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# Technology Development

*for Conventional Petroleum Reservoirs*

## Abstract

In the search for new conventional oil and gas reserves, operators are moving into more challenging reservoirs making many conventional drilling, completion and production systems ineffective or uneconomical. At the same time, gas coning and high water production in mature oil and gas fields lead to increased operating costs and impairment of production which force operators to seek innovative approaches to these technical challenges. As producing fields mature there should be increasing emphasis on improved oil recovery (IOR) processes despite their unique economic challenges. This article presents an overview of selected new and emerging technology development areas in reservoir recovery for conventional petroleum reservoirs.

## Introduction

In the search for new conventional oil and gas reserves, operators are moving into more challenging reservoirs where deep water, unconsolidated formations, high pressure, and temperature, solids and sour fluids make many conventional drilling, completion and production systems ineffective or uneconomical (Figure 1). At the same time, high water cuts in mature fields lead to increased operating costs and impairment of hydrocarbon production which force operators to seek innovative approaches to these technical challenges. Conventional oil and gas producers are also under increasing pressure to operate under strict environmental guidelines. Foremost in the public's eye is

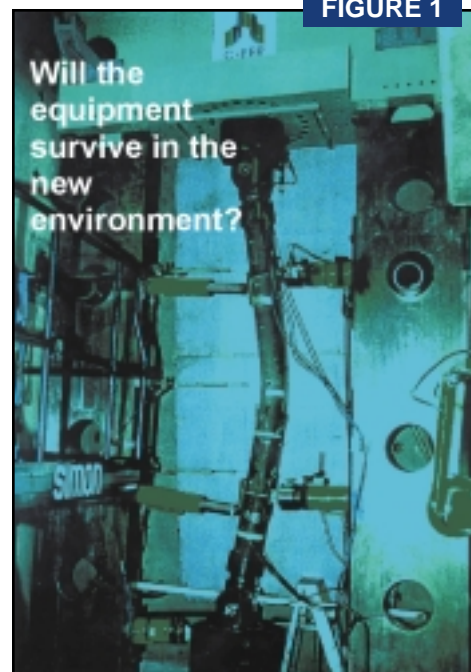
the issue of global warming due to greenhouse gas (GHG) emissions. New technologies for reducing flaring and fugitive emissions and increasing energy efficiency are all becoming important components of the conventional oil and gas industry. This article presents an overview of selected new and emerging technology development areas for conventional petroleum reservoirs.

As producing fields mature there should be increasing emphasis on improved oil recovery (IOR) processes, but IOR poses unique economic challenges due to:

- Less well proven technologies in terms of their response to uncertainties in resource characteristics as compared to those in conventional operations,
- The generally long response periods (two to four years) following investment, overall returns being very sensitive to optimization of operations during late stages of these projects, and
- Challenges posed by instability of oil price and security of markets.

Industry's response to the perceived risks/rewards from IOR has been to concentrate on large, more prolific pools in early stages of

FIGURE 1



depletion; to focus on the best parts of projects; to use technology offering the least risks; to conduct projects in several stages in order to minimize capital, environmental, and operating requirements (and also the risks); to upgrade involvements in technology, man-power and infra-structure (whenever justified); and to process produced water and gases for reinjection or resale. At times, the industry has reacted by passing up the opportunity altogether. There would be a greater tendency to make positive IOR project investment decisions, if risks could be managed, i.e., ways could be found to maximize chances of a favourable outcome, and limit the likelihood (and potential harm) of an unfavourable outcome. In the future, effective use of technology for intense economic and technical screening, prudent planning and selection of IOR projects will be even more critical as the industry moves to implement IOR under adverse economic conditions.

## Drilling, Completions, and Production Systems

The technologies required to operate in new, challenging reservoirs and for continued production in mature fields fall into four key technical areas:

- Developing new systems for severe environments;
- Increasing equipment reliability;
- Reducing operating costs in mature fields; and
- Reducing or eliminating environmental impact.

## Systems for Severe Environments

Some of the challenges being faced by operators in severe well environments include:

- Susceptibility of downhole equipment to damage caused by  $H_2S$  and  $CO_2$ ;
- Elastomer selection for high temperature and pressure service;
- Downhole equipment applications in deviated wells;
- Safety of underbalanced, coiled tubing drilling in sour wells;
- Performance of sub-sea pipelines and other equipment in deep water; and
- Equipment fouling and erosion in high rate wells producing solids (fines)
- Paraffins, asphaltenes, hydrates, and corrosion.

Over time, a given technology is often used in gradually more severe environments until, at some point, failure rates become more frequent than in the less severe environments. When this occurs, the operator has the option of either limiting the use of the equipment to less severe environments or modifying the

equipment to function in the new environment.

Designing equipment for severe environments can be a complex task that must account for issues such as material degradation and combined loading. In some cases, failure mechanisms can include a complex combination of factors such as corrosion/fatigue or sulfide stress cracking. In these circumstances, predicting equipment performance is difficult without sophisticated theoretical modelling and full-scale testing.

Testing may include repeated pressure, load and thermal cycling to simulate equipment operating cycles, and/or exposure to sour and corrosive environments to investigate the interplay between chemical attack and mechanical performance. Often, to reduce the cost of testing, the conditions in the laboratory simulation are modified to accelerate failures that occur over extended periods of time. This may include increasing the load or pressure, increasing the cycling rate or using a more corrosive environment. Care must be taken in the experimental design phase so that changing the environment and loading conditions does not change the critical failure mechanism from what is occurring in the field.

Laboratory simulations are usually complemented by advanced finite element analysis investigations of mechanical components to help in the design of the experiments and extrapolation of the results. Through the combination of testing and analysis, products can often be improved to increase their serviceable range or to increase their reliability in field installations.

Although testing and analysis can be expensive, proper equipment designs for severe environments can reduce the risk of even more expensive trial and error field implementations.

## Improving Equipment Reliability

The first step in improving equipment reliability is to understand the failure circumstances. This is often achieved through a rigorous collection, synthesis and analysis of field data to determine where and under what circumstances the failures are occurring. These data collection efforts often require a number of operators to pool their data in an industry-consortium project to gain sufficient coverage of different reservoirs and operating conditions and enough data in each situation to generate statistically significant results.

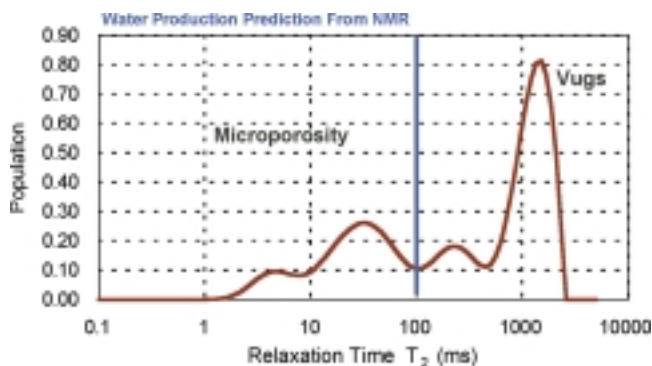
One of the most useful tools in analysing equipment failures is a fault tree that lays out the sequence of events, or faults, that must combine for a certain type of failure to occur. By working backwards from the failures reported in the field, the components or characteristics of the equipment that are more prone to failure can be identified. Numerical modelling and testing under controlled laboratory conditions can then be used to pinpoint the root cause of the failures and to evaluate changes in the design or operating practices to mitigate future failures.

