"A comparative analysis of microbial enhanced oil recovery(MEOR) and steam assisted gravity drainage(SAGD) techniques for recovery enhancement of a field"

A thesis submitted in partial fulfilment of the requirements for the Degree of

Bachelor of Technology

(Applied Petroleum Engineering, Upstream)

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CERTIFICATE

This is to certify that the **Mr. Nikhil Kaul** and **Ms. Astha Tyagi** have successfully completed their Major Project on ***'A Comparitive Analysis of Microbial Enhanced Oil Recovery (MEOR) and Steam Assisted Gravity Drainage (SAGD) Techniques for Recovery Enhancement of A Field'*** at University of Petroleum and Energy Studies, Dehradun, during 2010-2011.

The Project work is a part of the fulfilment of the Degree of Bachelor of Technology (Applied Petroleum Engineering) + MBA (Oil and Gas Management), to be awarded to them by the University of Petroleum & Energy Studies, Dehradun.

Mr. Pawan Kr.Mandapakka

ABSTRACT

The strategy behind MEOR (Microbial Enhanced Oil Recovery) is injection of microbe with suitable nutrients which produces their metabolic products like gases, surfactants, acids etc or extracellular product of metabolism may be extracted from cultures grown at the surface and solutions of these materials may be injected into the Petroleum reservoir that can aid in releasing oil from the reservoir rock.

SAGD (Steam Assisted Gravity Drainage) is an advanced form of steam stimulation in which a pair of horizontal wells are drilled into the oil reservoir, one a few meters above the other. Low pressure steam is continuously injected into the upper wellbore to heat the oil and reduce its viscosity, causing the heated oil to drain into the lower wellbore, where it is pumped out. The upper well injects steam, possibly mixed with solvents, and the lower one collects the heated crude oil or bitumen that flows out of the formation, along with any water from the condensation of injected steam.

This report entails the detailed study of the above processes along with four case analyses. Different scenarios involving the use of these techniques are extensively studied under expert guidance. Cases are included that have been researched regarding the implementation of different strategies of MEOR and SAGD as their principal processes.

ACKNOWLEDGEMENT

We take this chance to express our heartfelt gratitude to all those who helped us to successfully complete our project ***"Comparitive Analysis of the Techniques of Microbial Enhanced Oil Recovery (MEOR) and Steam Assisted Gravity Drainage (SAGD) for the Production Enhancement of a Field".***

Firstly we would like to thank our mentor and project guide, **Mr.Pawan Kr.Mandappka** for helping us out in understanding the case studies included. Without him this project would not have been possible. We would also like to thank **Prof. Arun Chandel** for his support and encouragement all throughout the project.

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1.1 Project Background

As compared to what the primary and the secondary recoveries offer, the concept of tertiary recovery is a boon for the economics of reservoir exploitation. The self descriptive term of Enhanced Oil Recovery (EOR) methods has gained a significant boost in the industry practices for extracting more of the remaining residual hydrocarbon, than what is left after primary and secondary recovery processes. Figuratively, 20-30% of the recovery is obtained from the conventional and natural drives. However, an alternative supplement to enhance the recovery is provided by EOR processes which lead to the recovery efficiencies of 30-70% of the reserve.

EOR techniques could be divided as follows:

1. Thermal EOR methods include cyclic steam and hot water injection.
2. Microbial Injection injection of microbial culture/derived products into the reservoir leads to alteration of properties of the fluid interactions in favour of enhanced recovery.
3. Chemical The injection of various chemicals, usually as dilute solutions, have been used to improve oil recovery. Injection of alkaline or caustic solutions into reservoirs with oil that has organic acids naturally occurring in the oil will result in the production of soap that may lower the interfacial tension enough to increase production
4. Gas Injection Most common is the application of CO2 to recover the reserves in an economical manner. The method is an proficient electricity consuming method.

The strategy behind MEOR (Microbial Enhanced Oil Recovery) is injection of microbe with suitable nutrients which produce their metabolic products like gases, surfactants, acids etc or extracellular product of metabolism may be extracted from cultures grown at the surface and solutions of these materials may be injected into the Petroleum reservoir that can aid in releasing oil from the reservoir rock. Certain species of microorganisms can be manipulated and controlled to release trapped oil in significant and economic quantities. Some microbial methods aid inn paraffin removal while others are designed to modify heavy oil. Still other micro-organisms produce chemicals, such as surfactants, polymers, or solvents that are useful in oil recovery processes, either in above ground facilities or in situ.

SAGD (Steam Assisted Gravity Drainage) is an advanced form of steam stimulation in which a pair of horizontal wells are drilled into the oil reservoir, one a few meters above the other. Low pressure steam is continuously injected into the upper wellbore to heat the oil and reduce its viscosity, causing the heated oil to drain into the lower wellbore, where it is pumped out. The upper well injects steam, possibly mixed with solvents, and the lower one collects the heated crude oil or bitumen that flows out of the formation, along with any water from the condensation of injected steam.

1.2 Project Aim:

To illuminate the techniques of MEOR and SAGD by the detailed analysis of a MEOR Pilot Test carried out in Argentina Pieodras Field, a complete MEOR job by Oil India Limited (OIL) in the Barail 3rd and 4th sand of Tipam horizon in the year 2005 & 2008. An attempt for the comparison of both techniques based on their respective 3-D Numerical simulation models was also made.

1.3 Project Objective

To expand the knowledge base of the author regarding both the techniques, along with the extensive analysis of their application in different fields and conditions.

A Microbial Enhanced Oil Recovery (MEOR) job done by Oil India Limited (OIL) in Barail 3rd and 4th Sand was studied extensively to determine the net oil gain by the application of the bacterial consortium. Also 3-D Numerical simulation of MEOR technique was sought to for understanding the mathematical modelling of the process and the effect of the various reservoir parameters affecting the action of microbes.

SAGD numerical simulation was analysed to define the variation of the production rate with the different methods of performing the operation.

1.4 Project Scope

This report entails the detailed study of the above processes along with a comparative study of both on various grounds. Different scenarios involving the use of these techniques are extensively studied under expert guidance. Case studies that facilitate the analysis of both the techniques under given reservoir conditions have also been dealt with.

1.5 Project Methodology

An extensive theoretical study of both the techniques was collected and studied for around 3 months. Further the data of the MEOR and SAGD simulation run was gathered from the experts and a study for the feasibility of the run was done. The equations involved and the results of the simulator runs provided by the expert guide were analysed and studied for their respective inferences.

The MEOR job of OIL was analysed for the post and pre production data. The production behaviour of the field was plotted with respect to various alterations in the given data.

Finally, the comparison of the techniques was performed based on the fields worked upon, challenges in each and their limitations. The total cost analysis of the OIL project was also reviewed.

1.6 Project Limitations:

Due to the limited authorised literature available for both the techniques, the best attempt was made for as elaborative study as possible.

Due to the absence of any unsolved numerical problems available for either of the techniques, those provided by the mentor were studied to the best possible extent, with as many numerical variations as possible.

The expertise gained in the techniques is purely based on the hands on experience gained by working on the field. After understanding the basic principles of the methods, the best possible interpretations by the author was attempted to achieve the aim of the current project.

Chapter 2: Literature Review

2.1 MEOR:

The primary aim of MEOR is to increase the production percentage from a particular field with increased economic benefits. The technology is in itself a combination of ideas from various subjects such as geology, chemistry, microbiology, petroleum engineering, environmental engineering and chemical engineering.

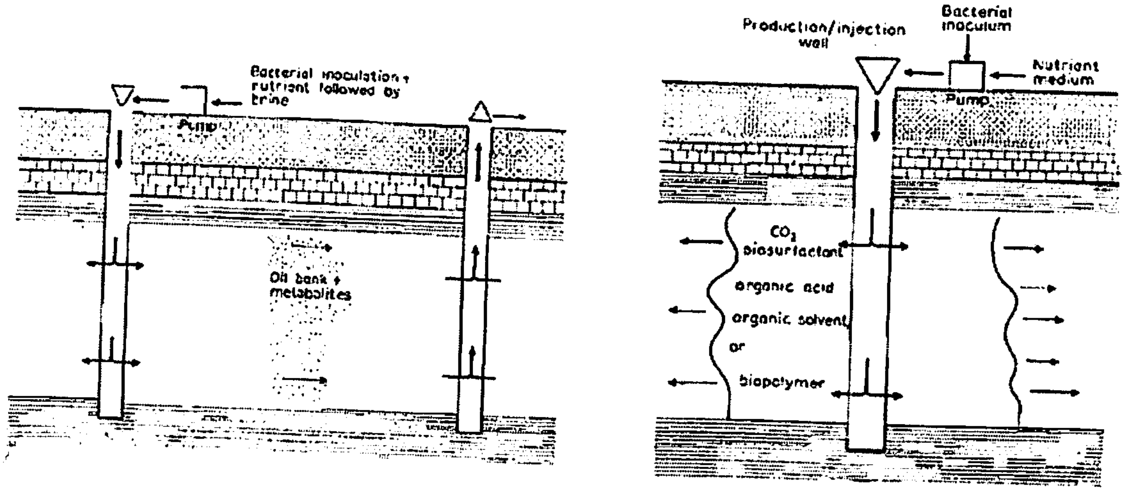


Figure 1 ***Some techniques of applying bacteria to improve reservoir recovery***

(Source: Donaldson Erle and Chillingarian George, 1989, Enhanced Oil Recovery, Processes and Operations)

Microbial cultures synthesize a large variety of biochemical products from crude oil constituents. These are produced when the cultures are provided with proper essential nutrients and environmental conditions. The range of metabolic products generated from the microbial attack of petroleum is very broad.

Table 1 Range of metabolic products generated from the microbial attack of petroleum

Bioproduct	Effect
Acids	• Modification of reservoir rock • Improvement of porosity and permeability • Reaction with calcareous rock and CO_2 production
Biomass	• Selective and nonselective plugging • Emulsification through adherence to hydrocarbons • Modification of solid surfaces • Degradation and alteration of oil • Reduction of oil viscosity and oil pour point • Desulfurization of oil
Gases (CO_2, CH_4, H_2)	• Reservoir repressurization • Oil swelling • Viscosity reduction • Increase of permeability due to solubilization of carbonate rocks by CO_2
Solvents	• Dissolving of oil
Surface-active agents	• Lowering of interfacial tension • Emulsification
Polymers	• Mobility control • Selective and non-selective plugging

The oil produced from the MEOR technique is commonly termed as "incremental oil" i.e. the oil that was "*not supposed to be recovered*". A better translation of the phrase could be in the form that, after the primary and secondary recoveries, more than 60%-70% of reserves

remain untapped. Therefore, if MEOR methods, or in general the EOR methods were not invented, this untapped oil could never be recovered.

2.1.1 Geobiology and MEOR

MEOR involves stimulating indigenous reservoir microbes or injecting naturally occurring bacteria into the reservoir to produce specific metabolic products or perform specific metabolic products to improve mobility ratio of the reservoir fluids or to induce preferential plugging of pore spaces to facilitate a better directional distribution of sweeping fluids. MEOR can also involve injection of with microbially made agents produced ex situ by traditionally fermentation approaches. The selection of appropriate organism and their activities are on dependent of the environmental conditions in the reservoir under consideration.

The whole concept of MEOR can be divided into three parts:

1. Biology
2. Geology and mineralogy
3. Fluids

The first component, biology, is the manipulator, through which the beneficial changes in the fluids may be achieved.

Any significant beneficial changes due to biological activity introduced into the geological and mineralogical component are limited, with the exception of some minor digenetic changes in the mineral component.

Fluids, the third component of the system, can be subjectto manipulation. The effects of meor can be felt by altering the relative viscosities of the oil water system, changes in the interfacial tension between water and oil, the composition of the aqueous phase and, to some extent the composition of oil phase.

2.1.2 In-Situ Microbial Enhance Oil Recovery

The alteration styles discussed above could be well classified in 3 major type:

1. IFT Reduction.
2. Selective Plugging.
3. Mobility Ratio Enhancement.

2.1.3 Interfacial tension

The reasons leading to chemically or biologically enhanced oil recovery using bacterially produced surfactants are obvious from the following **situational example:**

In water-wetted reservoirs, a substantial amount of the residual oil is located in the form of individual droplets and ganglions. Considering a droplet of oil residing in a pore throat 0.4 mm long with end curvatures of R1=9×10-3 mm and R2= 4 ×10-2 mm, respectively, the water-oil interfacial tension, σ, being 30 mN m-1, the pressure difference Δp can be determined using Laplace's equation.

The differential Δp required to move this oil droplet through its limiting pore would be 1-3 MPa. The practical limits achievable in the field are usually in the range of 20-30 ×10-3 MPa. This example indicates clearly the necessity for an ultra-low interfacial tension of less than 10-2 mNm-1 to be achieved by the introduction of a surfactant, to obtain a significant enhancement in recovery.

