# NEW DEVELOPMENTS IN THE EXTRACTION OF OIL

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There are three main areas of interest concerned with new developments in extraction of oil. These are improved engineering techniques, new reservoir recovery methods and developments in the extraction of oil from oil shale and tar sands.

The most powerful and universal reservoir engineering calculation technique is numerical mathematical reservoir simulation which has come into general use over the past five years. Reservoir simulation techniques have enabled the petroleum industry to determine the optimum locations to drill wells and the best way to produce a field to get the most oil for the least cost.

New recovery methods can be considered to lie in three categories: improved waterflooding approaches, miscible displacement techniques and thermal recovery methods. Two types of improved water floods, polymer displacements and micellar floods, may be applicable to a number of oil reservoirs as the price of oil increases. Miscible flooding techniques are economically successful under special conditions. The use of hydrocarbon miscible processes in the U.S. would not seem to become more applicable as the price of oil increases because the price of gas will probably increase more rapidly. The thermal processes of forward combustion and steam soak have been tried extensively. There are few economic forward combustion projects, however, this process is expected to be more applicable as the price of oil increases. The steam soak process has proven quite successful in California where it was credited with a production of 140M BOPD in 1968.

Total Athabaska Oil Sands and Oil Shale resources are estimated at 600 billion and 1780 billion barrels of oil, respectively. The Great Canadian Oil Sands, Ltd. project, the first commercial large scale operation in tar sand, was started in 1968 at a design capacity of 45M BOPD. Currently, it is operating at 50M BOPD and is said to be on a break-even basis. Construction of a second tar sands extraction plant by Syncrude Canada, Ltd. with a capacity of 125M BOPD is scheduled to begin in 1973. Colony Development Corporation shut down operation in its 1000 tons per day shale oil extraction plant during May of this year. They are now evaluating the commercial feasibility of building a 50M BOPD plant to go on stream in 1977. It is estimated that by 1985 oil production from tar sands and oil shale could reach 1000M and 750M BOPD, respectively.

## INTRODUCTION

I would like to cover three principal areas where new developments in oil extraction technology have increased the oil reserves in North America and/or hold the potential of increasing these reserves many fold in the future. These areas are: (1) advances in reservoir engineering whereby oil and gas reservoirs can be exploited more efficiently through improved control, (2) development of new and improved secondary and tertiary recovery mechanisms so that previously unrecoverable oil can be economically recovered, and (3) development of processes to economically recover oil from sources other than the traditional oil reserves.

The average recovery efficiency from oil reservoirs has increased from 22 percent in 1942 to 31 percent of the oil in place in 1971. The development of the science of reservoir engineering which involves the understanding of reservoirs and methods to optimize their exploitation has largely been responsible for this increase. Water displacement of oil from reservoirs has been the principal displacement mechanism used to recover oil economically after oil has been produced by its primary producing mechanism. The application of new secondary and tertiary recovery techniques will increase the average recovery efficiency to 37 percent of the oil in place by 1985 if the National Petroleum Council's predictions are correct. Also, by 1985 it is estimated the production of oil from oil shale and tar sands could reach 750M BOPD and 1000M BOPD, respectively.

## IMPROVED RESERVOIR CONTROL

There have been many techniques and formulas developed over the years to enable engineers to better test, evaluate and control reservoirs, thereby exploiting them more efficiently. This body of knowledge comprises the science of reservoir engineering. The advent of the computer has enabled the development of the most powerful and universal reservoir engineering calculation technique yet devised. This technique is numerical mathematical reservoir simulation.

Mathematical reservoir simulation, as its name implies, is the technique of matching a reservoir's past behavior so that its future behavior under various controlled circumstances can be predicted. In this matter, the simulation can be used to determine the optimum locations to drill wells and the best way to produce the field to get the most oil for the least cost.

Mathematical reservoir modeling had its early beginning in the late 1950's. The classic paper by Douglas, Peaceman and Rachford[1] in 1958 outlined the basic equations (that represented three phase flow in porous media) and boundary conditions to be solved numerically.

The use of numerical simulation models to solve applied reservoir problems increased as computers became larger and faster. In the early 1960's, their use was primarily restricted to large petroleum company laboratories. By 1965, consulting companies were offering the reservoir simulation study service. Models were offered for sale about the same time.

These models were relatively slow. Because of this and because of computer size limitations, they were restricted to one or two dimensions. During the past five years, reservoir modeling has become a standard tool for most competent reservoir engineers. Models are now available to study reservoir behavior in three dimensions, the well bore performance in radial geometry and the behavior of volatile oil and condensate systems. The computer costs have been reduced drastically and now some reservoir evaluations can be made for a few hundred dollars of computer time. In the past, the cost of three dimensional studies was prohibitive but now can be justified for many large oil reservoirs.