The last component of this type of development, that is often neglected, is tracking the performance of the "improved" design relative to the performance of the original to evaluate whether, in fact, the design has been improved.

## Reducing Operating Costs in Mature Fields

In many mature fields, water cut is the key factor in the field economics due to the water lifting, handling and disposal costs. Ongoing research can help. For example, in carbonate reservoirs, predictions of water

FIGURE 2



production from water saturation calculation values alone may be erroneous. In a significant number of reservoirs, water-free hydrocarbon production has been observed from zones in which high water saturation values have been obtained from the electrical resistivity readings. One possible reason for the water free production is the presence of micro-porosity, which traps the formation brine by capillary forces. To aid in the prediction of water production, nuclear magnetic resonance (NMR) logging is currently being offered as a tool in which pore size discrimination is possible. In circumstances where high water saturation is indicated, the NMR response will indicate the nature of the pore space containing the formation water (Figure 2). Although this solution seems ideal, NMR logging measurements are in their infancy, especially in carbonate formations and much work remains to be done in the interpretation of NMR data in order to develop a reliable technology. Current research is aimed at determining the relationship between the bound water fraction, resistivity measurements, and the low field NMR resistivity response for a number of carbonate reservoir types, with a view to developing a reliable numerical model and procedure which will augment the analysis of current NMR/resistivity wireline data.

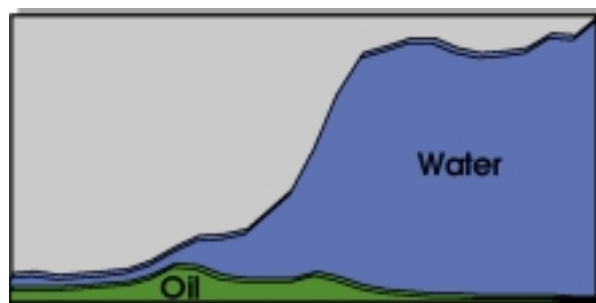
In other areas a variety of downhole fluid processing systems have been developed to separate the hydrocarbon and water streams so that the majority of produced water can be injected directly into a disposal zone, in the same wellbore, without bringing it to surface (Figure 3). Field implementation of these systems requires detailed analysis of the deliverability of the reservoir, injectivity of the disposal zone and performance of the downhole equipment. Also, if an operator waits too long to consider these systems, the capital cost of retro-fitting existing wells may make conversion to downhole processing uneconomic. The economics of these technologies can be significantly improved by designing new wells to allow easy conversion to downhole processing, and of installing them early in the life of the field. Ongoing developments of downhole oil/water processing systems include systems operating with beam, progressing cavity and electric submersible pumps. More advanced downhole separation systems are able to handle produced solids to avoid injection zone plugging.

## Providing for Greater Reservoir Access

The advent of horizontal wells in the early 1980s and the continuing decrease in cost of drilling has seen a momentous switch from vertical wells to use of horizontal wells in a variety of enhanced oil recovery schemes that benefit from increased reservoir access. In Canada, the first horizontal well was drilled in 1978; as of March, 2000 more than 11,000 horizontal wells have been drilled<sup>(1)</sup>. Of these, about half were drilled in conventional and medium-light reservoirs, and the rest in heavy oil and bitumen reservoirs. The Canadian industry experience using horizontal wells has been described in a study<sup>(2)</sup>, which along with our own updated understanding is summarized below:

- Drilling and completion techniques for horizontal wells reservoirs are now largely routine. The equipment to drill horizontal wells in shallow deposits, however, needs further development.
- Formation evaluation (logging, coring and seismic) is limited due to costs. Reservoir description will likely be short-changed in heavy oil and bitumen commercial operations since the low value

FIGURE 3



How can mature wells be produced economically?

product would not likely justify more than rudimentary formation evaluation.

- Fibre optic technology to measure temperature and pressure along the wellbore works well except at temperatures above 250° C.
- Multilateral well technology includes the drilling of either horizontal well sections from a single vertical well or multiple horizontal wells drilled from the main horizontal well. Multilateral technologies have a great future but are at an early stage of development. Multilaterals have many potential applications in heavy oil and offshore reservoirs. A major limitation will be access (for remedial work) and control of the branches to ensure efficient operations.
- In poorly consolidated sand, horizontal wells likely will do no better than vertical wells due to sanding.
- In bottom water reservoirs, horizontal wells show less of a tendency to water coning than vertical wells provided the crude is relatively light. In extra heavy oil reservoirs, water coning will render horizontal wells no more efficient than vertical wells.

Operations of horizontal wells are complicated because there is less control of fluid entry over the length of the well and remedial action, including the use of coiled tubing, is more complex and costly. Lack of understanding or information about the flow patterns in the reservoir contributes to operational complexity and makes predictive modelling difficult if not misleading. A major challenge is the screening of prospects for horizontal wells. This requires geological reservoir description, including a study of the producing characteristics of the pools; in greater detail than is available at the present time. Major new innovations required to better operate horizontal wells and improve performance will emerge in “intelligent” tools for sensing, measurement, and control. These must be inexpensive and still allow for direct detection of fluid flow and patterns in the reservoirs that in turn will control the rate, extent and the position of fluid entry in the wells.

The concept of downhole fluid processing has also been extended to gas wells where the systems address a wide range of operating scenarios where water impairs production. These systems reduce the water loading to facilitate economic flow rates, while removing the water and injecting it into a disposal zone in the same wellbore.

## Flaring Mitigation and GHG Reduction

The use of flares to dispense with excess gas at well sites and oil treating facilities has recently come to the

**FIGURE 4**

**How can emissions be cut?**

forefront of environmental issues for the Alberta oil and gas industry. Proposed solutions to reducing the impact of flaring include: the development of more efficient and reliable flares and energy conversion systems to use the gas as a primary source of energy for either heating or generating electricity. Industry is faced with the challenge of determining which of these technologies is viable and where they can be applied. To address this challenge a multi-stakeholder group that includes government, petroleum producers and equipment vendors is evaluating the proposed development of a Flaring Mitigation Centre (FMC) to advise industry and establish performance standards for manufacturers who develop and supply new equipment to reduce the environmental impact of waste gas (Figure 4).

The rapid growth in Alberta's oil and gas industry is currently leading to questions of how this growth can be sustained while still complying with the Government of Canada's commitment to the Kyoto Accord, to reduce greenhouse gas (GHG) emissions to 6% below 1990 levels between 2008 and 2012. The Alberta Strategy for Action on Climate Change, announced in October 1998, recognized the risk of GHG emissions and their contribution to climate change. The strategy recommends precautionary measures to reduce the growth in emissions, provided these measures maintain the competitiveness of individual sectors of the Alberta economy and the province as a whole. The Alberta Strategy emphasizes that the long-term solution to the GHG challenge will be based on innovation and technology to address pollution control as an integral part of high-efficiency energy production.

