeating, specialized pattern. Downdip injectors which were necessary to heat the lower portion of the oil column were to be converted to production after 3 to 5 years of injection. Configuration of the project without the thermal simulation results would probably have been limited to the typical, updip injection scheme.

SIGNIFICANCE OF PROJECT

The use of a thermal simulation model to design a field-scale steamdrive project in the North Midway-McKittrick project typifies the use of advancing technology to optimize economic recovery.

STEAM FIELD PROJECT DATA SUMMARY

Project Name: Ruehlertwist | Operator: Wintershall
Location: Germany | Reservoir: Sandstone

Project Description
- Size of Project: Project (One fault block - about 25 wells).
- Steam Process: Steamdrive
- Process Design: Downdip steam injection with water injection further downdip.
- Reservoir Depletion at Start: Mature Secondary
- Date of First Injection: 12/01/78 | Date of Latest Data: 03/01/83

COMPARISON WITH NPC SCREENING CRITERIA

Parameter	NPC CRITERIA Implemented	NPC CRITERIA Advanced	Project Data	Outside Criteria
Depth, feet	3,000	5,000	2,600	
Net Pay, feet	20	15	66	
Porosity, fraction*	0.20	0.15	0.28	
Oil Saturation x Porosity	0.10	0.08	0.17	
Permeability, millidarcy	250	10	2,000	
Oil Gravity, °API	10-35	NL	25	
Oil Viscosity, centipoise	15,000		175	
Transmissibility, (md-ft)/cP	5	NL	750	
Reservoir Pressure, psia	1,500	2,000	970	
Dip Angle, °	NL	NL	6	

*Ignored if oil saturation x porosity criteria exceeded. NL = no limitation on criteria.

Comments on exceptions to screening criteria: Reservoir parameters met all of the NPC screening criteria.

CONSTRAINTS ON EOR RECOVERY
(Listed in order of decreasing significance)

1. Description: Steam/hot condensate flow in upper portion of sand.
   Classification: Gravity Segregation
   Limitation: Technology

2. Description: Frequent workovers in injection/production wells due to thermal effects; problems accentuated in deviated holes.
   Classification: Downhole Completion
   Limitation: Technology

3. Description: The H_2S/CO_2 generated by the steam/crude oil interaction necessitated replacing the surface facilities.
   Classification: Facility Design
   Limitation: Technology

RUEHLERTWIST FIELD
GERMANY

DISCUSSION

The steamdrive project in the Ruehlertwist field represents a recent vintage project implemented in difficult reservoir conditions. The reservoir in the project area is an unconsolidated sandstone which exhibits significant vertical permeability variations. Permeability ranges from 300 to 10,000 millidarcies with the higher permeability zone generally located in the upper portion of the sand. In the project area, a significant edgewater drive provided sufficient energy to recover about 27% of the original-oil-in-place during primary operations. Accordingly, the target oil at the project start was lower than typically encountered in steamdrive projects.

The steamdrive process utilized downdip steam injection. Supplemental water injection at locations further downdip was used to enhance steam movement updip in this moderately dipping reservoir (6° dip angle). Extensive drilling was required to implement the project. Due to surface geology/development, most of the new wells were directionally drilled. The deviated holes required additional investment when drilled and, during steam operations, proved costly to maintain. Erratic steam injection rates which resulted from downtime in the producers and/or injectors proved to be a minor constraint on project recovery. The hydrogen sulfide generated by the steam-crude oil interaction caused additional corrosion/safety concerns which ultimately resulted in replacement of the entire oil treating facility. Proportionate operating/investment costs associated with the project were higher than encountered in most steamdrive projects.

Periodic temperature profiles in observation wells indicated that (a) the steam was moving preferentially in the upper portion of the sand, and (b) that significant heating of the overburden was occurring. Despite these inefficiencies, the cumulative and instantaneous oil-to-steam ratios after 4 years of operation were still in the 4 to 5 barrels of oil per barrel of steam range. It is surmised that thermal heating of the overriden oil coupled with the supplemental drive water injection contributed significantly to the higher than normal oil-to-steam-ratio. Incremental recovery from the steamdrive operations after 4 years of operations was 8% of the original-oil-in-place after injection of about one-third of pore volume of steam. Although project life will be extended with downdip steam injection rather than a pattern drive, the high oil-to steam ratio indicates the project is performing efficiently.