The following criteria have to be satisfied t0 achieve a displacement of residual oil:

i. The surfactant employed has to be capable of mobilizing residual oil
ii. An optimal mobility relationship between the crude oil and the aqueous phase must be satisfied.
iii. The ability to displace oil must be maintained as the surfactant progresses from the injection point or the location of its biological production to the production well.
iv. Since the amount of surfactant produced by an organism is finite in its concentration, consideration must be given to mechanisms rendering it ineffective.

The major ones are:

i. Surfactant retention by the porous matrix.
ii. Dilution of the surfactant by the reservoir fluids.
iii. Partitioning of the surfactants between the oil and the aqueous phase.

iv. Biological degradation.

There is probably no single surfactant which would work satisfactorily in all reservoirs. This is simply because the operational situation varies from reservoir to reservoir, depending on the geological, mineralogical, and chemical characteristics of the reservoir, its physical parameters, and the physicochemical composition of the reservoir fluids.

2.1.4 Surfactants

They can be divided into the following categories:

Anionic	: containing carboxylic acids
Amphoteric	: represented by amino acids and peptides.
Non-ionic	: like esters.
Cationic	: including amines and heterocycles.sa

The action of a surfactant depends on the existing reservoir conditions, which might influence or hinder the act of improvement of the mobility ratio. These factors include the composition of the crude, the colloidal chemistry and thus the presence of paraffins. The diffusion coefficient of the surfactant depends on the viscosity of the reservoir fluids. The efficiency of the anionic and amphoteric surfactants is affected by the Ca2 + and Mg2+ cations in the reservoir waters.The efficiency of the surfactants depends on the environmental conditions in the reservoir like diffusion rates from the bacterial side to the oil-water interfaces.

The efficiency of the surfactant is also affected by the lithology of the reservoir rock. Different rocks adsorb surfactant to a different degree. The ability o f clays to adsorb surfactants decreases in the following order:

Cationic

Non-ionic

Anionic compounds.

Silicates show slight adsorption of non-ionic surfactants, but adsorb strongly cationic surfactants. Therefore, cationic surfactants should not be applied to silicate-rich reservoirs. **For enhanced oil recovery, a surface adsorption of a surfactant of 0.5 ×10-4 mg cm-2 on quartz is generally considered as an acceptable level.**

Desirable characteristics of a surfactant

1. Ability to permanently lower the interfacial tension below 10^{-2} mN m-1
2.
3. Solubility or at least dispersibility in highly saline reservoir waters.
4. Low adsorption coefficient relative to the reservoir rock
5. Partial solubility in oil.
6. Capability of stabilizing oil-water emulsions.
7. The concentration enrichment at the oil-water interface. This leads to a biological production of a surfactant at the oil-water interface.

Techniques to monitor the MEOR

To monitor and evaluate the microbial process monitoring techniques and procedures are applied to discern microbial contributions. Among them, cell count of the particular microbes are measured at various location and timing such as incubation area, injection pump, manifold, injection wells and production wells by colony forming unit (CFU) method, followed by direct PCR method to identify particular microbe. This technique had provided insights of the microbial activities in the system including subsurface reservoir.

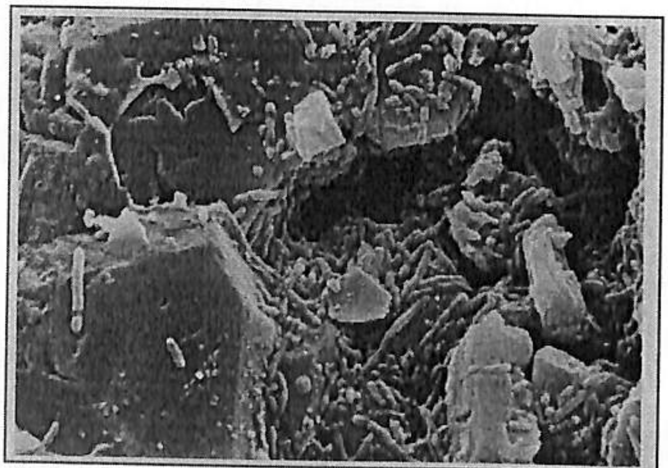


Figure 2 ***Electron micrograph of biofilm inside rock. The blocking of pores by bacteria can clearly be seen***

*(Source: **Donaldson Erle and Chillingarian George, 1989, Enhanced Oil Recovery , Processes and Operations)***

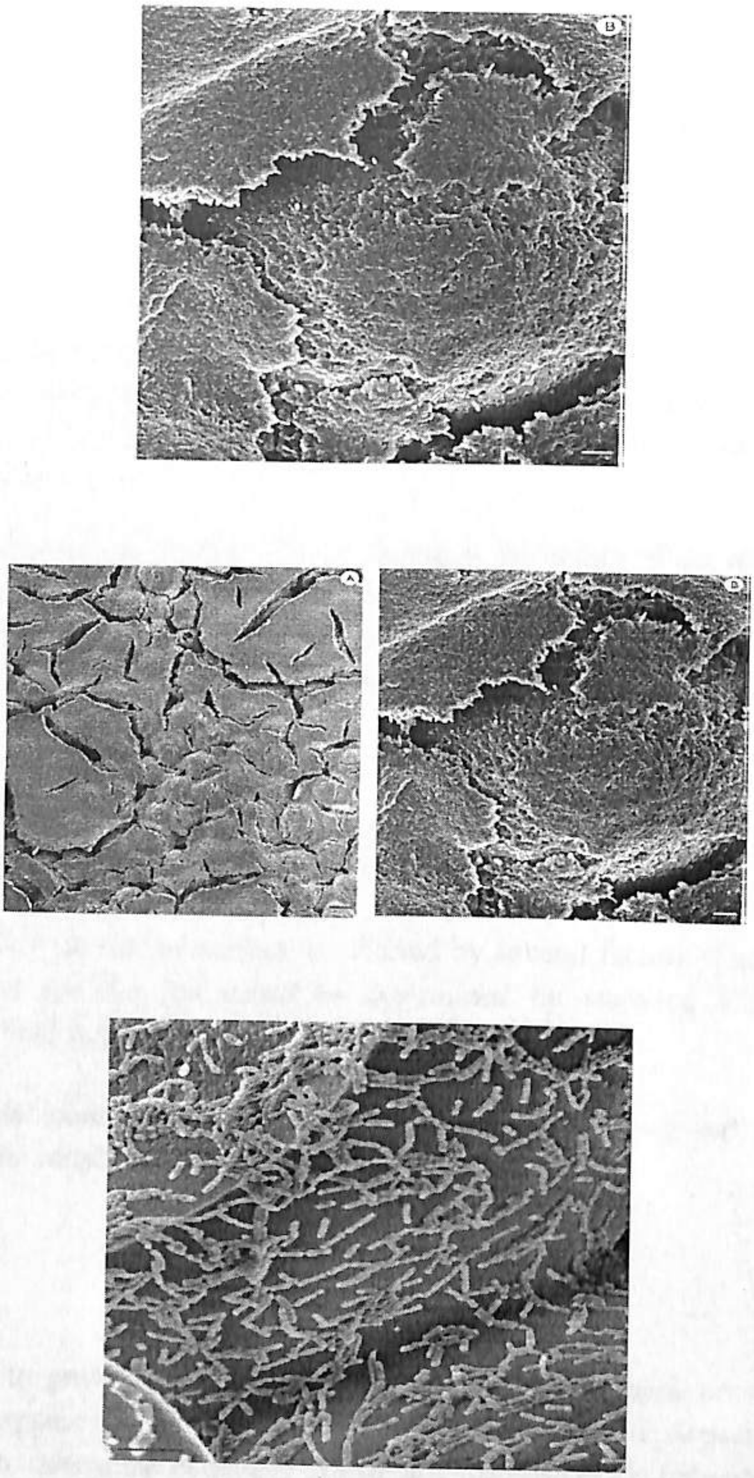


Figure 3 *High-magnification scanning electron microscope image of bacterial cells inside the model glass bead core below the filter cake. No exopolymer (slime) production is evident*

(Source: Donaldson Erle and Chillingarian George, 1989, Enhanced Oil Recovery , Processes and Operations)

2.1.4 Engineering Perspectives

It is important to understand the limitation of the reservoir under consideration. This is important as there is no one single MEOR method which could suite all the variety of the subsurface conditions.

Microbial toxicity to heavy metals increases at elevated temperature; and, heavy metals are frequently present in reservoir brines, thus the increase of temperature in the subsurface (25 oC + 18 oC/ km of depth) might inhibit the effective in situ application of microbial cultures.[1] Therefore microbes intended for use should be tested prior to injection at the surface temperature and pressure. The growth rate of microbes is reduced at high pressures. Thus the microbe culture should be tested at prevailing subsurface conditions for effective application to the job.

An essential requirement of an effective job design is the ability of the microbes to migrate deep down to the reservoir. Furthermore, the microbes must possess the capability to multiply under specific subsurface environmental conditions. This is achieved by supplying the microbes with sought after nutrients, which the oil pool is devoid of, by injecting them from surface.

2.1.5 Constraints

The microbial activity at the subsurface is affected by several factors. The suitability of the culture to be used for the job could be determined by studying these constraints in comparison to the field requirement.

Some environmental constraints that may be responsible to screen out several microbial colonies during their suitability test are:

1. <u>Pressure</u>

   The ability to grow at high pressure can be shown to depend on the energy source present, inorganic salts present, Eh, pH, and temperature. However, it is difficult in most cases to determine exactly which of these parameters is affecting growth, as they are all affects by pressure. Of particular interest with regards to oil reservoir is that salts such as NaCl, as well as divalent cations such as $Mg2+$ and $Ca2+$, which are commonly found in oil reservoirs, can confer a greater barotolerance to some marine organisms. An increase in pressure leads to an increase in gas solubilities. This has a direct affect on the reduction-oxidation potential (redox potential) of these gases. Eg hydrogen or CO2.

1. <u>pH</u>

The effect of changes in acidity or alkalinity is also seen in the cultures prepared for the injection activity. The pH not only affect the growth and metabolism directly but also in an indirect manner by affecting the solubility of toxic materials. The altered ionic regions could interact with the ionic particles and affect the motion of the cells through the porous media. At lower pH, solubility of heavy metals increases and thus their toxicity also increases. Whereas, at lower pH, some of the nutrients could precipitate and thus render themselves ineffective as a growth medium for the bacterial culture.

2. Temperature

One of the major determinants of enzymatic activity is the variation of temperature. Temperature, at different ranges could improve or harm the reaction, and this affecting the survivability of the culture. The overall optimal cellular growth or metabolism might be affected by the above. Thus the microbes could be classified according to the range of temperature that is favourable for their existence. For instance: psychrophiles (<25 °C), mesophiles (25-45 °C), thermophiles (45-60 °C) and hyperthermophiles (60-121 °C). Although such cells optimally grow in those temperature ranges there may not be a direct relationship with the production of specific metabolites.[2]

3. Pore size/geometry

According to a study, noticeable microbial response is detected in the pore size of .2um. It is expected that pore size and geometry may affect chemotaxis. However, this has not been proven at oil reservoir conditions.

4. Oxidation potential

Bacteria, basically are the prokaryotic organisms that basically exploit the anaerobic respiration technique, for their metabolism. During anaerobic respiration, Oxidation Potential is the sole driving force.

The electron transport occurs along the surface membrane. This generates a net OP which decides the favourability towards a reactions occurrence.

For instance, nitrification is hierarchically more favored than sulphate reduction. Therefore , by disallowing the production of H2S we could increase the chances of Enhanced Oil recovery.

$$SO_4^{2-} + 10H^+ + 8e^- \rightarrow H_2S + 4H_2O$$

5. Composition of the electrolyte

Electrolytes affect the water in a way by affecting its vapour pressure, autopyrolysis and thermodynamic activity. All are reduced by the introduction of electrolytes in the cell culture.

Electrolytes also promote an ionic strength gradient across cellular membrane. Therefore this provides a powerful driving force allowing the diffusion of water into or out to cells. Some microbes from hypersaline environment such as Pseudomonas species and Halococcus thrive at lower thermodynamic activity.

2.1.6 Conditions for a MEOR process:

The MEOR agents whom are to be analysed should meet the following criteria:

a. The **occurrence of gas bubbles should be avoided** as this would lead to the pore spaces getting occupied by the gas, thus in effect, reducing the permeability to the aqueous phase.

b. **No extracellular polysaccharides or exopolymers**, even if they are soluble.

c. **Size** is an important consideration. The phase should be singly dispersed.

d. Adherence tendency of the bacteria to the formation wall is a detrimental characteristic factor. This **leads to a biofilm formation** which occurs in prescence of glycocalyx. The bio film hampers the permeability largely.