## The Future of Conventional Oil and Gas

In the following sections we discuss reservoir recovery technologies aimed at improving oil and gas recovery. As conventional oil producing operations mature improved oil recovery beyond waterflooding becomes enticing but comes with challenging economics. Injectants are expensive, with both chemicals and hydrocarbon gases tracking the oil price. Applications to field wide projects are expensive, with high initial costs of injectants, injection equipment, infill wells, and conversion of existing wells, before incremental oil production begins. This leads to the concept of productivity improvement technologies focussed on single wells or small patterns which involve small treatment sizes. These can be less expensive while retaining the potential for highly effective improvements.

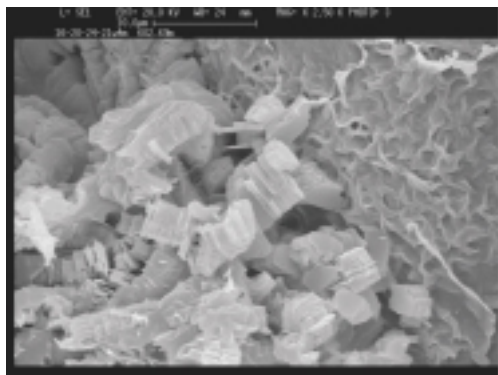
## Gas Reservoirs

Throughout the oil price volatility of the past couple of years, natural gas has maintained a strong price. New pipelines have been or are being constructed to major markets, resulting in a focus on natural gas development by many producers. The new challenges are corrosion, equipment erosion, and handling of oily gas. Some of the reservoir problems associated with natural gas development are near well-bore in nature.

### Phase Trapping Removal in Natural Gas Reservoirs

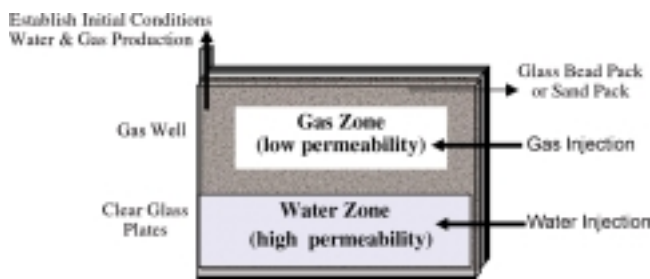
Natural gas exploitation in the Western Canadian Sedimentary Basin has been growing and will continue to increase in the future (Western Canada Supply/Deliverability Study, Ziff Energy Group, 1998). In natural gas exploration, when drilling, fracturing and completion fluids come in contact with such a reservoir, the formation rock imbibes the aqueous fluids, increases the water saturation, and dramatically reduces the relative permeability to natural gas in the near well region. High capillary pressure retains aqueous fluids in the pores and essentially blocks the gas flow into a producing well. This near well formation damage mechanism is called *phase trapping* and has received much attention in the industry. Conventional matrix acidizing in this situation is not very effective. Hydraulic fracturing is more effective but expensive. Norand Technology Centre developed a formation heating treatment (FHT) technology<sup>(3)</sup>. In this method, nitrogen gas is heated to more than 800° C and injected down hole to dehydrate clays and vapourize the trapped water (Figure 5). FHT has been tested in the field but its economic success has not been established to date.

We are working to develop a phase trapping removal technology using a water miscible solvent of low boiling point that can be selected and injected into the near well region. The concept is that the solvent will be injected as a liquid and at a temperature lower than reservoir temperature. After the injection, the well would be shut-in. The solvent would be mixed with water during injection and the shut-in period. When the near-well temperature has equilibrated with the reservoir temperature, the well will be opened. The pressure release will flash the solvent-water mixture. Evaporation of trapped water will therefore remove the phase trap in the near well region. Conceptually, the solvent technology should be cheaper than FHT because FHT requires a rather complex surface facility to heat the nitrogen gas. Pumping solvent should be more straightforward. Another aspect of current research relates to the characteristics of tight natural gas reservoirs, including variations in depth, temperature, and pressure, the distribution of water saturation, pore size, and capillary pressure. These characteristics are needed for the solvent selection process. It is reported that Halliburton Energy and Trican Oilwell Services are currently pumping liquid CO<sub>2</sub> phase trapping removal. However, our preliminary study has indicated that to make this process effective, the miscibility of liquid CO<sub>2</sub> and water have to be improved. The miscibility of liquid CO<sub>2</sub> and water are very much dependent on the reservoir conditions, especially temperature and pressure. This research is aimed at identifying the technical and economical feasibility of using a water miscible solvent to remove phase trapping in natural gas reservoirs.

**FIGURE 5**

Courtesy of PanCanadian Petroleum.

**FIGURE 6**



**Parallel plate model initial conditions.**

## Water Abatement in Gas Reservoirs

A significant amount of research has been aimed at improving gas-well production suffering from water coning and channelling. A pilot test of nitrogen injection into an aquifer underlying a gas pool showed a short-lived reduction in water production. Injecting polymer into tight gas reservoirs has proven to be a viable technique for reducing water production in true coning situations in the near-wellbore region. However, in situations where well inflow is primarily via fractures, placement of a cross-linked polymer is the desired treatment. In 1999, we successfully carried out such a field trial in a deep fractured carbonate gas reservoir; the treatment paid out in four months.

In order to improve the gel placement strategies, the fundamental transport mechanisms during sequential gel/gas injection need to be understood. Figure 6 illustrates a 2D parallel plate model replicating a fractured gas reservoir with a severe water production problem. Current research is aimed at improving the success ratio of injecting gel overdisplaced with gas to control water channelling/coning in gas wells. Gel placement in gas wells for water blocking, without significantly

reducing the gas production, is the major challenge. Several gas-producing companies are scheduled to conduct field pilots with this technology in Canada at an activity level that will permit us to assess what works, what does not work, and why.

## Light Oil Reservoirs

### Microscopic Displacement Efficiency in Waterflooding

Laboratory research using magnetic resonance imaging (MRI) is providing an improved understanding of how reservoir heterogeneity and pore space characteristics affect microscopic displacement efficiency during waterflooding. For example, nuclear magnetic resonance (NMR) relaxation data from brine saturated rock samples can provide a detailed look at the pore size variation while NMR imaging provides a detailed view of the spatial variation of the pore space. The presence of vugs and fractures (mud filled or fluid filled) can be detected easily. A database of such images and measurements is now available for over 100 carbonate reservoir cores<sup>(4)</sup>. MRI provides a means of examining the flood efficiency in situ and is quantitative for carbonate samples. It is superior to traditional techniques for unsteady state imbibition floods when the produced volumes are small or in steady state floods because saturations are measured directly. MRI in situ saturation profiles acquired during laboratory-scale waterflooding improve the determination of the relative permeability functions because heterogeneous flow, end effects and unstabilized flow behaviour can be detected directly and the confidence limits of the data estimated. Current work centres on the investigation of how pore space properties (depositional environment variations) and sample heterogeneity affect relative permeabilities in carbonate samples.