Results obtained by using mathematical numerical simulation to study an oil reservoir can be only as good as the input information. The old phrase "garbage in - garbage out" applies, however, when these tools are used by reservoir engineers who understand modeling and the science of reservoir mechanics, they are invaluable. Earlier reservoir calculation procedures were likewise dependent on the reservoir data used and were also subjected to many limiting assumptions concerning the boundary conditions and the coefficients of the equations describing fluid flow. A reservoir simulation is only restricted by non-representative input data or improper original description of the reservoir.

Reservoir models can be used not only to predict the performance of a newly discovered reservoir but they can be used to predict the results that various secondary recovery procedures might have. The science of reservoir modeling is still being developed to predict the behavior of such exotic new recovery methods as miscible displacement and thermal recovery processes.

## NEW RECOVERY METHODS

### Improved Water Flood Techniques

A number of improved water flooding techniques have been devised in the laboratory. These include: water driven alcohol slug displacement, water driven foam flood, miscellar flood, water driven LPG surfactant flood, polymer flood, the Orco process, simultaneous gaswater flood, etc. Several of these processes have been pil[illegible] the field, but only the micellar and polymer flooding concepts appear to have a chance to become economic (as the price of oil increases) for a significant number of reservoirs. All of the processes mentioned above were conceived to increase the oil recovery over that of conventional waterflooding.

### Polymer Flooding

When an oil reservoir is "waterflooded," water is injected into certain wells and it travels through the reservoir "banking up" and pushing out oil into the producing wells. The oil displacement efficiency of water flooding is primarily dependent upon the viscosity ratio of the oil to water. As the viscosity ratio becomes greater the displacement efficiency becomes less for the same quantity of water injected. As oil viscosities increase, conventional waterflooding becomes much less efficient and at some oil viscosity the waterflood fails economically. Very few waterfloods are economic in reservoirs containing oil over 30 cp.

Certain, highly soluble, partially hydrolyzed polyacrylamides (polymers) can be used as apparent viscosity increasing agents. If 300 to 500 ppm of polymer is added to water, the viscosity of the polymer solution will be increased from one to three cp or more. However, the "apparent" viscosity or mobility of this solution as it travels through porous media may be 10 cp or more. Therefore, if we displace a 10 cp oil with a 10 cp polymer solution the resulting ratio is only one, and the displacement efficiency will be equivalent to a conventional waterflood displacing a one cp oil. Therefore, the addition of polymers permits the efficient displacement of oil up to the 100 to 150 cp range.

Polymers are costly and, therefore, "slugs" of polymer solution equal to 25 percent of the volume of the reservoir or more are injected, followed by water. In this manner, polymer costs are reduced with only some sacrifice in displacement efficiency. Polymer absorption on reservoir rock surfaces can be a prohibitively expensive problem. Polymer injection can theoretically improve oil recovery, perhaps by 50 percent after one pore volume injection.[2] However, the added investment for polymer early in the project life may in many cases offset the economic benefits of earlier oil recovery.

In 1970 Jewett and Sehurg listed 61 polymer flood projects that had been started between 1964 and 1969 using Dow Chemical polymers.[3] These represented 95 percent of those that had been started. Half of them were listed as unsuccessful either because of too small slug size, too viscous oil, fractured reservoir, tertiary recovery project, reservoir underlain by water, etc. Most of them were listed as too early to tell the final outcome, however, eight tests were listed as successful because of being sustained by published paper or the tests had been expanded to commercial size. Bleakley's incomplete survey in 1971 indicated that most polymer floods had not been fully evaluated and apparently more time will be needed to determine profitability.[4]

The determination of incremental oil attributable to a polymer displacement over a water flood can only be estimated theoretically. There is no way to quantitatively determine this increment from a field pilot test. Nevertheless, there are probably some reservoirs where polymer flooding could be profitable at today's oil prices and there should be an increasing number of such cases in the future as oil prices increase.

### Micellar Flooding

Micellar flooding is a relatively new improved waterflood process that can be used for both secondary and tertiary conditions. Micellar solutions, also known as microemulsions, can be driven through a reservoir by water, displacing 100 percent of the oil in that part of the reservoir that is contacted. These solutions are composed of surfactant, hydrocarbon and water and are stable in the presence of reservoir water and rock. Micellar solutions may also contain small amounts of electrolytes and cosurfactants such as alcohol. The specific reservoir application determines the type and concentration of each component. The viscosity of these solutions can be controlled, however, a mobility buffer (a polymer solution) is injected behind the micellar solution and ahead of the displacing water so that the water does not contact the micellar solution.