2.1.7 MEOR Mechanisms

a. **Hydrocarbon Biodegradation (Crude):**
As the name suggests, the mechanism involves breaking down of crude into its different fractions. The bacteria consume the heavier fractions of the crude. This decreases the viscosity of the oil and increases its value. Pseudomonas, Arthrobacter, and other aerobic bacteria are especially effective in the degradation of crude oil.[1] This degradation, however, is limited to the fractions which are lighter such as

paraffins. Paraffins seriously obstruct the flow from the wellbore and the degradation thus serves a good purpose. [2]

b. **Gas Production:** On the interaction of the bacteria to the oil, fermentation of the carbon sources takes place, which leads to the production of certain gases such as CO_2, N_2, H_2, CH_4 etc. These improve the recovery basically by the viscosity reduction.

c. **Production of Chemicals:** Chemicals useful in the improvement of oil recovery such as organic acids, alcohols, solvents, surfactants, and polymers are produced by a wide array of microorganisms[3] .

d. **Selective Plugging:** This involves the technique of selectively blocking of highly permeable zones, such as the water channels. This water is then diverted to the non swept regions to sweep out the oil, thus increasing the recovery.

2.1.8 Classification Of Meor

While according to procedures of processes, underground MEOR is sorted as:
• Cyclic Microbial Recovery (Huff and Puff, Single Well Stimulation)
• Wax Removal and Paraffin Inhibition (Wellbore Cleanup)
• Microbial Flooding Recovery
• Selective Plugging Recovery
• Acidizing/Fracturing

2.1.9 Advantages of MEOR and Difficulties

Advantages

MEOR is a potentially attractive way to recover additional oil from a reservoir.

1. Economically attractive for marginally producing oil fields, a suitable alternative before the abandonment of marginal wells.
2. It can be applied to a wide range of crude oil (i. e. heavy oil and light oils).
3. Microbes can be selected and adapted for specific reservoir conditions [4]
4. MEOR products are all biodegradable and will not be accumulated in the environments.
5. They help reduce paraffin related operational problems
6. Easily applied with typical surface equipment for waterflooding.
7. The cost of microbial injection fluid is relatively low and not dependant on the price of crude oil

8. The injected bacteria and nutrients are inexpensive and not dependant on the price of the crude oil and easy to obtain and handle in the field.
9. Microbial activity can be stopped by discontinuing injection of nutrients.

Disadvantages and difficulties

One of the major hindrances is the availability of organisms that could prove viable under extreme conditions that exist in the reservoir. MEOR is unlikely to replace completely conventional EOR methods.

Sometimes the MEOR performance is not steady. The achievable yields would be lower because the microbiology in the reservoir would not be controllable to achieve sustained surfactant production. Losses of biosurfactants by adsorption to reservoir rocks and in situ biodegradation would further limit performance [5]

Some of the following difficulties have been recently encountered in spreading the MEOR technology:

1. The MEoR technology has nt been combined firmly with oil reservoir engineering.

2. Attentions are not thoroughly paid to study on MEOR mechanisms, especially the influence of each factor in the process on oil recovery effects.

3. The optimization of techniques of field tests is very difficult. The field test blocks are usually in the late stage of oil recovery, and the underground geological conditions get so complicated that the laboratory simulation is very hard.

4. There is still uniform development program for MEOR. Each domestic oil field formulates its own Development Orientation according to the oil reservoir conditions and exploiting situation.

5. Unlike the other EOR technology, there is shortage of integrated facilities and techniques for MEOR.

6. There lack enough recognition of MEOR. To achieve good results with a short time, some pilot tests were conducted without thorough inspection and examination on the oil reservoir, and this will influence the ultimate recovery effects.

2.2 Steam Assisted Gravity Drainage (SAGD)

The requirement of a technique to unlock the bitumen trapped at shallow depths with very high viscosities is the basic driving force for the entire R&D in the oil industry. The oil trapped at shallow depths, i.e. those which are extractable through surface mining, requires a technique that is gentle enough (this means a technique which can be carried out at low pressures) along with being able to mobilise the bitumen. Steam Assisted Gravity Drainage (SAGD) has been proved to fulfil such requirements and thus has been researched on the basis of numerical, analytical and field application grounds.

2.2.1 A Bit of History

Roger Butler, from Imperial Oil, has been credited with the invention of SAGD. He later on analysed the economic feasibility of the method. During the project of Cold Lake in Alberta, 1978, the first application of SAGD was used, where a horizontal well was assisted with a vertical steam injection profile.

2.2.2 The Reason for Interest in SAGD

The first commercially applied process to recover trapped heavy oil was Cyclic Steam Stimulation (CSS). The process is also known as "huff and puff". Steam is injected usually at a pressure greater than the fracture pressure, through a vertical well for some time. Then the steam is allowed to "soak" in for some time by shutting down the well. Later, the well is opened and allowed to produce heated oil and steam condensate until the production rate declines. The whole process is repeated several times, which leads to the development of a "steam chamber" that is expanding. The oil gets drained from the void spaces of the chamber, is produced, and then is replaced with steam. Newly injected steam moves to the boundary of the chamber, after entering through the pores, and heats the cold oil present at the boundaries of the chamber.

However, there are problems associated with this process.

I. The fracture tends to occur vertically.
II. The steam chamber is narrow because the steam injected moves through the fractures and heats outwardly there from.
III. This results in the occurrence of large bodies of unheated oil extending between adjacent wells and their linearly extending chambers.
IV. The SOR is higher as the steam is free to be driven off any permeable path that is available.

Thus, the CSS has lower steam utilisation efficiency and lower production enhancement efficiency. Due to the above limitations, and some other prominent drawbacks, a new process of Steam Assisted Gravity Drainage (SAGD) was introduced.

2.2.3 Steam Assisted Gravity Drainage: How it is done

The process consists of a pair of horizontal wells, or a series of vertical wells that inject steam directly above a horizontal producer. The main principle underlying the process is of viscosity reduction and thus, mobility enhancement. The injected steam forms a steam chamber, at the periphery of which the steam condenses and releases the latent heat. This in turn results in the reduction in viscosity of the crude, thus mobilising it. The next step involves the role of gravity, due to which the mobilized crude flows down to the production well at the bottom of the steam chamber. Uniform development of the steam chamber is one of the major challenges of the SAGD process. This is because the steam chamber can propagate both in axial and longitudinal directions very rapidly.

The process occurs in 3 phases:

1. Startup, or circulation;
2. Normal SAGD operation
3. Wind down.

The objective of the startup is to mobilize the bitumen between the injector and producer. This is done to establish communication between the wells. Most widely, startup is conducted by circulating steam in both the wells for approximately 90 days. However, Normal operation comprises of injecting steam and producing bitumen to form the "steam chamber" above the pair of wells. This results in gaining access to the maximum amount of resources in an area. This phase lasts as many years as necessary. The maximum amount of oil is recovered from the drainage volume during the Normal phase of steam injection. Finally, the wind down includes a series of operations aimed at reducing the amount of steam injected. Further, auxiliary operating patterns are used to maximize recovery.

A detailed description of the above steps is presented as follows:

1. A pair of coextensive horizontal wells placed above one another (6-8m) is used. The wells are located to the base of the formation.

2. The span of formation between the wells is heated. This is done to mobilize the oil contained in that region. The heating is done by passing steam through each of the wells, thus developing a pair of "hot fingers".

3. When the span is sufficiently heated so that the oil can be driven to either wells for production, the communication between the wells has been established. The steam circulation is further terminated.

4. Steam injection at a pressure less than the formation fracture pressure is initiated through the upper well, and the lower well is opened for drainage of mobilised oil. The appearance of steam at the production end shows that the communication between the wells has been established.

5. Now the SAGD process is applied to recover the trapped oil. The production well is throttled, to maintain the steam trapped conditions. Throttling is used to keep the temperature of the liquid at around 6-10 degrees Celsius below the saturation steam temperature at the production well.

6. As the steam is injected it rises up and contacts the crude above the upper injection well.

7. The steam gives up heat, condenses, whereas the oil absorbs the heat, and becomes mobile as its viscosity is reduced.

8. The condensate and the heated oil drain downwards to the lower injection well from where it is produced.
9. The heat exchange takes place at the surface of an upwardly extending steam chamber.

10. The chamber continues to expand upwardly and laterally until it contacts the impermeable overburden lying above.

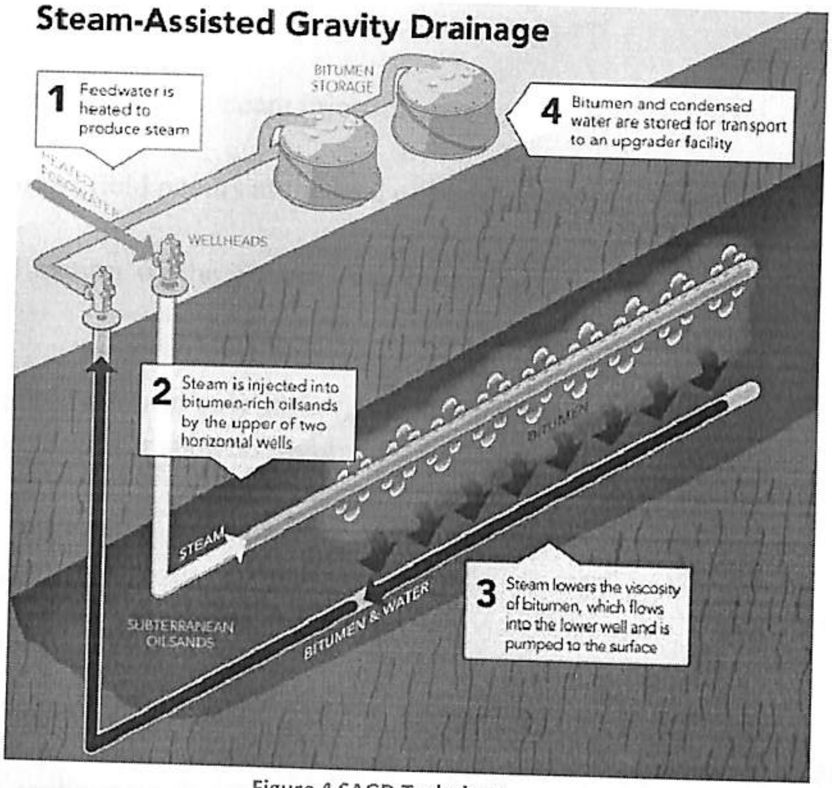


Figure 4 SAGD Technique

One of the main characteristics of the process is the Steam Trap technique. While the injection, and the production of the fluids, it is important to control their temperature. This prevents the steam from flowing together with them. The temperature of the steam, as explained above, is kept a few degrees below the steam saturation temperature which facilitates the localisation of the steam in the steam chamber to the maximum extent.

2.2.4 Process Characteristics

1. Pressure at the steam chamber is constant.
2. The steam and water are condensed together along with the gas in the solution, thus helping in maintaining pressures around the producing well around desired levels. A similar assistance is provided by the thermal expansion.
3. The growth of the steam chamber is proportional to the production level; as the production increases, more pores are emptied of the oil, and thus the steam occupies them, allowing for a greater level of fusion into the immobile oil.

4. The maximum production rate is normally achieved when the steam chamber reaches the top of the formation.

5. Oil rate is not affected by steam injection rate.

6. The drain of the field occurs at the heel of both the wells.

7. The main function of the Steam Trap control is to prevent the production of live steam.

8. The main application is only in horizontal wells, as in vertical wells, low flow rates would be obtained for such configuration.

2.2.5 Types of SAGD

Each pilot program of SAGD has evolved new findings and discoveries that allow for the betterment of the techniques involved in the process. Every new experience helps in diversifying the application of SAGD in different oil fields. The patenting of new types of SAGD has been based on:

i. The way of accessing the zones of interest.
ii. The way of drilling the wells
iii. The number of wells to be drilled.
iv. The location of the wells
v. The combination of the wells
vi. The way of injecting steam.

The different types of SAGD approaches are:

1. Shaft and Tunnel Access:
   This is based on the way in which the wells are drilled, i.e. the drilling is underground and mining is used to reach the zone of interest. This type of SAGD approach can be used at shallow wells application, containing high viscosity crudes. Here, a tunnel is built while drilling, and horizontal wells reach out to the formation layers from this tunnel.

2. Access and Drilling from Surface (SAC-SAGD)
   Most commonly used configuration. This solves the problem of accessing deep reservoirs where mining is neither possible nor profitable.

3. Single Well SAGD (SW-SAGD)

   This is contrary to SAC-SAGD as it uses single well to inject steam as well as to produce oil. One of the most advanced techniques of steam application; it involves the use of coiled tubing in a very innovative way. A CT is introduced in the well and from the *toe* of the tubing, steam is released through various pores in it. The condensed hot water and steam returns to the vertical section of the well, the heel. The remaining steam heats up the oil normally, reduces its viscosity and leads it to drain through the annular, from where it is produced through another tubing.

   The main application of SW-SAGD could be in thin formations where it is not possible to insert a pair of wells. Due to the usage of only a single well, the initial capital investment in SW-SAGD is reduced to almost half.

4. Multi-Drain SAGD

   The name is derived from the use of multiple wells to drain the oil (3-9). This configuration is the most recent. Here several horizontal wells are drilled and connected to a central vertical well. The horizontals are used for steam injection and the vertical collects the heated oil and is used for production.

5. Vertical – Horizontal Well Combination

   Opposite of the above, two horizontal wells and a single vertical well can be used in combination, where the horizontals are used for production and the vertical is used for injection.

   This can be applied to very thick formations, but with a less viscous crude oil and possible a gas layer.