## Chemical Flooding

Conventional waterflooding results in large quantities of oil being left behind due to poor sweep efficiency and poor displacement efficiency. As observed in a recent review<sup>(5)</sup> "we have little choice but to strive to make EOR (enhanced oil recovery) work, because the oil remaining in the reservoirs after primary recovery and waterflooding can range from 50 – 60% of the original oil in place (OOIP) in the case of a light oil . . . The volume of such "unrecoverable" oil in existing reservoirs is about  $5 \times 10^9$  m<sup>3</sup> (30 billion barrels) in Canada, and about ten times as much in the U.S.A." Chemical flooding, whether micellar-polymer or alkali/surfactant polymer, provide a means to reduce waterflood residual oil saturation and improve sweep efficiency at the same time.

### *Micellar-Polymer Flooding*

Some of the largest conventional oil reservoirs discovered thus far in Canada, such as the Pembina Cardium, Turner Valley, and Provost-Viking, have been extensively waterflooded since the late 1950s. Such operating waterfloods are now reaching their economic limits and improved oil recovery techniques are being considered to extend the lives of the reservoirs<sup>(6)</sup>. Modern micellar-polymer flooding may well be a viable option for such reservoirs<sup>(7)</sup>. Lowering the interfacial tension between reservoir brine and oil to such ultralow values that micro-emulsification occurs ( $< 10^{-3}$  mN/m), by injecting a properly selected surfac-

tant solution into a reservoir, has been proven to be tremendously effective in reducing residual oil saturation. The injected micellar fluids are complex formulations containing surfactants, cosurfactants, cosolvents, and polymers<sup>(8-10)</sup>. Petroleum sulfonates are the most commonly used surfactants<sup>(11, 12)</sup>, although others have been used<sup>(13, 14)</sup>. Water-external microemulsions are used in some processes, such as the Maraflood<sup>TM</sup> process, while soluble-oil<sup>(15, 16)</sup> microemulsions are used in others, such as the Uniflood<sup>TM</sup> process. Perhaps not surprisingly, micellar fluids exhibit complex phase behaviour and salinity effects under reservoir conditions<sup>(17-20, 23)</sup>. In practice, due to economic constraints, a finite chemical slug must be injected and effectively displaced through the reservoir. The use of a salinity gradient produces a suitable environment at the trailing edge of the chemical slug to permit miscible displacement by a polymer drive fluid. The salinity gradient approach also minimizes surfactant adsorption on the reservoir rock, an effect that otherwise makes micellar flooding uneconomic. A number of reviews are available on the micellar/polymer process itself<sup>(21-24)</sup> and on the many field trials<sup>(25-28)</sup>. Many field experiments have failed or have displayed poor performances because of inadequate well patterns, poor knowledge of reservoir characteristics, or degradation of chemicals, leading to loss of mobility control. Some pilot tests, with better reservoir characterization and properly designed chemicals, have been reported to be technically successful with recoveries in the order of 50% of the oil at the start of the flood, recovering two-thirds of the residual oil<sup>(29, 30)</sup>. We recently developed a micellar flooding process for a pool in the Pembina Cardium region<sup>(31)</sup>.

#### *Economic Enhancement of Incremental Oil Recovery*

Concerns over the chemical costs associated with micellar-polymer flooding have prompted a significant amount of R&D into lower-cost chemical flooding. Much less expensive alkali can be used to produce surfactant from the crude oil itself, and the alkalis such as sodium carbonate can be selected to minimize detrimental rock-fluid interactions<sup>(32)</sup>. Next, a very small amount of co-surfactant is added to further reduce interfacial tension, and then polymer is added to further improve interfacial performance and sweep efficiency. An efficient and economic alkali/surfactant/polymer (A/S/P) process can often be developed for specific reservoirs by testing the reactivity of the oil with respect to an array of alkaline, surfactant, and polymer chemicals, adsorption measurements specific to the reservoir rock, and finally reservoir-condition laboratory coreflood evaluation<sup>(33)</sup>.

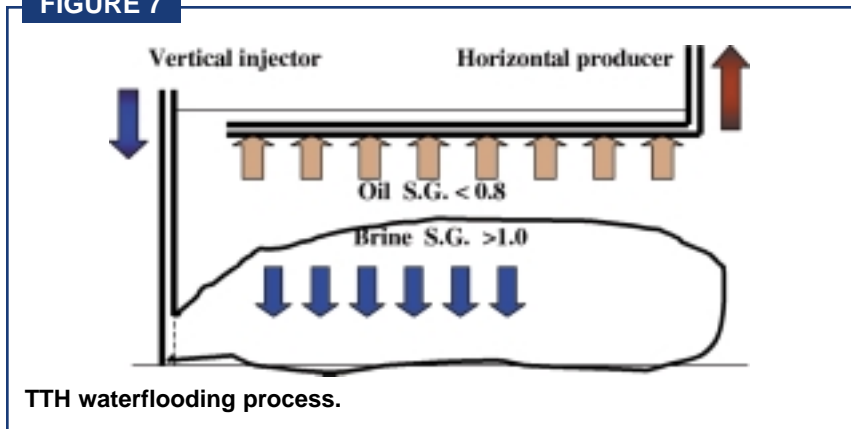
The A/S/P process has been well documented in the literature<sup>(32)</sup> and several successful field trials have been conducted, reporting recoveries of 40 to 50% of waterflood residual oil at costs as low as \$3 per incremental barrel of oil. Recent research coupled with the increased use of horizontal wells may open new opportunities for effective use of this process. Also, early studies demonstrated that the alkali reacts with the organic acid components of the crude oil to liberate natural surfactants and often the oil acid number can be correlated to the density of the oil, i.e., heavier oils have higher acid numbers. Therefore, it has become conventional wisdom that only heavier oils would be suitable for the A/S/P process. The discovery that the A/S/P process can be effective at much lower acid numbers greatly broadens its application opportunities.

## Hydrocarbon and CO<sub>2</sub> Solvent and Steam Flooding

### *Solvent Flooding*

Hydrocarbon<sup>(34)</sup>, steam<sup>(35)</sup>, or carbon dioxide<sup>(36)</sup> flooding refer to oil recovery processes in which solvent or steam are injected into a petroleum reservoir. In immiscible flooding increased oil recovery is obtained by achieving a low interfacial tension between solvent and the oil (raising the capillary number). In the case of steam flooding oil viscosity reduction also contributes to increased oil recovery. In miscible flooding the aim is to increase oil recovery by one or more of the following mechanisms, oil displacement by the solvent through the generation of miscibility, oil swelling (increasing the oil saturation and therefore the oil relative permeability), and reducing the oil viscosity. Depending on temperature, pressure, and oil and solvent composition the injected solvent may be completely (first-contact) miscible or may become miscible due to continuous mass transfer of components between oil and solvent during flow through the reservoir (multiple-contact miscible). In some cases the injected gas is enriched with intermediate hydrocarbon components to encourage multiple-contact miscibility. Such solvent injection is usually chased by the injection of a less expensive drive fluid, such as natural or flue gas, or water. Most of the world's enhanced oil recovery production comes from injection of solvent vapour into a petroleum reservoir. Whether hydrocarbon, steam or carbon dioxide is injected, large density and viscosity contrasts exist between the displacing and displaced fluids resulting in poor sweep efficiency in horizontal displacement programs because of gravity over-

**FIGURE 7**



ride and viscous fingering. Much research has therefore been devoted to the development of effective foam injection processes.