Bleakley lists 11 field tests of the micellar (Maraflood) process, five of these have been completed in Illinois and two in Pennsylvania.[5] These tests show that 50 percent of the oil remaining after waterflooding can be recovered by using a micellar slug size of four to six percent of a pore volume.

Present micellar slug costs are about $6 per barrel but are estimated to ultimately reduce to $3.40.[6] Polymer costs are estimated at 29 cents per barrel. Using these projected costs, a tertiary reservoir having only 50 percent oil saturation would yield recoverable oil for $2.50 per barrel. The micellar displacement concept may be economically applicable to a number of abandoned oil reservoirs when micellar costs are further reduced and the price of oil increases.

### Miscible Drive Displacement Techniques

Several miscible displacement techniques have been tested in field projects. These include high pressure dry gas displacements, enriched gas displacements, water driven LPG slug displacements and water driven carbon dioxide displacements. All appear to be economically successful under special conditions. Bleakley lists some 20 projects at this time with most of them reported to be economically successful or promising.[4]

### High Pressure Natural Gas Displacement

The high pressure natural gas displacement process involves the injection of natural gas (mostly methane) at a sufficiently high pressure, so that as it travels through the reservoir and is enriched by the light components of the reservoir crude oil, it soon becomes miscible with newly encountered reservoir fluid. In this manner, under the continuous injection of dry gas, the reservoir crude oil that is contacted (in the swept region) can be completely displaced from the reservoir. This process and the enriched gas process are what are called conditionally miscible processes because they build up their miscibility as they travel through a reservoir. This process is operable where the reservoir crude gravity is high (40° API or more) and the reservoir is fairly close to its original pressure. For a successful displacement it is desirable that the reservoir be fairly homogenous and can contain high permeable streaks. If high permeable streaks prevail, then the injected gas will preferentially take these paths and, therefore, a high percentage of the reservoir may remain unswept.

The high pressure gas process was patented by Atlantic Richfield in the late 1940's and the first field test was started in the Block 21 field in West Texas during 1949. This test is still active and encompasses some 6000 acres. Several other high pressure gas injection projects can be cited, however, in the future this process will probably not be economical in the United States because large quantities of high priced natural gas are required. This type process has more applicability in foreign oil fields where no natural gas market is available.

### Enriched Hydrocarbon Gas Displacement

In this process the injected gas is enriched with enthane, propane, and butane and as it moves through the oil reservoir it enriches the oil until it becomes miscible with the enriched crude system. The enriched gas displacement process is applicable to lower pressure reservoirs and lower gravity crude systems. The enriched gas drive process, like all displacement processes, works best in homogeneous reservoirs and, like all gas injection processes, works best in homogeneous reservoirs where the force of gravity can be used to retard the channeling tendencies of injected gas.

Several enriched gas drive tests have been made, however, like the high pressure gas process, its economic viability in the U.S. on a large scale would be questionable in the future because of the cost of the large light hydrocarbon requirement.

### Water Driven LPG Slug Drive

In the water driven LPG slug process, injected water drives an LPG slug which displaces the crude oil. The LPG is directly miscible with the crude oil and, therefore, can be applied to a wide range of crude types under fairly low pressures. Linear flood tests in the laboratory have shown it takes only a small slug of LPG followed by water to displace all the oil from a core, leaving only LPG residual saturation. Unfortunately, in the field where radial type flow geometry prevails and the reservoir is heterogeneous, much larger LPG slugs are required for their integrity and, thus, miscibility to be maintained from the injection well to the producing well.

A large number of LPG slug displacement tests have been tried and most have not shown to be adequately better than waterflooding to warrant the additional costs for the LPG. One noted exception to this could be the Parks field where Mobil put in a 7,145 acre water driven LPG project in 1957.[4] Publications on this project do not seem to conclusively prove this project to have recovered more oil than a conventional waterflood, however, increased oil allowables probably made the project an economic success.

Water Driven Carbon Dioxide Displacement

Published laboratory work has shown that carbon dioxide is conditionally miscible with certain crude oils under the proper pressure conditions. Below the critical pressure for miscibility, a carbon dioxide displacement is still somewhat superior to a conventional water displacement in that it leaves lower residual oil saturations.