SIGNIFICANCE OF PROJECT

The Ruehlertwist steamdrive project represents a recent project where the accumulated experience from early steamdrive projects was applied. As a result, economical operations were conducted in a project which involved extensive investment in downhole and surface facilities.

STEAM FIELD PROJECT DATA SUMMARY

Project Name: Saner Ranch   Operator: Conoco
Location: Maverick County, Texas   Reservoir: Tar Sand
Project Description
Size of Project: Pilot(Single, inverted 7-spot pattern).
Steam Process: Steamdrive
Process Design: Fracture-assisted steam technology.
Reservoir Depletion at Start: Virgin Reservoir
Date of First Injection: 03/01/81   Date of Latest Data: 01/01/83

COMPARISON WITH NPC SCREENING CRITERIA

Parameter	NPC CRITERIA Implemented	Advanced	Project Data	Outside Criteria
Depth, feet	3,000	5,000	1,400	
Net Pay, feet	20	15	65	
Porosity, fraction*	0.20	0.15	0.28	
Oil Saturation x Porosity	0.10	0.08	0.15	
Permeability, millidarcy	250	10	750	
Oil Gravity, °API	10-35	NL	2	
Oil Viscosity, centipoise	15,000		2,000,000	Yes
Transmissibility, (md-ft)/cP	5	NL		
Reservoir Pressure, psia	1,500	2,000		
Dip Angle, °	NL	NL	2	

*Ignored if oil saturation x porosity criteria exceeded. NL = no limitation on criteria.

Comments on exceptions to screening criteria: Tar is immobile at reservoir conditions.

CONSTRAINTS ON EOR RECOVERY

(Listed in order of decreasing significance)

1. Description: Induced fractures were required to achieve injectivity with the low mobility of the oil at reservoir conditions.
   Classification: Reservoir Conditions
   Limitation: Technology

SANER RANCH PROJECT
MAVERICK COUNTY, TEXAS

DISCUSSION

Oil recovery during the Sanar Ranch pilot test was about 47% of the original-oil-in-place. To realize recovery of this magnitude in a tar reservoir where native viscosity approached 2,000,000 cP, Conoco used their fracture-assisted steamflood technology (FAST). The FAST process had previously been tested in another portion of the field. The cumulative oil-to-steam ratio during the project was about 0.12 barrels of oil per barrel of steam - ratios in this range have been observed in steamdrives in significantly less viscous, heavy oil reservoirs.

The FAST process utilizes four distinct phases to achieve recovery of this magnitude with the given reservoir conditions. Initially, specialized procedures are used to create horizontal fractures in the producers. The effective wellbore size of the producers is then increased via steam stimulation. After the producers have been stimulated, the central injector is notched to create a horizontal fracture. Steam is then intentionally injected at high rates. The intent of this phase is to quickly establish heat and fluid communication between the injector and the producers. The third phase consists of injecting steam at a lower rate over the entire interval. Efforts are made to provide heat to the matrix during this phase. Heated tar from the matrix then flows into the high conductivity fracture channels from which it is produced. As a final step, hot water is injected to recover any remaining tar which was mobilized by the steam process. About 22% of the tar recovered during the project was attributed to the water injection phase.

SIGNIFICANCE OF PROJECT

The fracture-assisted steamflood technology (FAST) used in the Saner Ranch pilot represents a significant advance in steamflood technology for reservoirs with very high oil viscosities.