### Light-heavy Oil Reservoirs Enhanced Waterflooding Using Toe-to-heel Displacement

For light-heavy oils (with viscosity less than 2,000 mPa.s), conventional waterflooding involves displacement (and flow) of oil for long distances (hundred of metres). Due to the very unfavourable water/oil mobility ratio, the process is plagued with major problems, primarily water channelling in producers. We are now investigating short-distance-oil-displacement (toe-to-heel oil displacement), **Figure 7**, which is a new way of displacing oil, while using horizontal well producers and vertical (or horizontal) injectors. This new technology can be applied to both improved oil recovery (IOR) processes, as well as primary exploitation of oil reservoirs associated with an active bottom water table. In case of IOR we deal with the TTHDP (Toe-to-Heel Displacement Processes), while in primary recovery we deal with the use of the so-called inverted trajectory horizontal wells. In both cases, the horizontal section of the production well is perpendicular to the strike, and water is “forced” to first intercept the horizontal well at its *toe* (toe break-through).

Considerable work has already been done on the propagation of an almost upright displacement front by using 2D and 3D physical model tests, supported by simulation work. These tests suggest that TTHDP applications can lead to high oil rates from the very beginning (no waiting period). Other attractive features are the simplicity of operation and high oil recovery. The current focus on TTHDP is for the case of water injection. Although it belongs to the same category of *short-distance-oil-displacement processes*, like steam assisted gravity drainage/vapour extraction (SAGD/VAPEX) processes, the main difference is that TTHDP processes have a more active drive component, and they seem to be more robust vis-à-vis the effect of heterogeneity. THDP processes also lend themselves to variations that could further increase sweep efficiency, such as water-alternating-gas (WAG) injection, or improve microscopic displacement efficiency, such as alkaline/surfactant/polymer (A/S/P) injection.

### Cold Production of Heavy Oils

Cold production is a primary non-thermal process in which sand and oil are produced together in order to enhance oil recovery<sup>(37)</sup>. Well operators observed that,

for certain wells, aggressively producing the formation sand results in ten-fold or more increases in oil recovery. Improvements in the design and operation of progressive cavity pumps have allowed the sand to be pumped more easily<sup>(38)</sup>. Field and laboratory research indicates that the higher oil recovery is due to a combination of reservoir pressure maintenance during solution-gas drive and to the enhanced permeability of the reservoir when sand is produced<sup>(39)</sup>.

Pressure depletion experiments in sand packs have shown that gas mobility is greatly reduced in heavy oil compared to light oil<sup>(40)</sup>. Greater critical gas saturations were observed for heavy oils<sup>(40, 41)</sup>. The lower mobility is likely caused by gas trapping at pore throats as observed in dual depth micro-models<sup>(42)</sup>. These bubbles take longer to coalesce in the case of heavy oil due to a lower gas diffusion coefficient, higher viscosity and the presence of natural surfactants. Pressure depletion experiments suggest that the rates required for economical oil recovery are much higher than the average pressure depletion rates in the field.

The growth of high permeability channels (wormholes) in a formation likely increases the pressure decline rates locally around the wormholes. Tracer tests, injectivity tests, field observations during drilling and laboratory experiments indicate that high permeability channels (wormholes) develop during cold production of heavy oil<sup>(39)</sup>. Computed tomography imaging experiments suggest that these wormholes grow in the weaker sands in a formation<sup>(39)</sup>. The experiments indicate that wormholes in the field are full of sand when they develop leading to high sand cuts. The wormholes would empty out of sand once they have stopped developing leading to low sand cuts as observed in the field.

We have now developed a field model of cold production that incorporates both the enhanced permeability due to sand production and the non-equilibrium solution gas drive. Oil and sand production rates from typical cold production wells were history matched successfully.

### Foamy Oil Behaviour: Cold Production Processes and Beyond

Foamy oil flow, or the formation and flow of a dispersion of gas bubbles in oil, is one of the important contributing factors in the success of cold heavy oil production. We have had a broad research effort in the area of foamy oil behaviour for several years. Laboratory experiments using foamy heavy oil systems have shown that very high primary recovery factors can be obtained, provided the fluid depletion rate is kept high. The recovery factors obtained at field depletion rates, however, are low and do not match the high recovery factors expected for several field cases. Phase behaviour studies within pressurized fluid containers, with the help of MRI techniques, have shown that some interesting phenomena occur during the release of solution gas by pressure reduction. Their role in the solution gas drive mechanism within the reservoir pore space remains unclear and there are still many unanswered questions. Although the mystery of the driving force behind foamy oil flow remains unsolved, progress has been made in identifying probable mechanisms. Work is continuing to complete the picture. As this research continues and becomes integrated into production practice, improved performance and economics of cold heavy oil production will significantly enhance recovery factors and reserves.

Improving the understanding of foamy oil behaviour

in heavy oil production processes other than cold production should yield significant production gains. For example, we have developed a comprehensive and pragmatic treatment that allows the prediction of foamy oil behaviour in the cold production process (the primary production of heavy oil with substantial sand production). The treatment is based on non-equilibrium gas exsolution kinetics, the dynamic growth of bubbles, and the relative permeability of different types of gas bubbles. Extending this treatment to heavy oil processes such as primary production with limited or no sand production, follow up processes after cold production, solvent stimulated processes, and thermal processes, including cyclic steam stimulation, should allow process and operational improvements. We are working towards improved "rule of thumb" operating guidelines.

## Economically Beneficial Waste Gas Injection for Light-heavy Oil Depletion

Substantial volumes of waste gases are released into the atmosphere by the energy industry from a diverse array of sources:

- Fluid pumping stations and field gas compressors
- Major natural gas cleaning and compression facilities
- Fired thermal-electric generation stations.