The first large scale, field-wide carbon dioxide displacement project, in the planning stages over the past four years, was started in the Kelly Snyder Field (Sacroc Unit) earlier this year.[7] This field is one of the major oil fields in the U.S. with over 2.75 billion barrels originally in place. It has been under water pressure maintenance for the past 18 years but 50 percent of the field has not been invaded by water. It is planned to inject a volume of carbon dioxide equal to 20 to 30 percent of the reservoir pore volume in alternate slugs with the injection water. Oil recovery is expected to be 50 percent more than from a conventional waterflood. Some 150MM CFD of carbon dioxide is being piped 220 miles from West Texas gas fields which produce considerable carbon dioxide along with natural gas.

Thermal Recovery Processes

Thermal recovery processes include the forward combustion or "insitu combustion" process, the steam simulation or "soak" process, and the forward steam drive process. Usually these processes are considered for recovery of heavy viscous oil reservoirs, however, the forward combustion process is applicable for recovery of oils under a wide range of conditions.

Forward Combustion Process

The use of the forward combustion process (insitu recovery) as an oil recovery method has received a great deal of attention. This method consists of initiating combustion in the formation surrounding an injection well and driving this heat wave or combustion zone through the formation toward offset producing wells. As the combustion front progresses through the reservoir, oil and formation water are vaporized, driven forward in the gaseous phase, and recondensed in the cooler part of the formation. These distilled liquids, water of combustion and gaseous combustion products, form a bank or three-phase region ahead of the burning front. This bank pushes mobile reservoir fluids toward the producing wells. The rate of movement of the combustion front is controlled by the rate at which the non-distillable residue, which serves as a process fuel, can be completely burned off the sand.

The quantity of air required to burn one acre-foot of a reservoir is called the air requirement, and is unique for each reservoir. The air required should be unaffected by the depletion stage of a reservoir, because saturations immediately ahead of the combustion should be the same regardless of the reservoir fluid saturations. This air requirement and the quality of oil in place are the critical parameters affecting the operating performance and economics of the process. The air requirement is doubly important because it dictates the air compression costs per acre-foot of reservoir, and indicates the amount of oil which is burned and hence unrecoverable. Forward combustion is a high cost process and requires a high oil content in the reservoir for the process to be economical. Favorable conditions for an insitu fireflood are in general the same as those for a waterflood, however, a fireflood is applicable to recovery of much more viscous oil, provided the rock permeability is high enough.

There have been a number of firefloods tried. Bleakley lists some 40 projects currently operating.[4] Very few of these projects are claimed to be economic, however, under favorable conditions of homogenous reservoir rock, good mobility, mid-range oil gravity and high oil saturation, the process is economical.

In order to improve the economics of the process, water is sometimes injected simultaneously with air or it is injected during the later stages of the fireflood after air injection is stopped. This modification has been shown in the laboratory to reduce the air requirement and it improves the transfer of heat forward into the cooler oil regions ahead of the firefront. The improved heat transfer reduces the oil viscosity and, therefore, increases the oil producing rate.

Steam Soak

The steam soak process has been the most successful of the thermal processes. It has been used almost entirely in California where extremely thick high permeability reservoirs contain oil so viscous that their initial flow rates are usually only a few barrels per day.

The steam soak process involves the injection of steam into a well completed in a viscous oil reservoir for a few weeks to several months. The well is shut in for a few days to "soak." The steam heats the oil in the vicinity of the well base and reduces its viscosity. When the well is put back on production, its production rate may increase from several to 50 times its former production rate. After a couple of months, its production rate will drop, approaching its original rate before heating. A second steam injection period is then started, etc.

Even though the oil viscosity is reduced around a wellbore, there must be reservoir energy available for a significant increase in productivity to occur. Most of the California projects are conducted in reservoirs with thicknesses of 50 to 500 feet and the force of gravity is the predominant recovery mechanism. Solution gas drive and, in some cases, water drive are also possible producing mechanisms for a successful steam soak project.

Steam soak projects had their beginning in the early 1960's and by 1968 there were some 14,000 wells actively involved in steam injection. At that time, the production rate due to steam operations was 140,000 BOPD which was 13 percent of the state's production.[8]

Forward Steam Drive

In this process, steam is continuously injected into the reservoir in the same manner as water is in a waterflood. The leading edge of the displacement is a hot waterflood. The forward drive process not only reduces the oil viscosity, but, in addition, it supplies the energy, as does a waterflood, to displace the oil into the producing wells. Theoretically, the process should perform best in thick reservoirs (where heat losses outside the oil reservoir are minimal), with a highly viscous oil saturation, and which are relatively shallow so that well costs are low. In practice, steam drives have shown poor sweep efficiencies due to reservoir rock heterogeneities and due to the effect the force of gravity has upon the flow mechanisms.