STEAM FIELD PROJECT DATA SUMMARY

Project Name: Shiells Canyon
Location: Ventura County, California
Operator: Texaco
Reservoir: Tar Sand

Project Description
- Size of Project: Pilot(Two injectors; 13 producers).
- Steam Process: Steamdrive
- Process Design: Updip steam injection.
- Reservoir Depletion at Start: Mature Primary
- Date of First Injection: 03/01/73
- Date of Latest Data: 07/01/77

COMPARISON WITH NPC SCREENING CRITERIA

Parameter	NPC CRITERIA Implemented	NPC CRITERIA Advanced	Project Data	Outside Criteria
Depth, feet	3,000	5,000	850	
Net Pay, feet	20	15	140	
Porosity, fraction*	0.20	0.15	0.21	
Oil Saturation x Porosity	0.10	0.08	0.09	Yes
Permeability, millidarcy	250	10	140	Yes
Oil Gravity, °API	10-35	NL	34	
Oil Viscosity, centipoise	15,000		6	
Transmissibility, (md-ft)/cP	5	NL	3,250	
Reservoir Pressure, psia	1,500	2,000	85	
Dip Angle, °	NL	NL	35	

*Ignored if oil saturation x porosity criteria exceeded. NL = no limitation on criteria.

Comments on exceptions to screening criteria: Gravity drainage in the steeply dipping reservoir offset the other marginal reservoir parameters.

CONSTRAINTS ON EOR RECOVERY

(Listed in order of decreasing significance)

No constraint.

SHIELLS CANYON PROJECT

DISCUSSION

Updip steam injection was used in the Shiells Canyon project to maximize gravity drainage effects. At the time of the project, primary recovery in the steeply dipping (35°), light oil reservoir was about 10% of the original-oil-in-place. Steam distillation represented a primary recovery mechanism during the steamflood operations. Laboratory testing indicated that 54% of the crude was distillable under steamflood conditions. Analysis of core data from an area which had been subjected to extensive steam injection indicated that the residual oil saturation had been reduced from 45% to about 3%. The average oil-to-steam ratio in the project after about 6 years of operation was 0.25 - a ratio higher than that experienced in many steamdrives.

Special procedures were required to maintain steam injectivity since the reservoir contained large quantities of water sensitive clays. Potassium chloride treatments were used to reduce clay swelling. At the start of injection, the injection wells were treated with a slug of potassium chloride solution. Small amounts of potassium chloride solution were then injected continuously.

SIGNIFICANCE OF PROJECT

The use of potassium chloride solution to condition the reservoir clays and prevent reduced steam injectivity illustrates how the relatively straightforward steam injection process must be tailored for individual reservoir conditions.

STEAM FIELD PROJECT DATA SUMMARY

Project Name: Schoonebeek — Operator: Shell Oil
Location: Netherlands — Reservoir: Sandstone

Project Description
- Size of Project: Pilot (80 acres - 4 patterns).
- Steam Process: Steamdrive
- Process Design: Steam soaks on selected producers were unsuccessful due to mechanical problems.
- Reservoir Depletion at Start: Mature Primary
- Date of First Injection: 09/01/60 — Date of Latest Data: 04/01/67

COMPARISON WITH NPC SCREENING CRITERIA

Parameter	NPC CRITERIA Implemented	NPC CRITERIA Advanced	Project Data	Outside Criteria
Depth, feet	3,000	5,000	2,500	
Net Pay, feet	20	15	80	
Porosity, fraction*	0.20	0.15	0.30	
Oil Saturation x Porosity	0.10	0.08	0.26	
Permeability, millidarcy	250	10	5,000	
Oil Gravity, °API	10-35	NL	21	
Oil Viscosity, centipoise	15,000		170	
Transmissibility, (md-ft)/cP	5	NL	2,350	
Reservoir Pressure, psia	1,500	2,000	120	
Dip Angle, °	NL	NL	8	

*Ignored if oil saturation x porosity criteria exceeded. NL = no limitation on criteria.

Comments on exceptions to screening criteria: The oil is relatively nonviscous when compare to many thermal projects.