6. Fast-SAGD

   This approach is used to produce the same amount of oil with half of the wells and 30% less steam. This technique uses the combination of Cyclic Steam Injection in combination with the conventional SAGD. It involves a horizontal auxiliary well along with the conventional horizontal well, but at some distance from it.

7. ESAGD (Enhanced SAGD)

   Here no additional wells or alternation of wells is used. Enhancement of the SAGD process is achieved by the creation of a pressure differential between the steam chambers that have been previously set under SAGD operations. This small ΔP between the chambers helps in the steam thrusting component to enhance the recovery.

   The pressure differential can be created by lowering the pressure of the injection in one of the wells.

2.2.6 Advantages:

1. The SAGD process is a lower pressure injection process. This takes care of the problem of fracturing and steam leakage.

2. This helps in keeping the steam localised and thus better heating efficiency.
3. Steam trap control minimises the short circuiting of the steam in the production well.

4. The steam chambers produced in the SAGD process are wider than the fractures or those that are produced by the "huff and puff" process. Thus better recoveries and improved SOR is obtained by SAGD.

2.2.7 Reservoir Screening Criteria:

The performance of a SAGD project heavily relies on the choice of the field in the initial phase of the project. Determination of the proper oil base, and the possible recovery factors through the wells, could assist in making the project beneficial and economically advantageous.

Some of the screening criteria to be kept in mind during the selection of a field for the application of SAGD techniques are as follows:

1. Most SAGD projects could be applied to shallow, unconsolidated sandstone reservoirs with high permeability.

2. The most critical factor for a SAGD project performance could be Resource Quality. Oil saturation, porosity, net-pay thickness are the essential properties for determining the reserve base and forecasting recovery factors for the shortlisted basins.

3. Vertical permeability can also majorly influence the recovery. For example, if there is a shale layer present between the injector and producers, it can hamper the rise of the steam chamber and the communication between the well pairs.

4. A special contribution of overburden or caprock in a SAGD project performance can be thought upon as an essential parameter. The cap rock must provide a barrier to prevent the loss of the steam to the shallower strata, and in extreme cases, to the surface. The geo mechanical competence of the cap rock must be carefully analysed and assessed. If the leakage of steam occurs due to the failure of the cap rock to prevent it, it could heavily damage the environment and might lead to a major accident. The expansion of the steam chamber can also be affected if the steam leaks to the shallower strata, thus hampering the thermal efficiency and the ultimate

recovery. The presence of top or bottom water and/or gas caps must also be considered in the SAGD development plan. Ongoing research is helping to clarify the role of such interfaces in affecting the recoveries.

2.2.8 Well Construction

The commercial implementation of SAGD has been facilitated majorly by the evolution of Directional Drilling technology. Two parallel horizontal wells are drilled to depths between 90 and 600 m, with 4 to 7 m of vertical offset and up to 1000 m of horizontal displacement, and due to their shallow vertical depths, some of these wells require slant drilling from the surface. Typically the production well is drilled first. It is placed as close as possible to the bottom of the reservoir. The first SAGD well pair was drilled using magnetic-ranging/-guidance technology. This technology is used for the measurement of the relative position of one well with respect to another. It determines the distance and orientation from the well being drilled (injector) to the reference well (producer). SAGD wells must be designed to suite the harsh environment. The integrity and stability of the wells must be in combination with the effort for reduction of the capital cost. The intermediate casing is the main barrier which helps to isolate the underground environment for SAGD applications, and the quality of liners and its integration is primary for sand control. Therefore, the selection of adequate cement for thermal conditions and proper thermal casing design are critical. The industry is still in an evaluation phase, and different completion configurations are being implemented. The general trend is to allow for steam injection or bitumen production at two or more points along the horizontal bore. Some of the typical completion designs are dual parallel, or concentric, strings with tubing and annulus flow paths. Slotted liners are the most widely used sand-control method. Standalone screens a distant second.

2.2.9 Production Operations and Control

SAGD operations require close monitoring strategies aimed at controlling the downhole process. The control is essential to avoid operational issues and maximize efficiency and recovery.

Temperature Monitoring:
The producer wells have temperature measuring devices attached to the wellbore. Thermocouples are the preferred choice because of their reliability and lower cost. However, fibre-optic technology has been field tested widely, and implemented as well.

The main objective of temperature monitoring in the producer wells is steam-trap control.. The steam/liquid interface is maintained by the temperature monitoring process. This is achieved by creating a substantial difference between the producer bottomhole temperature and the saturated-steam temperature at the bottomhole pressure of the injector to maintain a balance that keeps the interface between the two wells intact and stable.

An optimum SAGD process involves the complete dissolution of the steam chamber, which if not dissolved, would lead to the accumulation of the steam over the producer. This could lead to a reduction of flow rate, but prevention of steam occurrence at the surface leads to a safer production process which otherwise could be jeopardised.

Pressure Monitoring

The producers are governed by fibre optic gauges, pressure monitoring gauges, open annulus gauges, bubble tubes etc. Monitoring of the steam chamber growth is the most essential task to diagnose the recovery problems.

The following methods are combined to estimate steam-chamber growth:

1. Fully instrumented vertical observation wells along the horizontals
2. Surface-deformation measurement technologies are used.
3. Seismic methods
4. Production history matching

During the initial SAGD operation phase, most projects operate at pressures that are high enough to use steam. The use of gas lift for SAGD has features which have to be taken care of to assure proper success. As the SAGD project matures, the tendency is to operate at lower chamber pressure, which requires different artificial-lift methods.

2.2.10 Performance and Challenges

There are different evaluation methods for SAGD performance. However, to benchmark project efficiency, a key parameter is the SOR. SOR indicates the volume of steam required to produce a certain amount of oil. The main aim is to minimize the ratio, where values in the 2.0 to 3.5 range are considered as good performance.

Other performance indicators are bitumen production rates and recovery factors. The average bitumen production per well pair in the industry is between 400 and 1000 BPD with ultimate recovery factors higher than 50%.

The trend for most commercial projects is to increase the thermal efficiency and recovery of bitumen of the process SAGD variations, such as nonparallel-well geometrical configurations, additional wells, solvent injection, steam-distribution optimization, and inflow control.

Despite the successful commercial implementation of SAGD technology, there are still two major challenges that have to be overcome;

1. Dependence on natural gas
2. Environmental impact.

Currently, most of the projects rely on natural gas for the production of steam. Two major drawbacks associated with the use of NG as a source of steam is that the prices of NG are very volatile and also the availability is uncertain. Therefore, the success of a SAGD project, greatly depends on the above two factors. Finally, the carbon footprint and water requirements in SAGD are quite substantial due to the steam generation.
To minimize the environmental impact of SAGD, cogeneration, brackish-water use, water recycling, and other enhancements are being considered.

Chapter 3: CASE ANALYSIS

3.1 CASE I: MEOR Pilot test in Pieodras Field, Argentina

Pilot testing of the project allows the identification of potential problems before they become costly mistakes. Involving all the conditions that are to be encountered during the actual project life, pilot testing is performed to detect and diagnose the potential downhole or surface problems that might occur due to the varying parameters and time. MEOR projects involve a great deal of uncertainty both in economic as well as performance terms. Thus a pre test run is essential to evaluate the risks and potential problems that might evolve later in the life of the process.

3.1.1 Pieodras Colorados Oil Field, Argentina.

Inoculation process is carried out in six producer wells. Out of them, 2 are horizontal. A complete set of rheology parameters and biochemical fingerprints is used to evaluate the compositional difference in the pre and the post job fluids. Incremental Oil averages 66% over baseline with minimum values of 28.5% and maximum above 110%. Results are consistent because they show a clear correlation between treatment design modifications and water cut reduction. This correlation thus proves that Microbial Enhanced Oil Recovery methods are controllable and predictable if team integration and proper engineering methods are observed during pilot design and well monitoring stages.

Cost per Incremental Barrel (CIB) was 5 $/barrel during pilot stage. On MEOR Expanded scales, this value is forecast to decrease to below 2 $/barrel. The project demonstrates that MEOR is cost effective, easy to implement and complies well with local environmental regulations and biosafety issues. This pilot program is the first part of an integral mid-term strategy to use biotechnology in paraffinic oil bearing reservoirs.

3.1.2 Introduction

Two main productive formations are worked upon in the field. The objective of these trials is to determine project performance in terms of fractional flow evolution and its correlation with well completion and reservoir petrophysical parameters. By the use of experimental design techniques, associated objectives are achieved to determine how predictable and controllable this technology is based on previous screening criteria and monitoring routines.

3.1.3 Field Description:

Discovered : 1953

Production Initiation : 1956

2 separate reservoirs : Conglomerdo Rojo Inferio (CRI) (Barrancas Fm)
Victor Oscuro Member (Rio Blanco Fm)

The first one accounts for 80% of the total production.

Production : 430m3/d
No. Of Wells : 85 active wells
Average Production per well : 5.8 m3/D
Active wells are grouped in 4 batteries.
24 are horizontal.
80% of the Piedras production comes from 38% of its wells

Waterflooding Data:
Incipient, with 6 wells injecting 1100 m3/d.

Candidate Well: Producers from only one reservoir, avoiding treatment of multilayer systems.

3.1.4 The Job

The effect of microbial activity being positively induced in the subsurface is detected in two ways:

1. <u>The clean up effects:</u> This is due to the removal of damaged organic zones near the perforated area of the well. The clean up leads to an increased permeability, thus spiking the oil rate, for a short time period.

2. <u>The Rheological Effects:</u> This is basically due to the compositional alterations occurring at a deeper colonization radius. This effect is the most important MEOR objective as this improvement is sustainable for a long period of time if proper inoculation is carried out.

The proof of the above rheological studies is carried out during the lab study in combination with the organic geochemistry models.

3.1.5 General Screening Criteria

Primary Requirements to check:

1. Crude oil composition must contain n-alkanes in sufficient amount and show no evidence of previous biodegradation.

Table 2 Pristane/Phytane concentration in Piodras Colorados oil

Well	Pristane/nC-17	Phytane/nC-18	Obs.
PC-1022	0.22	0.13	Rio Blanco Fm. (P. Coloradas)
PC-19	0.26	0.14	Barrancas Fm. (P. Coloradas)
LL-7	*5.02*	*13.51*	Llancanelo (extremely biodegrated oil)

Table 06: MEOR. Natural biodegration status in Piedras Coloradas oils

2. Bottomhole temperatures should be to be less than 250 °F. *Pressure is not a limiting factor.*

3. Chlorides < 100,000 ppm in the formation water.

4. PH is best near neutral

5. Pore throat distribution in objective reservoirs needs to have a minimal portion above the range of microbial community size to permit microorganism migration. This requirement means to have an "available window" poral geometry to permit profound microbial incursion

Pore throat distributions and the pore structures of the two reservoirs under consideration

3.1.6 Fluid Evaluation (Oil)

PVT data

Bubble pressure (psi)	:	1023
GOR (M3/M3)	:	37
Bo factor (M3/M3)	:	1.176
Viscosity	:	4.5
API°	:	32

Geochemical background

Geochemical Analyses were performed on five oils from Piedras Coloradas field

- All five oils belong to one family

- The oils show no signs of water washing or biodegradation

All are very paraffinic oils that were sourced from a single source facies

- All geochemical parameters indicate a single oil type, with normal alkane distributions

- Pristane/Phytane ratios and carbon isotope ratios are particularly diagnostic oil-oil correlation parameter

3.1.7 Rheological Studies

Conceptual Basis

Oil as very complex substance exhibits typical non-Newtonian behaviour. Viscosity is shear rate sensitive and it correlates strongly with the fluid dynamics occurring in the poral space. The concept of constant viscosity in the drainage area is no longer valid, rather "apparent" values are used.

Specific quantitative lab procedures are carried out to measure the change in rheological properties in treated i.e. inoculated and untreated i.e. control samples obtained from well head manifold for every candidate.

Lab Indexes and Methodology

To determine the alterability of Barrancas and Rio Blanco oils under systematic microbial influence (enzymatic cracking), serial assays are conducted. Lab procedures consisted of a series of inoculations of oil with seven different microbial products, followed with 48 to 96 hours of controlled atmosphere incubation at specific temperatures.