Unfortunately, facilities releasing large volumes of waste gases are seldom located near the reservoirs that might utilize them. In addition, most of the waste gases are produced at near-atmospheric pressure and require substantial investment in compression facilities to make them injection-ready. On the other hand, production from many medium-heavy oil reservoirs in the Western Canada Sedimentary Basin yields poor economic returns unless one can enhance drainage and production rates. Recent research has focussed on identifying opportunities where waste-gas availability can be matched with the requirements for gaseous driving fluids to assist in the recovery process, particularly for light- to medium-heavy oil accumulations<sup>(43)</sup>. This also requires identifying the reservoir recovery processes most benefited by waste gas injection through numerical simulation and laboratory studies. As part of this work, attention is being paid to identifying and resolving the facility-related issues associated with capturing/gathering, processing, and injecting of the waste gas. This includes sizing of processing equipment;

addressing corrosion and environmental issues relating to gathering and transportation; monitoring and controlling injection systems; and identifying costs for injection-ready fluid for target reservoirs. Research is needed to assess the beneficial application of waste gas such as CO<sub>2</sub> in light- to medium-heavy oil depletion processes (e.g., pressure maintenance gas, push gas) and beneficial green house gas effects.

## Conformance Control and Water Shut-off

### Mobility Control Processes

Foams can be injected into a reservoir for mobility control or for blocking and diverting. The foam can thus act to reduce the effects of poor mobility ratio

between injected and reservoir fluids, or remedy other causes of poor areal sweep efficiency, poor vertical sweep efficiency, seal off non-oil-saturated or thief zones, or to partially overcome effects due to reservoir heterogeneities. For example, major problems occur in gas flooding methods due to the high mobility and low density of the displacing gas compared with that of reservoir fluids. In such cases, channelling (fingering) and gravity override both reduce the sweep efficiency, contribute to early breakthrough of injected fluid, and therefore reduce the amount of oil recovered. Injecting the gas as a foam can counteract these problems because the foam lowers the gas mobility in the swept and/or higher permeability intervals and diverts at least some of the displacing medium (gas) into other parts of the formation that were previously unswept or under-swept. It is from these latter areas that the additional oil is recovered. Since foam mobility tends to be reduced disproportionately in higher permeability zones, improvement in both vertical and horizontal sweep efficiency can be achieved. Suitable foams can be formulated for injection with air/nitrogen, natural gas, carbon dioxide, or steam<sup>(44)</sup>.

A major challenge is the proper selection of foam-forming surfactants, and there have probably been several hundred papers published in the past 35 years on appropriate foam characteristics, and the necessary characteristics are now well established<sup>(45)</sup>. The economics of foam flooding are determined to a large degree by the amount of surfactant required to generate and propagate a foam. Surfactant loss through partitioning into the crude oil phase and through adsorption on the rock surfaces cannot be completely eliminated, and minimizing these has been the focus of much research<sup>(46)</sup>.

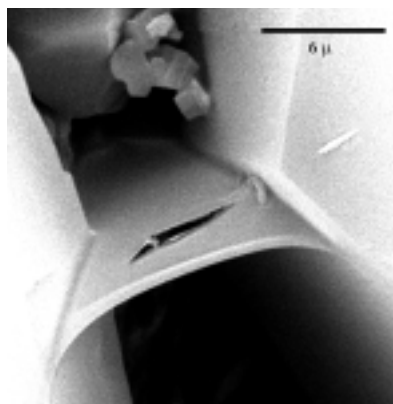
Early field tests were successful but suffered somewhat from the defoaming action of residual crude oil<sup>(47)</sup>, which led to considerable research being applied to the development of oil tolerant foams. Mobility reduction foams that are effective at reservoir conditions, including residual oil saturation, are now available<sup>(48)</sup>. These have been used in the design of foam applications for fields in Canada, the North Sea, and Cuba. Our recent work has also identified other conditions under which foams can be more effective<sup>(49)</sup> and guidelines have been developed for proper generation and placement of foams (preforming of foam, generation in situ, or co-injection) and also for appropriate testing in the laboratory<sup>(50)</sup>.

Polymer enhanced (thickened) foams have also found increasing use in the petroleum industry. Incorporating polymers into foaming solutions primarily increases the liquid phase viscosity, which enhances foam stability by decreasing the rate of drainage and reducing the rate of interbubble gas diffusion. There is a small but growing literature on the development of polymer-thickened foams in terms of both fundamental and applied work<sup>(44)</sup>. Polymer thickened foams along with time-delayed cross-linking agents (gel-foams) can be used to improve the efficiency of oil displacement by blocking swept zones (Figure 8) and by diverting fluids into underswept zones in reservoirs containing large permeability variations and/or fractures. Once gelled, these foams can function in a fashion similar to conventional gels, but with only a small fraction of the pore space being occupied by gelled liquid<sup>(51)</sup>.

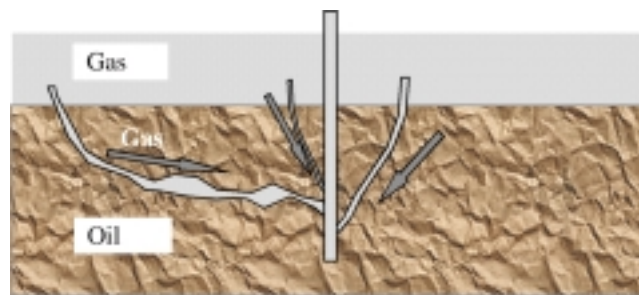
## Anti-gas Coning in Oil Wells

Gas coning is a significant problem in producing wells around the world. Near-wellbore placement of a

FIGURE 8



SEM image of a foam lamella spanning sandstone grains.

**FIGURE 9****Gel foam application: gas channelling problem.**

foam-blocking agent can curtail excess gas production. Although such treatments have been tested successfully in the North Sea and North America, the available foams have a limited lifetime (weeks to months). In order to improve the effective lifetime of foams in improved oil recovery applications, enhanced foams, such as gel-foams, are being designed in which the gelation is sufficiently delayed for the gel-foam to be propagated through the reservoir. Once placed, gelation will progress to completion, effectively gelling the foam in situ. Such a gel-foam has similar placement characteristics as regular foam, and, in addition demonstrates a much longer effective lifetime.

In oil producing wells, the relatively low density of the gel-foam allows it to be placed near the top of the oil bearing zone into the gas cap. Therefore, gas channelling is essentially blocked without significantly reducing the oil production. For injection wells dominated by a thief layer near the top of the pay zone, **Figure 9**, gel-foam placement becomes advantageous. If a gas injection project exists at the target well, then a gel-foam placement can reap additional economic benefits since gas costs would be minimal.

The gas blocking ability of gel foam has been established, both in the laboratory and in the field. Current research is focussed on designing improved gel-foam field applications and investigating the unique properties of gel-foam. Two successful field tests have been carried out with this technology to block gas channelling into an oil well, **Figure 10**, and additional field tests are expected, both in Canada and internationally.

Other applications of gel foam exist as well. Expanding SAGD projects, from pilot scale to commercial scale, requires in some situations that old depleted steam chambers will need to be shut in while adjoining steam chambers are still actively producing oil. In order for the steam/heat not to migrate from the active steam chambers to the depleted chamber, the void space should be filled with a low conductive, immobile, blocking agent, such as gel-foam. This requires the development of high temperature applications. Gel foam may be applied to extending the useful life of production and injection wells by alleviating gas channelling problems in oil wells, conformance problems near injection wells, and sealing off steam chambers in thermal operations.