CONSTRAINTS ON EOR RECOVERY

(Listed in order of decreasing significance)

1. Description: Steam flow only in upper one-third of reservoir - gravity segregation aggravated by 10:1 permeability variation.
   Classification: Gravity Segregation
   Limitation: Technology

2. Description: Production response only in a portion of producers.
   Classification: Reservoir Heterogeneity
   Limitation: Technology

3. Description: Scale plugging of injectors from CO_2-laden gas in the tubing-casting annulus.
Classification: Injectant Quality
Limitation: Management

SCHOONEBEEK FIELD
NETHERLANDS

DISCUSSION

The steamdrive project was initiated in a portion of the field where primary production via solution gas drive had produced about 4% of the original-oil-in-place. As a result of the solution gas drive process, a free gas saturation had developed in the single, unconsolidated sand body. Initial steam injection rates were quite high until fill-up occurred. After fill-up, relatively stable steam injection rates were experienced. To maintain stable injection rates, routine acid jobs were required in the injection wells to remove calcium carbonate scale which was being formed on the exterior of the tubing and flaking off the plug the formation face. The scale was forming in the tubing-casing annulus when the CO_2-laden injection gas in the annulus contacted small amounts of water. Calcium carbonate scale was precipitated under the high temperature conditions.

Even though the formation was only moderately dipping, process monitoring indicated the steam zone was preferentially moving updip. the bulk of oil and water production was being realized in downdip producers. Areal heterogeneities apparently influenced project performance since some producers had not responded to steam injection after 6 years. Project monitoring indicated that the steam was flowing only in the upper third of the pay zone. Core saturations, temperatures profiles, and simulation results were used to define the extent of gravity segregation which was occurring. In this instance, the natural tendencies for gravity segregation were accentuated by permeability stratification - permeability in the upper portion of the pay was as much as 10 times higher than that in the lower portion of the pay. Despite these adverse conditions, incremental recovery in the project was sufficient to warrant expansion to other areas.

SIGNIFICANCE OF PROJECT

The economically successful steamdrive in the Schoonebeek field demonstrates that thermal enhanced oil recovery can be practical, even when extremely low volumetric sweep efficiencies are experienced. High displacement efficiencies and generally high oil saturations at floodstart provide a margin of error for process inefficiencies.

STEAM FIELD PROJECT DATA SUMMARY

Project Name: Ten Pattern Steamflood
Location: California
Operator: Chevron
Reservoir: Kern River Sand
Project Description
Size of Project: Pilot (61 acres - 10 inverted 7-spot patterns).
Steam Process: Steamdrive
Process Design: Initial steam stimulation followed by steamdrive; post-steam waterflooding after 10 years.
Reservoir Depletion at Start: Mature Primary
Date of First Injection: 10/01/68
Date of Latest Data: 08/01/79

COMPARISON WITH NPC SCREENING CRITERIA

Parameter	NPC CRITERIA Implemented	NPC CRITERIA Advanced	Project Data	Outside Criteria
Depth, feet	3,000	5,000	750	
Net Pay, feet	20	15	97	
Porosity, fraction*	0.20	0.15	0.35	
Oil Saturation x Porosity	0.10	0.08	0.18	
Permeability, millidarcy	250	10	7,600	
Oil Gravity, °API	10-35	NL	14	
Oil Viscosity, centipoise	15,000		2,710	
Transmissibility, (md-ft)/cP	5	NL	60	
Reservoir Pressure, psia	1,500	2,000	120	
Dip Angle, °	NL	NL	310	

*Ignored if oil saturation x porosity criteria exceeded. NL = no limitation on criteria.

Comments on exceptions to screening criteria: Reservoirs parameters met all of the NPC screening criteria.

CONSTRAINTS ON EOR RECOVERY

(Listed in order of decreasing significance)

1. Description: Preferential steam flow in the upper sand zone.
   Classification: Gravity Segregation
   Limitation: Technology

2. Description: Heat front arrival time varied from 2 weeks to 2 years.
   Classification: Reservoir Heterogeneity
   Limitation: Technology

TEN PATTERN STEAMFLOOD CALIFORNIA

DISCUSSION

The Ten Pattern Steamflood was conducted in the lower sand in the Kern River sand series. Extensive well work was required prior to steam injection in this field because initial primary development had occurred in the 1915 time period. Existing Producers were reworked to install new slotted liners for sand control. All of the injectors were newly drilled and cased through the sand interval. Producers were completed in several sand intervals while the injectors were completed in, what was later discovered to be, the middle of the sand.