Deviations in μ_{app} vs. Temperature [°F] and μ_{app} vs. Shear Rate [1/s] curves were the basis for calculating quantitative numbers which described the degree of compositional alteration. These numbers translate the graphical information into lab performance indicators. Furthermore, they are used during pilot monitoring to contrast and compare lab and field figures.

i) The **Newtonian Index (NI)** is used to evaluate the shifting from shear rate sensitive (pseudoplastic) behaviour toward a more Newtonian fluid.

$$NI := \left[\left[\frac{\left[\left(\mu app^{control}\right)^{minSR} - \left(\mu app^{control}\right)^{maxSR}\right]}{\left(\mu app^{inoculated}\right)^{minSR} - \left(\mu app^{inoculated}\right)^{maxSR}}\right]\right]^{TMD}$$

The comparison between control and inoculated oil samples is evidence of microbial cracking by each different culture. **To test as positive, NI needs to be greater than 1.10.**

ii) **The Delta Viscosity (DV) Index** is used to measure the global change in viscosity in the explored range of shear rates. **To test as positive DV need to be greater than 0.10.**

$$DV := \left[\frac{\sum_{i=minSR}^{maxSR}\left(\mu app_i\right)^{control} - \sum_{i=minSR}^{maxSR}\left(\mu app_i\right)^{inoculated}}{\sum_{i=minSR}^{maxSR}\left(\mu app_i\right)^{control}}\right]^{TMD}$$

iii) A simple version of Enhanced Oil Recovery factor (EOR Index) is obtained, by direct mathematical manipulation of DV index, as related only to viscosity contribution. **An exceeding EOR value from 1.15 tests as positive**

$$EOR := \frac{1}{(1 - DV)}$$

Application of the above was carried out in the project. A data base of <u>84 oil samples from 11 different fields</u> (22 from P.C. area), pertaining to the same sector of Cuyo sedimentary basin were tested to define general rheological properties of Mendoza North. First evaluations began on 1994. In general all these crude oils tested far above cut-off values, <u>evidencing very good microbial treatability</u>. The values in pre-selected wells were:

Sample	NI	DV	EOR
PC-1020 (Horizontal, V.O.)	1.64	0.38	1.61
PC-1022 (Horizontal, V.O.)	4.44	0.39	1.64
PC-86 (Vertical, V.O.)	20.8	0.76	4.13
PC-94 (Vertical, V.O.)	0.27	0.61	2.60
PC-19 (Vertical, C.R.I.)	13.50	0.39	1.64
PC-68 (Vertical, C.R.I.)	1.57	0.95	20.89
Limit for positive testing	>1.10	>0.10	>1.15

3.1.8 Reservoir Characterisation

I. Barrancas Fm. (C.R.I.)

Poral geometry: Core testing using micro porosity and capillary pressures converted into poral throat distribution show very large pore system with average values of 50 μm

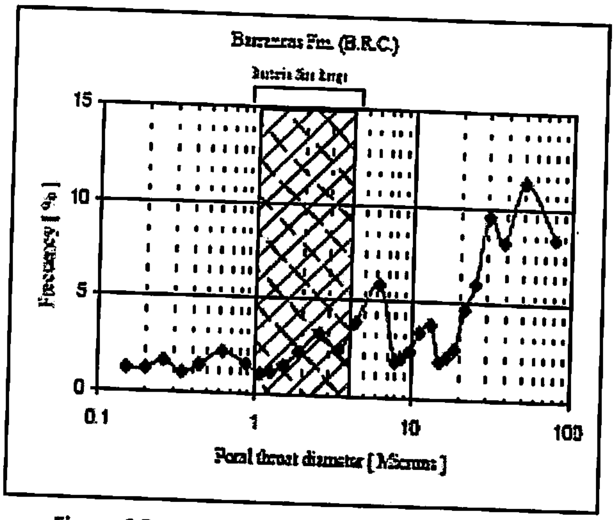


Figure 6 Pore Throat diameter of Barrancas Fm

<u>Petrophysical parameters</u>

Effective interval	:	8m
Kro(Swi)	:	0.46
Krw(Sor)	:	0.13
Swirr (%)	:	31.4
Sor (%)	:	23.3
Porosity (%)	:	16.8
Absolute Permeability (md)	:	120
Depth	:	1930
Reservoir Temperature (°F)	:	170
Original Reservoir Pressure (psi)	:	2285

Present Reservoir Pressure (psi)	:	569
Bubble Pressure (psi)	:	1023
GOR (M3/M3)	:	37
Bo factor (M3/M3)	:	1.176
Viscosity (cp)	:	4.5
API° (Bottom Hole Conditions)	:	32

Lithology: Conglomeradic and sandstone with variable interleaved shales and limonite components.

I. Rio Blanco member (V.O.)

Poral geometry:
The poral system is basically controlled by the quantity and type of cement. Capillary pressures and electronic microscopy runs on the core specimens are used to determine pore geometry characteristics. Further evaluation has detected the presence of microscopic fractures. These small fractures, which are common in this field framework contribute to the movement of fluids and permit microbes migration outward in the reservoir.

Petrophysical parameters

Effective interval	:	2-4 m
Kro(Swi)	:	0.56
Krw(Sor)	:	0.36
Swirr (%)	:	30.6
Sor (%)	:	28.2
Porosity (%)	:	16.1
Absolute Permeability (md)	:	5-10
Depth (M.b.s.)	:	2030
Reservoir Temperature (°F)	:	180
Original Reservoir Pressure (psi)	:	3371
Present Reservoir Pressure (psi)	:	1279
Bubble Pressure (psi)	:	1026
GOR (M3/M3)	:	35
Bo factor (M3/M3)	:	1.154
Viscosity (cp)	:	4.5
API°	:	32

Lithology: Good reservoirs are mainly related to the presence of sand associated with alluvial fan influx from the western flank of the basin. Deposition occurred under a persistent rain of ash, generating tuff and mixed rocks.

3.1.9 Pilot Test Design

A multi disciplinary approach towards design of a pilot test is an essential requirement.

The main objectives behind pilot design are

1. To achieve technical closure and good levels of correlation between controllable and uncontrollable groups of variables. The <u>controllable variables</u> are mainly MEOR treatment parameters. The <u>uncontrollable variables</u> are related with fluid and rock characteristics. These exert significant influence on MEOR response to a treatment.

2. Additional goals are to confirm feasibility indexes exhibited during laboratory testing. The pilot is designed to assess microbial impact on productivity index (PI) for every treated well, completion method and reservoir in exploitation.

3. A reasonable prediction capability between previous screening and post-MEOR results is another important objective.

4. Discrimination in pre- and post-pilot data information and good <u>"signal to noise ratio"</u> are very essential for a successful pilot design project. The trial needs to be programmed to see all relevant processes in time (pilot duration) and spatial dependence (number of wells, depth and structural position).

5. Minimal time scale needs to be a twelve months period.

6. Another important concept behind of pilot implementation is to reduce the uncertainty for all relevant measurement occurring during the pre and post-MEOR stages.

7. Finally, cost of pilot evaluation need to be consistent with expected benefits under different scenarios, risks and expansion strategies.

<u>Well Selection</u>

Total No. Of Wells : 29 (12 from Barancas and 17 from Rio Blanco)

Candidates selected : 6

The scheme according to which the pilot is planned to implement is:

· Barrancas Formation: A (Vertical), B (Vertical)
· Rio Blanco Formation: C (horizontal), D (horizontal), E (Vertical), F (Vertical)

Main reasons behind this selection are as follows:

i. Adequate number of candidates is required to have sufficient statistical significance and good discrimination in well by well performance evaluation during the study.

ii. Capable of discriminating microbial stimulation and EOR improvements in corresponding with control variables for each targeted reservoir (Barrancas Fm. and rio blanco Fm).

iii. All the wells are non marginal. These non-marginal wells having consistent and clear fluid production histories when compared to those producing marginal oil.

iv. All the wells producing oils are with positive bio-treatability tests.

v. Relevance to determining design consideration for future expansions.

vi. Adequate completion and extraction configuration.

OPERATIVE ASPECTS

Initial microbial treatments were variable amount of microbe laden water (having neutral PH and with solid particulate control), followed by a 72 hour shut-in period. Subsequent periodic treatments have been one third of initial volume every 15 days. Treatment design centres on seven items:

1. Method of inoculation which is based on well completion and extraction method.

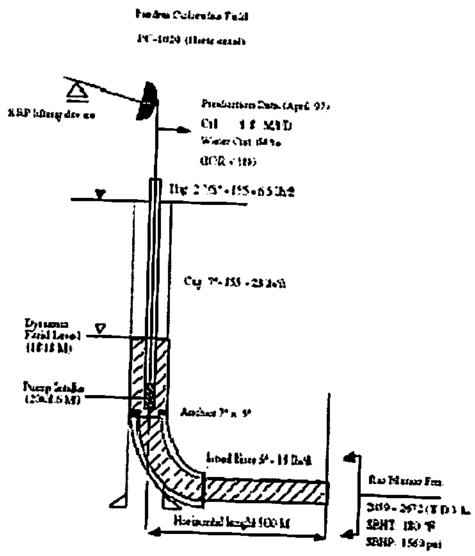


Figure 7 Horizontal Well Inoculation

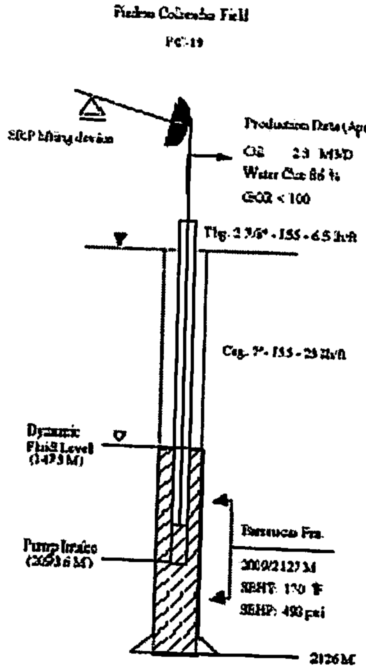


Figure 8 Vertical Well Inoculation

2. Microbial community structure.
3. Microbial product structure (product participation).
4. Blending and displacement water.
5. The total biotic concentration to use during initial and periodic treatments.
6. Frequency of periodic inoculations.
7. Initial and periodic latencies (shut-in time) that follow every treatment.

Horizontal wells

Initial inoculation conducted by squeezing method.

Initial treatment size of 150 barrels was the minimum considered, based on a lateral diameter of 0.15 m. This size would provide a bio-reactor that the production would be in for one day as it traveled to the wellbore, if the entire 150 barrels were displaced into the formation. To ensure this the treatment size was increased by the capacity of the lateral from 150 to 220 barrels. If the formation would accept a larger treatment at low pressure, an initial treatment volume two to three times this might be considered. higher microbe concentration in the maintenance tretments is advisable due the treatment size mandated by the length of the lateral. The formation needs to be over balanced in so that it can take fluid over the 3 day shut-in time. Periodic treatments were by batching using annulus space. The volume of microbeladen water was calculated so that as the fluid level in the well gradually decreases, the fluid forced into the formation is microbe-laden and not displacement water. Using pressure build up data, the bottom hole pressure at the end of three days ws used to determine approximately what the fluid level in the well would be at the end of the shutin period, and the treatment was sized accordingly.

Vertical wells

The initial treatment was designed to use a lower concntration than the maintenance treatment. Usually a 1: 211 dilution was used on the initial treatment (0.2 gal./bbl.)
and a 1:84 dilution on the maintenance treatments (0.5 gal./bbl.). The rationale is that with the longer shut-in times the microbes have more time to grow in the formation and and become established than with the shorter times normally used on maintenance treatments. For wells having a low average permeability limiting fluid input, higher concentration for the initial treatment is probably a better advice.

The maintenance (periodic) treatment size of 50 barrels was selected as a compromise between radius of microbial penetration and quick fractional flow stabilization after shut-in period. validated this assumption. Both initial and periodic treatments were by annulus.

The original program of treatments is summarized in Table

1. The participation of the product was as follows:
   P #1: 28.5%
   P #4: 13.5%
   P #5 : 9.5%
   P #6 : 48.5%.

Microbial sub-communities are presented in liquid medium as concentrates, having 106 – 108 viable microrganism per ml. Microbial liquid product (five gallon drums) was stored out of direct sunlight and extreme weather conditions (+5 to +30 °C), thus avoiding freezing temperatures to affect them.

Table 3 Original Treatment Design of the Job

Treatment Design (original)

Well	Start Date [dd/mm/aa]	C.I. [Gal]	L.I. [hs]	C.P. [gal]	L.P. [hs]	Frequency [T/month]	Method
PC-1020 H (V.O.)	17/3/97	63	72	9	24	2	*Squeeze/Batch
PC-1020 H (V.O.)	03/04/97	63	72	15	24	2	*Squeeze/Batch
PC-68 (B.R.C.)	31/03/97	63	72	8	24	2	Batch
PC-19 (B.R.C.)	27/03/97	63	72	8	24	2	Batch
PC-94 (V.O.)	24/03/97	63	72	8	24	2	Batch
PC-86 (V.O.)	20/03/97	63	72	7	24	2	Batch

C.I.: Initial Concentration of Microbial Concentrates (P#1,P#4, P#5 and P#6)
L.I.: Latency (initial shut-in time)
C.P.:Periodic Concentration
L.P.:Latency (Periodic shut-in time)
Frequency: Treatments per month
* Inoculation method, Squeeze only for Initial Treatment

Technical aspects

Methodology to evaluate MEOR performance

MEOR's long-term distinctive <u>response is to increase net oil rate</u> and simultaneously to reduce Water Cut. This typical duality in MEOR response is explained by the change in apparent oil and water mobilities in the colonized portion of the reservoir, known as the **bioreactor.**

Project Performance is evaluated well by well by tracking Productivity Index (P.I.) evolution.

$$MEOR_{(T_i)} = \frac{\dfrac{Qmeor_{(t_i)}}{Pe - Pwfmeor_{(t_i)}}}{\dfrac{Qo_{(t_i)}}{Pe - Pwf_{(t_i)}}}$$

Individual well testing into common battery of wells and last generation echometry were used to have good and sufficient data input for calculating and updating P.I. Four production tests per well per month, with confirmatory duplicate tests, were the usual monitoring techniques used to track project performance. Special care was taken to verify that there was a sufficient constancy in dynamic fluid levels pre- and post-MEOR.