## Reducing Water Production

The major cause of economic decline in many light and light-heavy oil wells is high water cuts. Reducing the water inflow into the wellbore can significantly increase the life of many wells and increase overall oil production. We are presently engaged in the testing of possible technologies for preferentially reducing water inflow into the wellbore with no significant damage to the flow of oil (**Figure 11**). The profile modification methods under investigation include wettability alteration using crude oil additive combinations, polymers of the type that form a network around sand grains, gas injection methods including anti-water coning (AWACT) technology, and combinations of the above methods.

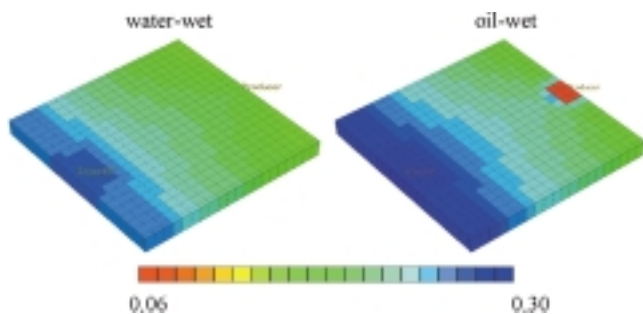
## Water Shut-off in Fractures

Water shut-off and conformance control remain as some of the greatest challenges in the petroleum industry. In Alberta, produced water from petroleum production amounted to more than 3 billion bbls in 1997, averaging more than 6 bbls of water for every bbl

of oil produced. We have developed a water shut-off technology using clay gel. In this concept, bentonite (a naturally occurring swelling clay) is mixed into a proprietary aqueous solution to form a slurry. The composition of the aqueous solution is controlled such that the clay slurry remains fluid at very high clay concentrations. This facilitates the injection of the clay slurry. Once the clay slurry is injected into a reservoir, a cation exchange process takes place spontaneously and transforms the clay slurry into a clay gel, **Figure 12**. The clay gel then plugs the conduits for water. The concept was fully demonstrated in the laboratory.

The initial motivation of developing this system is low cost. Clay gel costs about  $\frac{1}{4}$  of the cost (chemical and delivery) of comparable polyacrylamide gels and less than  $\frac{1}{10}$  the cost of comparable phenol formaldehyde gel. All the chemicals used in the clay gel system are routinely used by drilling fluid companies, and are environmental friendly. If the salinity of formation water is low (less than 3 wt%), the treatment process will be very simple. The clay gel system is only appli-

**FIGURE 10****Gel-foam field test showing well-head and foam generators.**

**FIGURE 11****Water saturation comparison (after 60 hours).**

cable for water breakthrough in fractures and worm-holes. It is not suitable for permeability modification in porous media. When the salinity of formation water is high (greater than 3 wt%), a fresh water pre-flush is required. In that case, pumping time will increase. Five field trials have been conducted to date. We are presently working on the additional field trials needed to fully develop the clay gel technology and have invited producers to work with us to apply this technology. The best cases include short circuit in waterflooding reservoirs and water breakthrough in cold production reservoirs. In addition, we have recently developed a “sandy clay gel” system. In this new development, produced sands are added into clay slurry before injection. Produced sands can reinforce clay gel and displace a certain amount of swelling clays required. This application can also provide an effective and safe method for produced sand disposal. We intend to work with cold production producers to conduct field trials in this area as well.

## Formation Damage

### Non-damaging Drilling Muds

Horizontal wells including multilateral/multibranch completion technologies have shown good performance when damage of the near-wellbore region by the drilling mud was minimized. Conversely, obtaining good performance is often difficult because the time for drilling the horizontal section(s) in the hydrocarbon producing zone is usually long enough to cause severe drilling mud damage. Over the past several years we have evaluated the effect of lost circulation materials (LCM) in alleviating the mud damage for simulated single and multiple fractures. Currently, for the case of fractured rock, the drilling industry is basing the design of LCM on the width of the largest fracture expected in

the target zone. The underlying premise is that the widest fracture suffers the most damage. This assumption is not fully justified from the point of view of either the bridging process itself (for a controlled multiple-fracture system), or the oil flow capacity. The prime role of the widest fracture, both in the production of oil and the mud damage process, should be rigorously assessed. The current knowledge was extended to include the effects of LCM in alleviating drilling mud damage for a simulated multiple fracture system.

Optimum drilling mud systems can now be designed based on fracture size distribution; and on an evaluation of the effect of overbalanced drilling, solids content and the main parameters of LCM. We have developed LCMud software that calculates the type, size, and concentration of LCM for effective bridging of fractures of known aperture. This is a valuable tool for assessing the correct lost circulation material. These advances can contribute to improved performance and reduced stimulation costs for horizontal wells including multilateral/multibranch completions, drilled overbalanced in fractured formations.

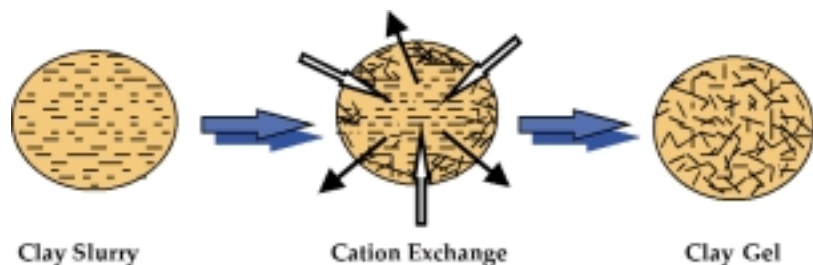
## Well Stimulation to Remove Pyrobitumen

We have developed a patented process, PRiStine™ to treat oil and gas wells which suffer from pyrobitumen problems<sup>(52, 53)</sup>. Pyrobitumen is an insoluble carbon-rich deposit derived from thermal degradation of hydrocarbons. It is a natural material found in sandstone and carbonate reservoirs world-wide in amounts up to 10 wt%. Pyrobitumen is insoluble in organic solvents and acids. There is no known commercial method to remove pyrobitumen which, occludes porosity and reduces permeability. Since the pyrobitumen is insoluble in acid, acid treatments to wells to attempt to increase productivity fail or dissolve surrounding rock, which loosens the pyrobitumen which then moves to block permeability thus further reducing well productivity. We are continuing to develop PRiStine™ for oil and gas well stimulation and are now field-testing the formulation and treatment technique.

## Asphaltene Remediation in Light Oil Reservoirs

Asphaltene deposition is a problem in the solution gas drive of strongly undersaturated light oil reservoirs, usually when reservoir pressure declines to the bubble point pressure. In miscible gas flooding operations using either CO<sub>2</sub> or hydrocarbon-rich gases, asphaltene deposition is a problem usually following the breakthrough of solvent in the production wells. Lack of a clear understanding of the asphaltene deposition mechanisms leading to a reduction in effective permeability (to solvent/oil) in porous media inhibits the development of ways of de-plugging the near-wellbore formation. For instance, it might make a difference in the way one treats an injection well or a production well, and how one treats an asphaltene deposition when different solvent mixtures (Figure 13) are being produced at a well. Also, the cumulative amounts of solvent-oil mixtures may have a bearing on asphaltene deposition (quantity and quality of deposition). For these reasons, very often the treatments for de-plugging near-wellbore asphaltene formation are not very efficient, as they may not be taking into account specific conditions and parameters causing asphaltene deposition.