Steam stimulation treatments were performed in all of the producers at the start of the project. Since the injectors were not initially stimulated with steam, initial injection pressures were as high as 620 psig. Injection pressures decreased to about 200 psig as the near wellbore region became hot and oil was displaced further into the reservoir. Project performance was monitored with periodic temperature profiles in observation wells and with oil saturation measurements in core samples. Comparison of field results with various theoretical heat models for steam operations assisted in understanding the behavior of the steamdrive in the reservoir.

The overall volumetric sweep efficiency of the steam zone and the hot water zone was about 60%. Displacement efficiency in the steam zone, which comprised only the upper third of the sand due to gravity segregation, was about 87%. Although the steam zone only contacted the upper portion of the reservoir, a hot water zone below the steam zone contacted most of the remaining sand section. Displacement efficiency in the hot water zone was about 52%. Areal sweep in the hot water zone was 77% versus 56% in the higher mobility steam zone. Major heterogeneities were apparent in the project since the time for the heat front to arrive at observation wells located equidistant from an injection well varied from 2 weeks to 2 years. Both the cumulative and instantaneous oil-to-steam ratios after 8 to 10 years of injection were in the range of 0.15 to 0.20 barrels of oil per barrel of steam. During this period, total oil recovery was about 20% of the original-oil-in-place, whereas previous primary operations had recovered only 13% of the original-oil-in-place in about 70 years.

Post-steam water injection was used to scavenge heat and maintain reservoir pressure after steam injection was stopped. Current ultimate recovery is estimated at about 70% of the original-oil-in-place with about 15% attributed to the post-steam water injection. Interestingly, temperature monitoring during the water injection phase indicated that the water injection did not follow the same path as the steam.

SIGNIFICANCE OF PROJECT

The estimated ultimate recovery of 70% of the original-oil-in-place in the project area illustrates the high recoveries which can be experienced when thermal EOR operations are optimized. Post-steam water injection contributed about one-fifth of the total project recovery.

STEAM FIELD PROJECT DATA SUMMARY

Project Name: Tia Juana Field
Location: Venezuela
Operator: Shell Oil
Reservoir: Miocene Sand

Project Description
Size of Project: Field (7 hexagonal patterns with central injection wells).
Steam Process: Steamdrive
Process Design: Separate injectors for upper and lower zones; steam stimulation of peripheral wells in mid-life.
Reservoir Depletion at Start: Intermediate Primary
Date of First Injection: 9/01/61 Date of Latest Data: 01/01/67

COMPARISON WITH NPC SCREENING CRITERIA

Parameter	NPC CRITERIA Implemented	NPC CRITERIA Advanced	Project Data	Outside Criteria
Depth, feet	3,000	5,000	1,600	
Net Pay, feet	20	15	200	
Porosity, fraction*	0.20	0.15	0.33	
Oil Saturation x Porosity	0.10	0.08	0.25	
Permeability, millidarcy	250	10	2,000	
Oil Gravity, °API	10-35	NL	11	
Oil Viscosity, centipoise	15,000		4,000	
Transmissibility, (md-ft)/cP	5	NL	100	
Reservoir Pressure, psia	1,500	2,000	1,000	
Dip Angle, °	NL	NL	3	

*Ignored if oil saturation x porosity criteria exceeded. NL = no limitation on criteria.

Comments on exceptions to screening criteria: Reservoirs parameters met all of the NPC screening criteria.

CONSTRAINTS ON EOR RECOVERY
(Listed in order of decreasing significance)

1. Description: Segregated flow within both the upper and lower zones.
   Classification: Gravity Segregation
   Limitation: Technology

2. Description: 21 Liner failures - subsidence related.
   Classification: Downhole Completion
   Limitation: Technology

TIA JUANA FIELD
VENEZUELA

DISCUSSION

Production and reservoir characteristics in the steamdrive project area in the Tia Juana field were similar to those in the offsetting steam stimulation project. Primary production of about 12.5% of the original-oil-in-place had been realized via a compaction drive mechanism. The reservoir in the project area consisted of an upper and lower zone of about 100 feet thickness each with about 90 feet of separation between the zones. As in the steam stimulation project, pressure in the lower zone was significantly higher than in the upper zone. Since uneven steam distribution between the zones was a major problem in the steam stimulation project, separate injectors were provided for the two zones in the steamdrive project. Producers were completed in both zones.