Pre-MEOR adequate baselines for every well were calculated before starting the program of inoculations. *Low noise (data scatter)* allowing consistent decline curve determination is of the utmost importnce for proper discrmination of microbial effects on well and reservoir productivity.

3.1.10 Project Evaluation:

Project evaluation is based on a customized set of MEOR Performance Curves (MPC). The use of MEOR performance curve methodology is accomplished in four basic steps:

i. First, lab screening procedures are conducted to test rheology behaviour in produced oils using control and inoculated samples for every well

ii. Second, Incremental Oil Rates (IOR) and Water Cut vs. time figures are forecast according to the treatment designs, reservoir and well completion information;

iii. Third, predicted curves are correlated with field performance data during pilot implementation; providing insights and guidelines for process optimization and treatment design alteration and modifications, permitting assessment of MEOR prospects and offering practical guidelines during field implementation and pilot project follow-up monitoring; and

iv. Fourth, economical models are run to calculate updated profitability indexes.

Field data was matched using radial/elliptical flow model expressions considering concentric coupled zones of altered and original fluids. The model considers the oil as non - Newtonian, shear-rate-dependent fluid. Mechanistic models could be easily adjusted to take into consideration horizontal completion geometry and permeability anisotropy.

Net Oil Increment:
The evaluation of incremental oil was undertaken **using simulations** which consider two parameter rheological models. Results are dimensionless time-dependent values of Productivity Indexes for the oil fraction before and after MEOR.

The influence on MEOR response of petrophysic parameters is mainly associated with two aspects:

1. Microbial Migration Rate (MMR) is related to reservoir poral geometry (pore throats distributions); and

2. Shear Rate Field (SRF) is based on colonized reservoir and fluid flow dynamics and their connection with apparent viscosity.

MMR correlate very well with how quickly the maximum MEOR response is obtained (improvement in, PI). This point will be dependent on final radius of bacteria penetration and density of colonies in the corresponding reservoir poral spectra. SRF has a singular importance with shear rate sensitive oils (pseudoplastic behavior) and defining the degree of compositional alteration.

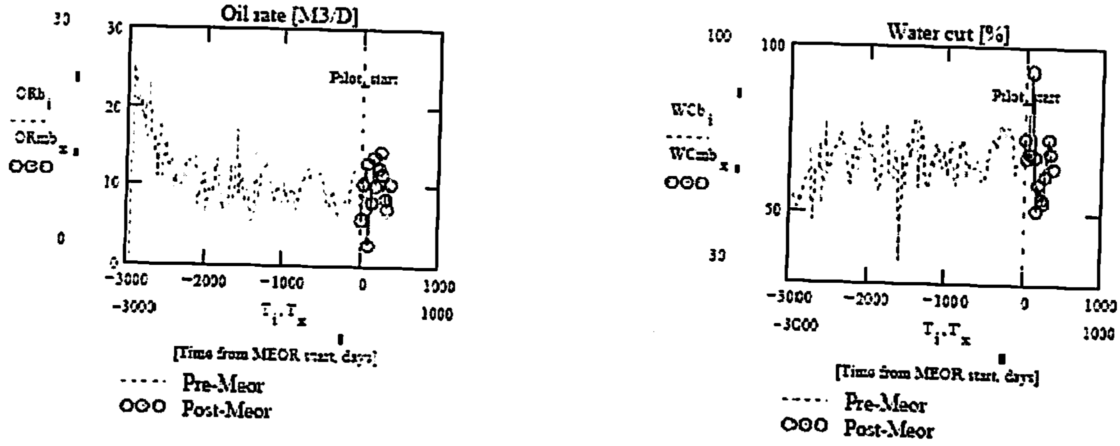


Figure 9 Performance Curves from Simulation Software

Composite performance is showing in next graph. Change in oil decline tendency before and after MEOR is clear and well defined in the curve. Incremental Oil averages 66% over baseline (dashed) with minimal values of 28.5% and maximum above 110%, in close correlation with oil °API variation:

PC-19	Pre: 19.3 , Post: 24.0 °API;
PC-1020	Pre:21.9, Post: 23.3 °API

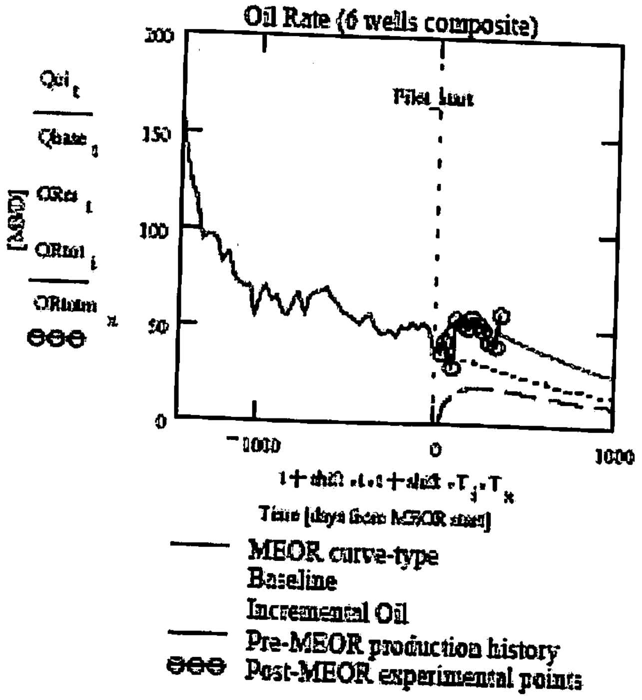


Figure 10 Composite Performance Curve

Water Cut Reduction

Water cut tendencies for the six well composite is shown in the curves. Water influx is decreasing in relation with oil rate. Change in water cut tendency is evident and is a clear indication of compositional and mobility alteration at reservoir conditions.

Experimental Design

To analyze MEOR performance correlation with specific variations in treatment parameters, a limited Experimental Design was conducted beginning mid-course in the original inoculation schedule. Mann-Whitney (Non parametric test, also named U proof) statistic procedure was used to verify degree of significance between treatment changes and MEOR response.

ED results:

Segment Baseline –

A: Clean up;

BC: Microbial colonization;

CD: Colony retraction (well is understimulated);

DE: re-colonization after of concentration Changes

Table 4 The Experimental Design Treatment Modifications

Treatment modifications (Experimental Design)

Well	Original concentration		Modified concentration		Percentage of change
	Time interval	[gals]	Time interval	[gals]	
PC-1020 H (V.O.)	17/3 - 15/5	9	15/5 - 15/6	20	+122 %
PC-1020 H (V.O.)	3/4 - 15/5	15	15/5 - 15/6	25	+66 %
PC-68 (C.R.I.)	31/3 - 15/5	8	15/5 - 15/6	16	+100 %
PC-19 (C.R.I.)	27/3 - 15/5	8	15/5 - 15/6	8	0 %
PC-94 (V.O.)	24/3 - 15/5	8	15/5 - 15/6	8	0 %
PC-86 (V.O.)	20/3 - 15/5	7	15/5 - 15/6	14	+ 100 %

Table 5 Comparison of the Post MEOR and Pre MEOR job oil rates

Oil rate comparison

Well	ORo [M³/D] Pre-MEOR	ORm1 [M³/D] Post-MEOR Phase 1	ORm2 [M³/D] Post-MEOR Phase 2	ORm3 [M³/D] Post-MEOR Post. Modif.
PC-1020 H (V.O.)	8.8	18.3	13.0	17.0
PC-1020 H (V.O.)	19.9	33.9	14.6	20.7
PC-68 (C.R.I.)	3.9	4.4	5.9	6.1
PC-19 (C.R.I.)	2.3	4.4	8.3	Unmodified
PC-94 (V.O.)	13.6	23.9	15.5	Unmodified
PC-86 (V.O.)	8.0	8.2	6.7	11.7

Table 6 Water Cut Comparison of the Pre MEOR and Post MEOR phases

Water Cut comparison

Well	Wc [%] Pre-MEOR	Wcm1 [%] Post-MEOR Phase 1	Wcm2 [%] Post-MEOR Phase 2	Wcm3 [%] Post-MEOR Post. Modif.
PC-1020 H (V.O.)	64.0	39.0	45.8	39.1
PC-1020 H (V.O.)	72.5	44.0	70.7	59.5
PC-68 (C.R.I.)	68.6	67.5	65.0	55.6
PC-19 (C.R.I.)	86.6	72.3	72.8	Not modified
PC-94 (V.O.)	62.3	51.6	58.7	Not modified
PC-86 (V.O.)	56.6	54.5	63.3	40.0

Rheological comparison

A clear and remarkable improvement in oil rheology was Detected

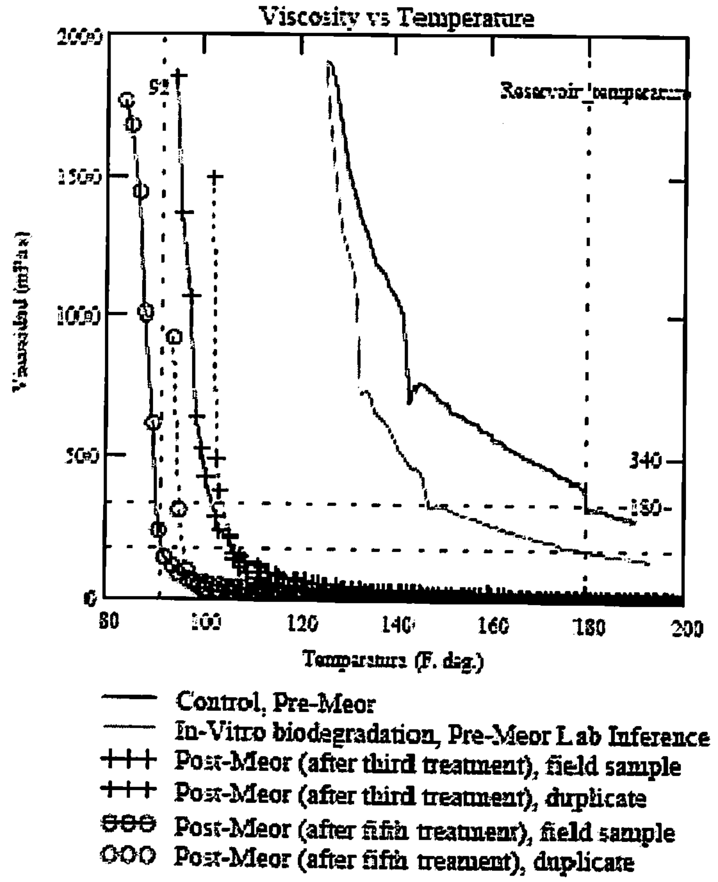


Figure 11 Variation of Viscosity with Temperature

Geochemical comparison significant alteration in oil geochemical properties, biomarkers and fingerprints was also detected. Light ends (S1) are mainly originated by enzymatic cracking onn n-alkanes (S2), and their increase continues over the life of the project. On the other hand the increase in heavy compounds (S3, S5) occur during initial reactivity.

API gravity show a consistent and increasing trend:

°API variation (lab normalized conditions)
A
Pre-MEOR: 19.3
Post-MEOR: 24.0 D: +4.7

B
Pre-MEOR: 21.9
Post-MEOR: 23.3 D: +1.4

Saturates hydrocarbons

A

Pre-MEOR: 62.2 Post-MEOR: 66.9

B

Pre-MEOR: 57.1 Post-MEOR: 68.4

Light end alteration: C6 and C7 components

A (C6 C7)

Pre-MEOR: 0.30% 0.57%

Post-MEOR: 1.34% 2.08%

B (C6 C7)

Pre-MEOR: 0.68% 1.00%

Post-MEOR: 0.82% 1.33%

Conclusions

1. MEOR is technically feasible in Piedras Coloradas field.
2. Both formations test positive with similar performance figures.
3. MEOR on horizontal completions has interesting and positive effects in terms of restoring productive length and size of colonized areas.
4. A high correlation exists between the Piedras Coloradas and other projects in both conditions and performance.
5. Multidisciplinary team integration and proper monitoring techniques are the key factors to optimise the fractional flow that is obtained and incremental recovery in microbial stimulated reservoirs.
6. MEOR is profitable at pilot and scaled stages.

3.2 CASE II

A Study of a MEOR Job Performed by Oil India Limited in Barail 3rd & 4th Sand Upper Tipam Horizon

After the boom gained by MEOR throughout the world, ONGC & TERI developed bacterial strains effective upto 90 ° C from formation water samples. Based on encouraging results in ONGC's wells, OIL decided to implement MEOR in its fields in suitable wells having BHT of 70-85 ° C in two phases of 3 and 5 wells in 2005 and 2008 respectively.