All of the forward steam drive projects were started in the 1960's and 1970's. Bleakley lists only five projects encompassing over 100 acres and three over 1,000 acres in extent.[4] Most of the steam drive projects are in California and are outgrowths of a series of steam soaks where communications between wells have been established. About half of these are considered economic.

## SUBSTITUTE OIL SOURCES

There are two major sources of oil that exist in a solid or non-fluid state. These are oil shale and tar sands. Commercial development of tar sands has already started and commercial development of oil shale appears to be eminent. The potential of these sources of oil is great and their commercial development will affect the development and use of new extraction technology for conventional crude reservoirs.

Oil Shale

Major accumulations of oil shale deposits of potential economic value exist in the Green River formation in Colorado and Utah. The Piceance Basin of Western Colorado contains the richest, thickest, and most uniform deposit of oil shale, ranging in thickness up to 2,000 feet. The National Petroleum Council's study on energy has classified oil shale in four categories.

Class 1 - 34 Billion Barrels in place.

Deposits greater than 30 feet thick with an average richness of 35 gpt. and having easy accessibility.

Class 2 - 95 Billion Barrels in place.

Deposits greater than 30 feet thick with an average richness of 30 gpt. and having easy accessibility.

Class 3 - 186 Billion Barrels in place.

Deposits with a richness of 30 gpt., less well defined than Class 2 and not as favorably located.

Class 4 - 1466 Billion Barrels in place.

Deposits with richness ranging from 15 - 30 gpt., less well defined and not favorably located.

Class 4 reserves are only speculative and are not expected to have any value before the year 2000.

When heated to about 700° F, kerogen, the solid organic substance in oil shale, breaks down into shale oil and a low BTU gas.

Most research and development in oil shale exploitation has been directed toward mining the shale from adit mines and crushing and retorting it at the surface. Large, above ground, prototype resorts have been operated by the Bureau of Mines, Union Oil of California and Colony Development Company.

Colony Development Corporation (Atlantic Richfield is the operator) has recently discontinued operation of its 1,000 ton per day prototype plant and is now studying the economic feasibility of building a 50M BOPD plant which might be on stream in 1977 if the decision to go ahead is made within the next year. It is clear that oil shale process technology has been developed to a point where, with the projected relative low rate of return, the risk factor is the major obstacle that stands in the way of commercial development. The NPC estimates by 1985 that oil production from oil shale could reach 750M BOPD.[9]

Tar Sands

The Athabaska Tar Sands are the major tar sand deposits in North America and were the first and only deposit to have a large commercial exploitation project. They are located in northeastern Alberta and are estimated to contain some 600 billion barrels of oil; 10 percent of this is recoverable by mining and extraction techniques and the rest would have to be exploited by insitu recovery methods.

The Great Canadian Oil Sands, Ltd., operation started in 1968 was a design capacity of 45,000 BOPD. It is located along the Athabasca River where overburden ranges from 0 to 145 feet and the tar sand zone averages 175 feet, of which the usable portion averages 13 percent bitumen. The tar sands are mined with two giant bucket-wheel excavators, each capable of digging 100,000 tons a day under favorable conditions. The GCOS operation uses the hot water separation process and a delayed coking-hydrodesulfurization upgrading procedure which yields a 45° API sweet crude.

During the first three years, several operational problems prevented the plant from reaching full capacity, but now it is said to be operating over design capacity, at about 50,000 BOPD. In 1971 the operation was said to be breaking even after losing some 80 million dollars over the first four years.[10] At that time the realized crude price was $3.27 per barrel, and it was estimated that a price of $3.80 per barrel would be a break even proposition, taking care of all non-cash charges. The GCOS has an application before the Alberta Conservation Commission to increase its permit to 70,000 BOPD.

A second tar sand exploitation permit to produce 125,000 BOPD has been granted to a combine, called Syncrude Canada, Ltd., which is owned by Imperial Oil, Cities Service, Atlantic Richfield and Gulf Oil. This project is scheduled to begin construction in 1973 and be onstream in 1976. It is planned to mine with drag lines, use the hot water separation process and upgrade using the H-oil process. It is estimated by 1985 that from 500M to 1000M BOPD will be produced from the Athabasca tar sands.

## CONCLUDING REMARKS

It is expected that improvements in engineering control and application of new recovery techniques will increase the recovery efficiency from the present 31 percent to 37 percent by 1985. A total of 425 billion barrels has been discovered in the U.S., 96 billion of this has been produced. A part of the remaining 331 billion is a target for improved recovery techniques as the price of oil increases. The potential reserves available from tar sands and oil shale greatly exceeds any that will be made available by applying new recovery techniques to existing oil reserves.

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