The steamdrive project used a hexagonal pattern with some new producers drilled within the hexagonal pattern. Although the separate injectors for each zone ensured steam was entering each zone, early spinner surveys indicated significant gravity segregation was occurring within each zone. Steam stimulation treatments were performed on selected, unresponsive producers to promote more uniform steam flow in the reservoir.

The cumulative oil-to-steam ratio experienced in the steamdrive after about 4 years of operation was about 0.6 barrels of oil per barrel of steam - significantly lower than with the steam stimulation project. Although the oil-to-steam ratio was less favorable, ultimate project recovery from primary and steamdrive was estimated at about 38% of the original-oil-in-place - about 8% higher than with the steam stimulation project. Expansion to a large scale steamdrive project was delayed due to (a) the less favorable oil-to-steam ratios, and (b) the advantages of implementing steam operations in late-life when compaction represents the major primary recovery mechanism.

SIGNIFICANCE OF PROJECT

The decision to continue steam stimulation operations while deferring steamdrive operations in the Tia Juana field illustrates the controlling influence of steam utilization - barrels of oil per barrel of steam - on project economics. Although higher total recovery was experienced with steamdrive, the oil-to-steam ratio with steam stimulation operations was much more favorable.

STEAM FIELD PROJECT DATA SUMMARY

Project Name: Tia Juana Field   Operator: Shell Oil
Location: Venezuela   Reservoir: Miocene Sand
Project Description
Size of Project: Field (850 acres).
Steam Process: Steamdrive
Process Design: Cyclic stimulation on approximately 1-year cycle; pilot test of steam foam.
Reservoir Depletion at Start: Intermediate Primary
Date of First Injection: 3/01/64   Date of Latest Data: 01/01/67

COMPARISON WITH NPC SCREENING CRITERIA

Parameter	NPC CRITERIA Implemented	NPC CRITERIA Advanced	Project Data	Outside Criteria
Depth, feet	3,000	5,000	1,750	
Net Pay, feet	20	15	177	
Porosity, fraction*	0.20	0.15	0.40	
Oil Saturation x Porosity	0.10	0.08	0.32	
Permeability, millidarcy	250	10	2,000	
Oil Gravity, °API	10-35	NL	13	
Oil Viscosity, centipoise	15,000		700-7,000	
Transmissibility, (md-ft)/cP	5	NL	85	
Reservoir Pressure, psia	1,500	2,000	780	
Dip Angle, °	NL	NL		

*Ignored if oil saturation x porosity criteria exceeded. NL = no limitation on criteria.

Comments on exceptions to screening criteria: Reservoirs parameters met all of the NPC screening criteria.

CONSTRAINTS ON EOR RECOVERY

(Listed in order of decreasing significance)

1. Description: Unequal steam distribution between upper and lower sands.
   Classification: Reservoir Heterogeneity
   Limitation: Technology

2. Description: 21 Liner failures - subsidence related.
   Classification: Downhole Completion
   Limitation: Technology

TIA JUANA FIELD
VENEZUELA

DISCUSSION

The reservoir in the project area consists of an upper and lower sand interval of about 100 feet thickness each separated by an noncommunicating interval of varying thickness. The major production mechanism during primary production was compaction or reservoir subsidence. At the time of the steam project, primary production was about 12.5% of the original-oil-in-place. Ultimate recovery with continued primary production was estimated at about 18% of the original-oil-in-place. During the primary production phase, the reservoir pressure in the upper zone had fallen considerably below that in the lower zone due to higher viscosity in the lower zone.

Project injection wells were completed open-hole using slotted liners. Initially, no effort was made to control the amount of the injected steam entering the upper and lower zones. When early injection indicated that steam was preferentially entering the upper zone, attempts were made to mechanically control steam entry. Providing the noncommunicating interval between the sands was sufficiently thick, experience indicated that setting a packer in the blank liner between the zones was effective.