Recent asphaltene deposition research has shown that the reduction of effective permeability to the oil-

**FIGURE 12****The concept of clay gel for water shut-off .**

solvent mixture occurs much before the flocculation starts. Even the non-flocculated asphaltenes can be retained inside porous media. The theory of permeability reduction due exclusively to the already-formed flocks-outside-porous-media doesn't seem to be valid. For the oil-propane mixtures, the rate of effective permeability reduction is relatively high. This finding seems to be explained reasonably well using the qualitative, micromodels results of other researchers (Chang et al., 1993), who found that at low solvent proportions, cluster-like deposits form, which reduce the permeability significantly, while at high solvent proportions predominantly island-like deposits form. The validity of the theory of cluster-like deposition at low solvent concentration and of cluster + island like deposition at high solvent concentrations remains to be explored. Other research suggests that asphaltene solvent is very efficient for the removal of asphaltene deposition, only when used in the backward injection, that is, when it is flowed in a reverse direction, as compared with the direction of oil-solvent mixture flow at the time the asphaltene deposition took place<sup>(54)</sup>. Ongoing research is aimed at optimizing the asphaltene de-plugging process during the backflow using different solvents and dispersants. Such research should result in guidelines for the design of the asphaltene treatment during primary solution gas drive and gas miscible flooding, taking into account the specific conditions and parameters of the asphaltene deposition process.

## Risk Management and Prediction Tools for Improved Oil Recovery

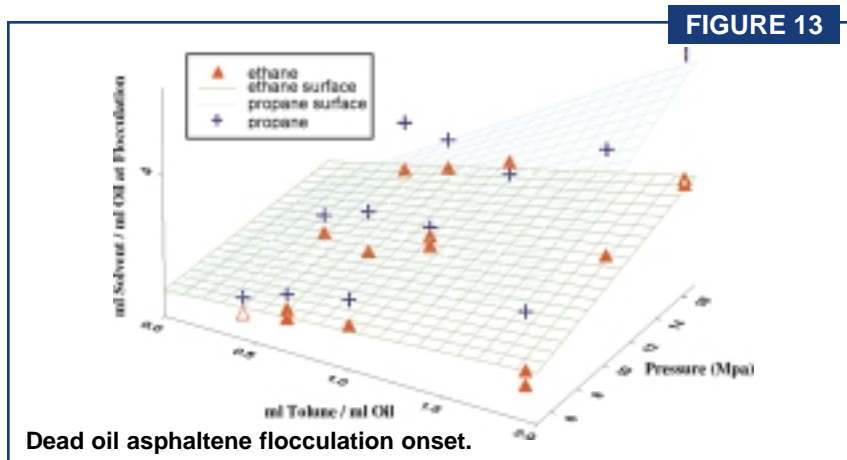
### Risk Management in Improved Oil Recovery Projects

The industry's experience base, over the years, has grown to a point where certain generalizations can be attempted. This has occurred after conducting some one thousand experimental field pilots and about two hundred semi-commercial projects worldwide. For prospects where several IOR options appear feasible (based on resource characteristics, available technology, and prevailing economic conditions at the time of project implementation), the decision boils down to the perception of economic risks and rewards for those processes.

Economic risks could be optimized, among other means, by reducing capital requirements (staging, shared, or used equipment), by reducing response times (closer well spacing, horizontal wells), and injection costs (reducing injectant costs by reducing amount, concentration, pressure, temperature, etc., or by partially substituting more expensive injectant by water, nitrogen, flue gas, air, or methane). Negotiated agreements or long-term contracts could help stabilize economic fluctuation on some of the revenue and cost items. Larger projects may offer opportunities for cost and risk reductions as opposed to small projects. Similarly, certain recovery processes are more amenable to these approaches than others.

Rewards could be enhanced by:

- Enhancing injection and production wells (horizontal wells, stimulated wells, well selection),
- Coning control,
- Ensuring adequate contact between injectant and reservoir fluids (re-completions, small spacing, sweep pattern),
- Paying special attention to conformance and



sweep improvements (foams, emulsions, polymers, gels, sliding sleeve completions, retrievable packers),

- Using gravity to advantage (vertical floods, steam assisted gravity drainage),
- Displacement efficiency enhancing chemical methods (miscible, surfactant, steam flooding, and in situ combustion), and
- Minimizing viscous fingering.

### Computer Evaluation of Reservoir IOR Potential

Integrated analytical software such as PRIZe™ provides quick engineering evaluations of IOR potential of oil reservoirs based on up-to-date published experience and analytical models from the technical literature.

This approach is now in use by more than thirty companies. Constant interactions with users has led to improvements that have increased the usefulness of the program in current engineering practice. The software can provide checks on geological/production/reservoir and primary oil production mechanism data, and can provide estimates for any missing data. Technical screening of prospects for IOR is done by checking the reservoir data against critical parameters using a “go/no go” approach. A waterflood option utilizes a variety of prediction methods in order to take into account such specific characteristics as heterogeneity and water tonguing. The software further performs calculations of incremental recovery, injection/production profiles, and producing gas-oil ratio (GOR) or water cuts for selected processes. The benefits of this software include rapid screening of reservoirs for IOR applications. Some examples can be found in Reference (55).

## Summary

As the conventional oil and gas industry matures, the operating environments are becoming more severe. Operating in these challenging environments will require both refinement of existing technologies and the implementation of new technologies to address the changing needs. Developing these technologies requires a multi-phase approach to design, testing, prototype manufacturing, and field implementation. Failure in any one of these areas can cause a product with great potential to fizzle. A concerted effort will be required to demonstrate the success of the initiatives discussed. Government, industry and new-technology developers will have to share the risk of field demonstrations and eventual commercialization of emerging technologies.

We have reached a stage at which improved rapid screening of reservoirs for IOR applications and better production forecast modules, based on the most versatile analytical models found in the technical literature, will increasingly provide valuable assistance to reservoir and production engineers seeking to increase production using IOR methods.

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## AUTHORS' PROFILE

This team of authors for this article was drawn from the Alberta Research Council (ARC), which develops and commercializes technologies to give customers a competitive advantage. In the energy sector it works in the following areas:

- Conventional and heavy oil recovery and production technologies, reservoir management processes and protocols, novel downhole and surface oilfield equipment, specialty sensors and instrumentation, upgrading technologies for improved recovery and cost efficiency, and
- Industrial practices and technologies related to water and land management and climate change to ensure sustainable development.

The recent acquisitions of the Petroleum Recovery Institute (PRI) and C-FER Technologies Inc. allow ARC to capitalize on the strengths of three world-class organizations and provide more comprehensive and effective field-proven, new energy technologies to Alberta-based and international industry.