Several field tests were conducted to screen the wells to be selected for the job. The criteria defined for the selection was decided by OIL based on the test results obtained. The bottom hole temperature (BHT) for the target formation is desired to be 75-80° C. The preferred water cut is 70%-80% while the injectivity of a minimum 250-300 lpm (minimum). The injectivity is to be conducted at 75kg/cm^2. The °API of target oil should be greater than 15 to facilitate the easy integration of the culture and the lighter end disintegration. Also, mobility enhancement of lighter crude would enable the production to occur at a higher rate. A residual saturation range of 20-25% is preferred for the job.

The above Selection Criteria is summarised as follows:

BHT : 70-85° C

Water Cut : 70-80% preferred

Injectivity : 250-300 lpm (minimum) at 75kg/cm^2

°API of oil: >15

Residual Oil Saturation : 20-25°C

3.2.1 Well Data:

Table 7 Well Data of Barail 3rd and 4th Sand zone Tipam horizon

Horizon	Barail 3rd Sand, Barail 4th Sand, Upper Tipam
Formation	Sand stone

Geological age	Oligocene/ Upper Eocene/ Miocene
Perforation, m	4-20
Net Pay, m	13-29
Permeability, md	40-400
Mode of Production	Gas Lift
Initial Reservoir Pressure, kg/cm2	238.5-303.3
Reservoir Pressure, kg/cm2 at the time of job	70-230
BHT ° C	72-85

3.2.2 Inoculation Studies

Inoculation was carried out by using 200 litre of bacterial seed. These were inoculated and incubated at BHTs of the wells for 3 weeks. Several parameters of the culture were monitored during the incubation process, such as:

1. pH of the bacterial solution

2. IFTs of crude oil in bacterial solution

3. Microscopic examination of growth of S-2 culture in bulk culture

4. Total Colony Forming Units (CFU) in bulk culture

5. Monitoring of Volatile Fatty Acids (VFA) in bulk culture

3.2.3 The Job Design

Activities prior to the MEOR job:

Before the microbial culture is employed to affect the target zone, well testing activities for around 24 hrs is carried out. The results of the tests provided the liquid rate (Q_l) in klpd, water cut in % and the oil rate (Q_o) in klpd. Also the collection of oil and water samples for the estimation of viscosity, pour point, API, ionic composition, salinity etc is undertaken. The data obtained is indicative of the viability of the zones under consideration. The data for injectivity test in litres/min at 75 kg/cm^2 is also acquired.

3.2.4 Execution of the Job

Preflush
Injection of 30 kl of nutrient medium at a rate not exceeding 1.0-1.5 bbl/min at 75 kg/cm2.

The Main MEOR Slug
Nutrient medium injection (140 kilolitre) containing bacterial consortium at the rate 1.5-2.0 bbl/min at surface pressure not exceeding 75 kg/cm2.

Overflush: Injection of nutrient medium (30 kilolitre) at the rate 2.0 bbl/min at pressure not exceeding 75 kg/cm2 followed by one tubing volume of chase water.

Well Closure: The Well is closed for 3-4 weeks

Total Biological Solution injected –200 kilolitre

3.2.5 The Pre and Post Job Observations:

Pre job Lab Observations:

1. The pH of the bacterial solution is reduced by 1-1.2 units indicating production of acidic components in the bio reactor.

2. Inter facial Tensions of crude oil in bacterial solution are reduced indicating production of bio-surfactant.

3. VFA concentration was significant in the bulk culture studied on 10th day

4. The CFU observed was 16500000 per ml on 10th day of incubation of the bulk culture.

Post job lab observations:

1. All the post job well head samples showed decrease amount of VFA's.

2. CFU count in the produced water from all three wells dropped significantly with time & after 6 months the count became insignificant

3. Initial phase produced water had lower pH in well-II-Indicates generation of acids during the metabolization of bacteria in the formation.

4. The chemical characteristics of produced oil did not show significant change in properties

3.2.6 Pre Job Production Data

Table 8 The Pre Job Production Data of the 8 wells

Parameter	Well I	Well II	Well III	Well IV
Oil Rate, klpd	2.5	8.5	2.9	14.8
Water Rate, klpd	25	836	67	43.9
Water Cut %	91	81	96	74.7
Injectivity, lpm at zero surface pressure	>300	>300	>300	>300

Table 9 The Pre Job Production Data of the 8 wells - II

Parameter	Well V	Well VI	Well VII	Well VIII
Oil Rate, klpd	6.6	4.4	4.4	2.1
Water Rate, klpd	25.3	12.5	24.6	17.7
Water Cut %	78.6	66.6	81.1	89.3
Injectivity, lpm at zero surface pressure	>300	>300	>300	>300

3.2.7 Production Behaviour & Data Plots: Pre and Post Job

Table 10 Comparison of Post and Pre Job Production Data

Well No.	Pre job prodn data			Post job prodn data			Remarks
	Avg Oil, klpd	Avg Water, klpd	Avg Oil (%)	Avg Oil, klpd	Avg Water, klpd	Avg Oil (%)	
I	2.5	25	9.1	3.1	26.7	10.4	Post Job data average of 8th month till Dec'05. Peak oil rate 4.1 klpd in 3rd and 5th

							month after job.
II	8.5	36	19.1	10.4	31.7	24.7	Post job data avg of 7th month till Dec'05. Peak oil rate 12.6 klpd in 4th month after job.
III	2.9	67	4.1	1.0	62	1.6	Post job data avg of 6th month till Dec'05. Peak oil rate 2 klpd in 4th month after job.
IV	14.8	43.9	58.7	25.3	16.4	71.9	Pre job data avg of 4th month till Dec'07. Post job data avg of 12 months Dec '08 Peak post job rate 23.5 klpd immediately 1 month after job.

Well No.	Pre job prodn data			Post job prodn data			Remarks
	Avg Oil, klpd	Avg Water, klpd	Avg Oil (%)	Avg Oil, klpd	Avg Water, klpd	Avg Oil (%)	
V	6.6	25.2	31.8	21.5	5.5	26.9	Pre Job data average of 8th month till Nov'07. Post Job data avg of 13 months till Dec' 08. Peak post job rate 7.8 klpd 7.8 klpd 6-7 months after the job.
VI	4.4	12.5	16.8	33.1	1.7	16.2	Pre Job data avg of 8 month till Dec '07. Post job data avg of 11th month till Dec'08. Peak oil rate 2.86 klpd in Oct '08.
VII	4.4	24.6	28.9	18.9	6.3	26.7	Pre job data avg of8 months till Dec'07. Post job data avg of 12th month till Dec'08. Peak

							oil rate 8.6 klpd Aug '08 to Dec '08, 8-12month after job..
VIII	2.1	17.7	19.8	10.7	7.9	20.9	Pre job data avg of 8th month till Jan'08. Post job data avg of 11 months Dec '08 Peak post job rate 10.5 klpd May June '08, 4-6 month after the job.

Calculation of the Net Oil Gain

Table 11

Well No.	Oil Gain, kl	Oil Loss, kl	Remarks
I	100		Wells were monitored for 6-8 months
II	500		
III		485	
IV			
V	333		Wells monitored for 10-13 months Marginal oil gain is of ~ 153 kl in well IV
VI		1064	
VII	1167		
VIII	1771		
Net Oil gain	3871	1549	
Net Oil gain	**2207 kl**		

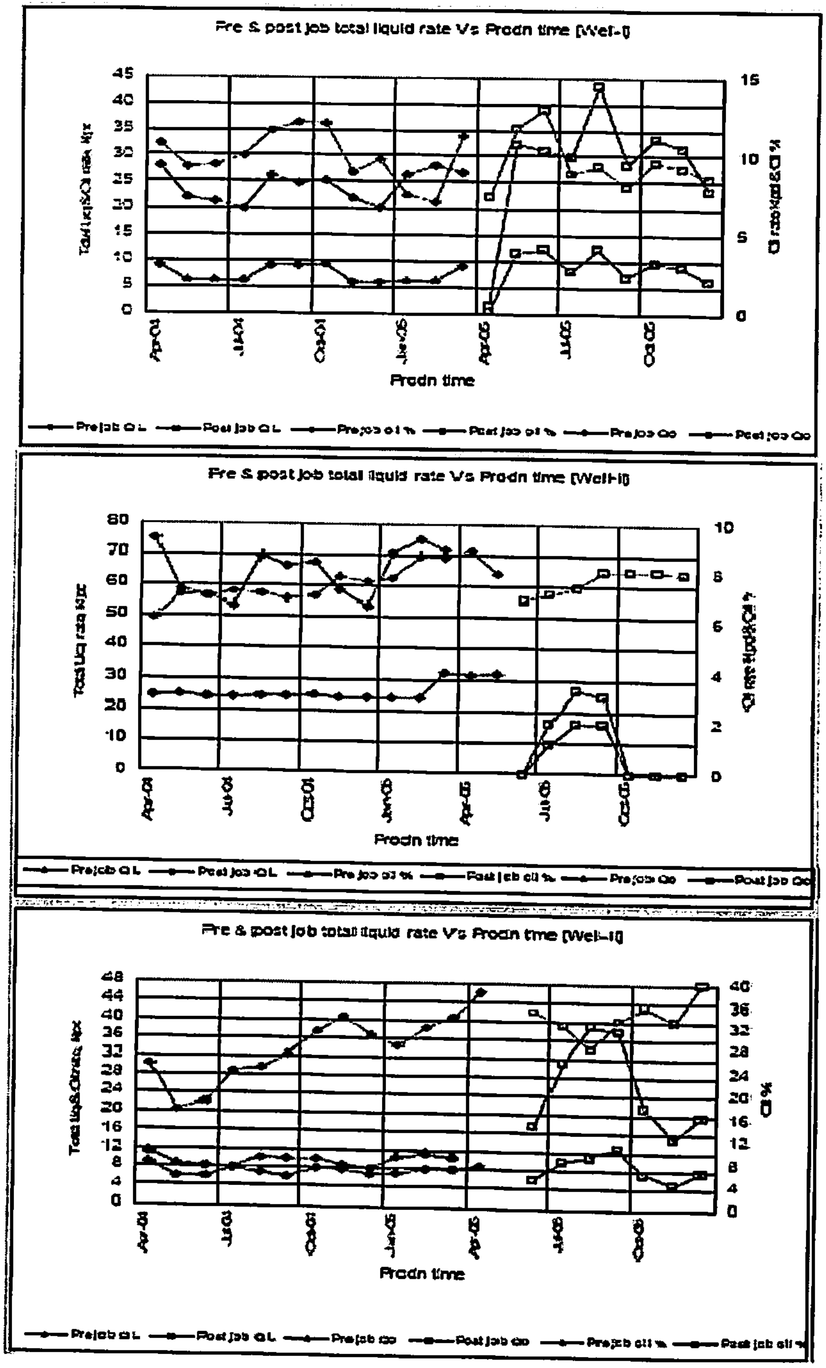


Figure 12 Results of the Calculations Plotted on the graph (Time vs Total Liq Rate)

Similar plots were obtained for all the wells.

3.2.8 Cost Analysis

i. Average cost incurred per well was Rs 14.2 lakh

ii. Average cost of consumables per well was Rs 3.6 lakh (for a job volume of 200 kl.)

iii. AddiStional oil required to be produced to cover the total cost of USD 254,000 was 610 kl (considered avg crude oil price @ USD 66/bbl)

iv. Additional oil produced in 6-8 & 10-13 month post job period in 2005 and 2008 was 2200 kl (approx)

3.2.9 Case Inference: Observations and Results

The MEOR job was carried out on 8 wells, of the Barail 3rd and 4th sand of Upper Tima horizon. These wells were pre treated and tested significantly to characterise the reservoir and consolidate all the field parameters.

The screening criteria of the well were established based on the tests performed on the field of study. A minimum criterion has to be met by reservoir to engage it with a bacterial application, with a view to improve the recovery. This criteria was employed for well selection to carry out the job.

Inoculation was carried out with 200 litre of the consortium for 3 weeks, followed by the main job design and its execution. A careful assessment of the parameters to be controlled and monitored was made to avoid inefficiency of the job. Preflush with 30 kl of the medium under predetermined conditions was done as the first step of execution followed by the main MEOR slug and the last stage of overflush.

Observations and results of the MEOR application to the reservoir were tabulated to assess the effect of the job on recovery fractions. The results were observed initially at the lab stage. Pre job lab observations, when compared to the post job lab observations, showed a significant enhancement of parameters such as the water cut and pH alteration. This is indicative of the effectiveness of the bacteria in altering the production conditions.

With the help of pre job production data and post job production data, data plots and the production behaviour was studied and the results showed the increased percentage(%) of the oil average recovered from various wells.

Plots for the recovery improvements were also constructed and studied. It could be seen that

1. Out of the 8 MEOR jobs carried out, oil gain has been achieved from 5MEOR jobs, which gives the effectiveness (e) of the project as,

$e = (5/8) * 100$

$= \underline{62.50\ \%}$

2. Oil gain in 3 wells is seen to be significant and in 2 wells it can be considered to be marginal due to very low improvements.