In the project, 73 steam stimulation treatments were performed in a 3-year period. For some producers, three cycles were conducted. The average oil-to-steam ratio during the first 3 years was about 3 barrels of oil per barrel of steam. Oil production during the 3-year period was equivalent to about 20 years of continued primary production. During this 3-year period, total oil recovery increased from 12.5% of the original-oil-in-place to about 24% of the original-oil-in-place. Ultimate total recovery was estimated to be 30% of the original-oil-in-place. The major operational problem reported during the project was liner failures occurred in areas of high subsidence.

From a process standpoint, the primary constraint on oil recovery was the poor steam injection profiles. Pilot tests conducted at a later date on five wells indicated that steam diverted, on the average, about one-third of the steam to new intervals. Since long-term foam stability was not a concern with short-term injection periods during steam stimulation, steam diversion during the injection period was the primary evaluation criteria. Although the foam treatments improved the injection profiles, increased water cuts was experienced during the production phase - 90% water cut versus 30% to 60% with injection of steam only. The higher water cut partially offset the economic advantages of the improved injection profiles. Results with the foam were considered sufficiently promising to warrant further evaluation.

SIGNIFICANCE OF PROJECT

The steam foam diversion techniques in the Shell-Maraven project in the Tia Juana field represent a successful application of new technology in an early vintage project. The steam foams addressed the reservoir heterogeneities which dominated steam-only operations.

STEAM FIELD PROJECT DATA SUMMARY

Project Name: Winkleman Dome Field
Location: Fremont County, Wyoming
Operator: Amoco
Reservoir: Nugget Sand
Project Description
Size of Project: Field (14 patterns in four expansion phases)
Steam Process: Steamdrive
Process Design: Continuous steam injection; supplemental steam stimulation was found to be uneconomic.
Reservoir Depletion at Start: Intermediate Primary
Date of First Injection: 3/01/64
Date of Latest Data: 07/01/75

COMPARISON WITH NPC SCREENING CRITERIA

Parameter	NPC CRITERIA Implemented	NPC CRITERIA Advanced	Project Data	Outside Criteria
Depth, feet	3,000	5,000	1,220	
Net Pay, feet	20	15	57	
Porosity, fraction*	0.20	0.15	0.24	
Oil Saturation x Porosity	0.10	0.08	0.18	
Permeability, millidarcy	250	10	500	
Oil Gravity, °API	10-35	NL	14	
Oil Viscosity, centipoise	15,000		900	
Transmissibility, (md-ft)/cP	5	NL	32	
Reservoir Pressure, psia	1,500	2,000	210	
Dip Angle, °	NL	NL	25	

*Ignored if oil saturation x porosity criteria exceeded. NL = no limitation on criteria.

Comments on exceptions to screening criteria: Reservoirs parameters met all of the NPC screening criteria.

CONSTRAINTS ON EOR RECOVERY
(Listed in order of decreasing significance)

1. Description: Steam flow only in upper portion of sand.
   Classification: Gravity Segregation
   Limitation: Technology

2. Description: Faults, channels, directional permeability trends.
   Classification: Reservoir Heterogeneity
   Limitation: Technology

WINKLEMAN DOME FIELD
FREMONT COUNTY, WYOMING

DISCUSSION

The Nugget reservoir in the Winkleman Dome field is a relatively steep dipping (25°) anticlinal structure. The reservoir exhibits a high degree of permeability stratification. Three distinct zones with a degree of separation are evident. Ultimate primary production via water influx was estimated at about 8% of the original-oil-in-place. The initial steamdrive operation consisted of a 40-acre 5-spot pattern with an infill observation well and an offset 10-acre, 5-spot pattern. Production response in the 10-acre pattern within the first 3 years was sufficiently promising that four expansions were conducted within the next 10 years. Recovery as of the latest data available was about 17% of the original-oil-in-place.

Project monitoring revealed that steam flow occurred only in a thin zone at the very top of pay zone. Despite the poor sweep efficiency of the steam zone, conductive heating of the underlying oil zone contributed significantly to production response. Additional reservoir heterogeneities like fault isolation, permeability channels, and directional permeability trends were also evident during the expansion phases of the steamdrive. Despite these adverse conditions, economic recovery was realized in the project.

SIGNIFICANCE OF PROJECT

Although severe gravity segregation occurred, the incremental recovery via heating of the overridden oil was sufficient to overcome the adverse effects of gravity segregation and reservoir heterogeneities.

STEAM FIELD PROJECT DATA SUMMARY

Project Name: Yorba Linda Field
Location: California
Operator: Shell Oil
Reservoir: Conglomerate
Project Description
Size of Project: Pilot (Phase I + two expansions)
Steam Process: Steamdrive
Process Design: Steamdrive with supplemental steam stimulation of producers.
Reservoir Depletion at Start: Mature Primary
Date of First Injection: 09/01/71 Date of Latest Data: 01/01/75

COMPARISON WITH NPC SCREENING CRITERIA

Parameter	NPC CRITERIA Implemented	NPC CRITERIA Advanced	Project Data	Outside Criteria
Depth, feet	3,000	5,000	650	
Net Pay, feet	20	15	325	
Porosity, fraction*	0.20	0.15	0.30	
Oil Saturation x Porosity	0.10	0.08	0.14	
Permeability, millidarcy	250	10	600	
Oil Gravity, °API	10-35	NL	14	
Oil Viscosity, centipoise	15,000		6,400	
Transmissibility, (md-ft)/cP	5	NL	30	
Reservoir Pressure, psia	1,500	2,000		
Dip Angle, °	NL	NL	12	

*Ignored if oil saturation x porosity criteria exceeded. NL = no limitation on criteria.

Comments on exceptions to screening criteria: Reservoirs parameters met all of the NPC screening criteria.

CONSTRAINTS ON EOR RECOVERY

(Listed in order of decreasing significance)

1. Description: Uneven heat flow in reservoir due to silt layers.
   Classification: Reservoir Heterogeneity
   Limitation: Technology

YORBA LINDA FIELD
CALIFORNIA

DICUSSION

The Conglomerate zone in the Yorba Linda field consists of a mixture of silts, sands, and conglomerates. The lenticular, discontinuous silt layers of up to 100 feet in thickness create localized regions of restricted vertical permeability. Silt content through the field ranges from 10% to 50%. Initial steam stimulation treatments in the field increased recovery from 5% of the original-oil-in-place under primary to about 35% of the original-oil-in-place. Later pilot tests with conversion from steam stimulation to steamdrive at an optimum time further increased recovery to 45% to 55% of the original-oil-in-place.

During these initial steam projects, it became apparent that separate steam banks were forming under the silt barriers. Horizontal steam movement under the barriers was much rapid than in areas of the field where the barriers did not exist. As a result, the producers in areas with silt barrier often experienced steam channeling and, because less oil column was being heated, lower production response. Since the silt barriers were discontinuous, the steam which was trapped under the silt barriers would move vertically wherever a gap in the barrier was present. Oil recovery in areas where barriers were not present was higher because a thicker oil column was being heated.

The Phase I pilot consisted of four injectors completed just below a silt barrier. In one direction, the offset producers also encountered the barrier. Rapid, horizontal steam movement below the silt barrier caused steam breakthrough unless the producers were completed very low in the sand interval below the silt barrier. Offset producers in the other direction did not encounter the silt barrier. A thick oil column was heated by the primarily vertical steam movement. Frequent steam stimulation treatments were required in this area to remove the cold oil bank from around the producers so that the large, heated oil column could be produced. Economic steamdrive operations were conducted in both areas by matching the completion and operating procedures to the reservoir environment. Subsequent expansions were conducted in areas with and without the silt barriers.

SIGNIFICANCE OF PROJECT

Specialized completion and operating procedures which considered the influence of known reservoir heterogeneities enabled economic steamdrive operations to be conducted in areas with and without interspersed silt barriers.

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