3. Marginal oil gain in 1 well is considered due to optimization of production operations rather than MEOR job.

4. Loss of oil was observed in Well III and Well VI, which led to the reduction of the net volume of oil gained.

5. From the plots and the post job production behaviour analysis, the effectiveness of the treatment appears to last for about 6-7 months.

6. Considering the cost analysis of the whole project provided, MEOR is not very expensive and appears to be economic.

3.2.9 Suggestions

Based on these two phases of MEOR job in 8 wells, it can be concluded that the MEOR technology appears to be beneficial in enhancing the oil production to a limited extent. Extensive R & D work should be carried out in-house as well as with reputed bio-tech laboratories to develop bacterial consortium which could be more effective than the present one in OIL's wells. Also there is a serious need to look for appropriate and suitable substitute for presently used molasses as nutrient which is very difficult to procure

3.3 Case III

A Numerical Study of Steam Assisted Gravity Drainage (SAGD) in a Single Well SAGD (SW-SAGD) process.

3.3.1 Problem Definition

To understand the early time performance response of a SAGD project, in relation to the heating efficiency of the near wellbore area. Also, a sensitivity analysis is carried out to ascertain the well completion configuration, reservoir properties and fluid conditions under which SAGD would prove to be a beneficial method of production.

A numerical simulation study was performed to quantify combinations of cyclic steam injection and steam circulation prior to SAGD in an effort to better understand and improve early-time performance. The results from this study, include cumulative recoveries, temperature distributions, and production rates. It is observed that CSS of the reservoir offers the most favorable option for heating the near-wellbore area. This creates conditions that improve initial SAGD response. An increased response was observed under more favorable reservoir conditions such as low viscosity, thick oil zones, and solution gas, improved reservoir response. Under unfavorable conditions, response was stunted.

3.3.2 Basic Idea:_ To assess the performance response of the initial phase, it is essential to heat the near well bore area rapidly and efficiently to achieve a significant response.

3.3.3 Model Description

Reservoir and fluid properties represent a typical Alberta reservoir.

a) To gain an understanding of early-time performance, various <u>computer simulations</u> were built and compared. The processes examined include cyclic steaming (CSS), steam circulation within the well, an extreme pressure differential between the injection and production sections of the well, among other parameters. Each initial operating period was followed by SAGD.

b) For the sensitivity analysis, a base case against runs was compared in which oil viscosity and gas content, reservoir height, permeability anisotropy, and finally the well completion were varied. Computer Modeling Group's (CMG) STARS thermal simulator was used to perform all of the work.

3.3.4 The Given Data

1. The well spacing is 160m.
2. A multiple pattern of well development is used.
3. A single horizontal well
4. Well is represented using a discretized wellbore model that accurately represents fluid and heat transfer in the well
5. Table 1 lists the exact dimensions of the reservoir model, grid-block information, and reservoir properties.

Table 12 Given Reservoir Data for the SW-SAGD Numerical Simulation Analysis

Grid System		**Rock Properties**	
Total No. Of Blocks	5,568	Porosity	33%
X	1400 m	Kh	3400 md
Y	80 m	Kv	800 md
Z	19.6 m		
Length	800 m		
Reservoir Properties		**Oil Properties**	
Initial Press	2654 kpa	Components	Water oil gas
Initial temp	16^{o} C	Initial Composition	90% (mole) oil 10% (mole) gas
So	85%		
Sw	15%	Viscosity vs Temp Fuction	$\upsilon = 1.74x10_{\square 6}exp \frac{6232.74}{T}$

7. Hence, the ratio k_h:k_v is about 5 to 1.

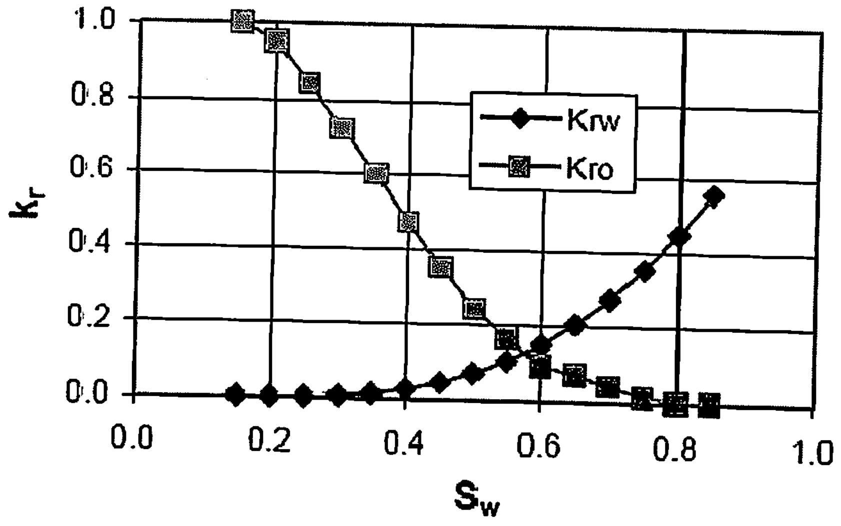


Figure 13 Sw vs Kr Plot

8. Gas-oil ratio (GOR) = 28 SCF/STB.
9. Oil viscosity at the initial reservoir temperature is 4043 cP
10. An increase of oil temperature to 100 °C decreases the oil viscosity to 30 cP.

Property	Operating Condition			
	SAGD	Extreme	Cyclic	Circulating
steam temperature (°C)	295	295	295	295
max. injection rate (CWE m^3/day)	200	600	300	300
max. injection pressure (kPa)	10,000	10,000	10,000	10,000
max. production rate (m^3/day)	300	600	300	300
min. production pressure (kPa)	500	500	500	500

Figure 14 The Operating Constraints for the varying operating conditions in SW-SAGD job

11. For a maximum injection pressure of 10,000 kPa, as reported in Table 2, the reservoir depth would have to be greater than roughly 450 m to avoid fracturing, assuming that overburden pressure increases at 22.6 kPa/m

12. Duration of attempts – 100 days to heat the near well region

3.3.5 INITIAL STAGE PERFORMANCE STUDY

The operating conditions displayed in Table into 7 cases:

(i) SAGD operation conditions from the start
(ii) Extreme pressure differential between injector and producer sections for 100 days followed by SAGD
(iii) Steam circulation for 100 days followed by SAGD,
(iv) Circulate for 100 days followed by 100 days of an extreme pressure differential followed by SAGD
(v) Cycle once followed by SAGD
(vi) Cycle twice followed by SAGD
(vii) Cycle three times followed by SAGD.

NOTE: In each case except the first, an initial preheating phase precedes SAGD.

3.3.6 RESULTS

Results of this screening study are displayed in Figures 4 to 6.
Following figures display recovery factor histories for the first year of production and for 10 years of production, respectively.

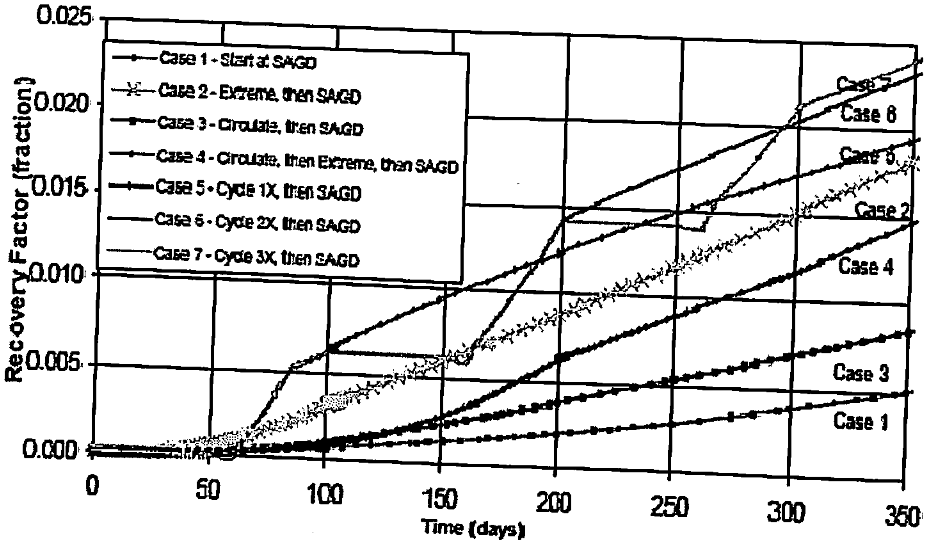


Figure 15 Results of the simulation run (Time vs Recovery Factor)

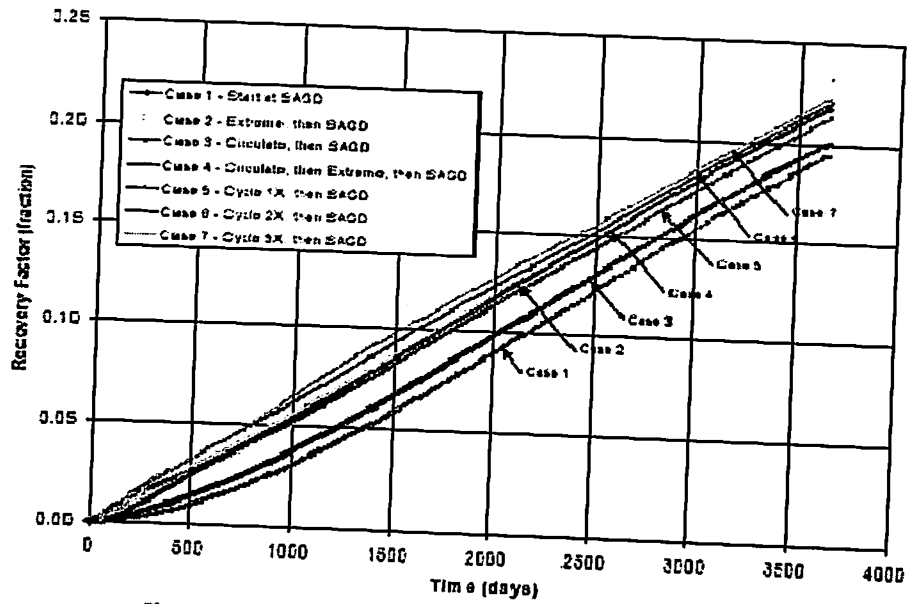


Figure 16 Result of the simulation run (Time vs Recovery Factor)

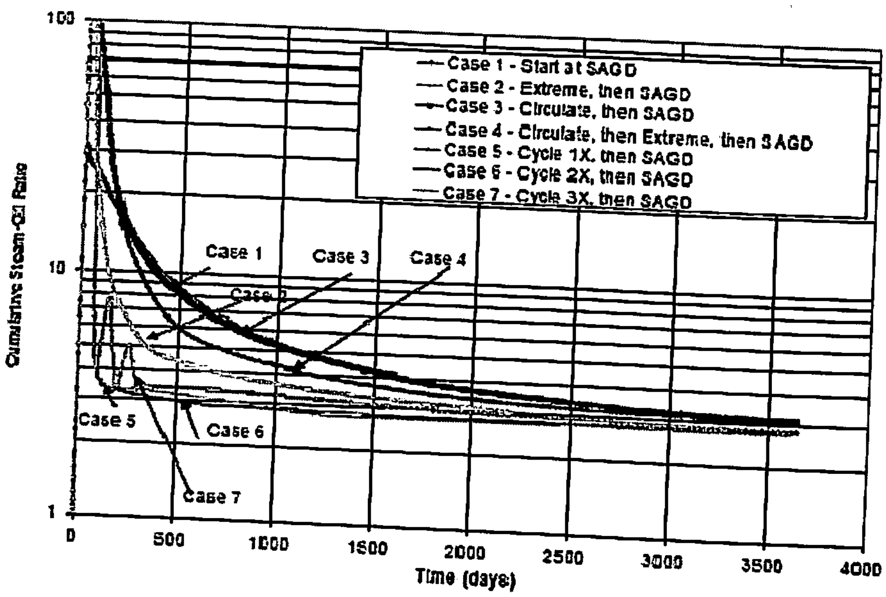


Figure 17 Result of the simulation run (Time vs CSOR)

3.3.7 OBSERVATIONS:

1. It can be seen that it is possible to improve initial production response.
2. Cyclic steaming as applied in Cases 5 to 7 leads to the most rapid oil recovery.
3. However, the late time recovery performances shown in Fig. display similar behavior for all cases. Recovery factor ranges from 19-22% after 3650 days of injection and all curves increase at similar rates.

4. The CSOR varies substantially among the studies during the initial period because significantly different production and injection schemes were used. At late time, however, the CSOR for all cases averages roughly 3.0. Note, however, that the cyclic cases perform somewhat better, with regard to CSOR, in initial and late-time response

3.3.8 Case Analysis and Observations

Three of the cases above will be examined.

Case 1 Continuous SAGD.

No Preheat phase. Direct SAGD

a. Figure 7 displays the injection and production curves for Case 1.

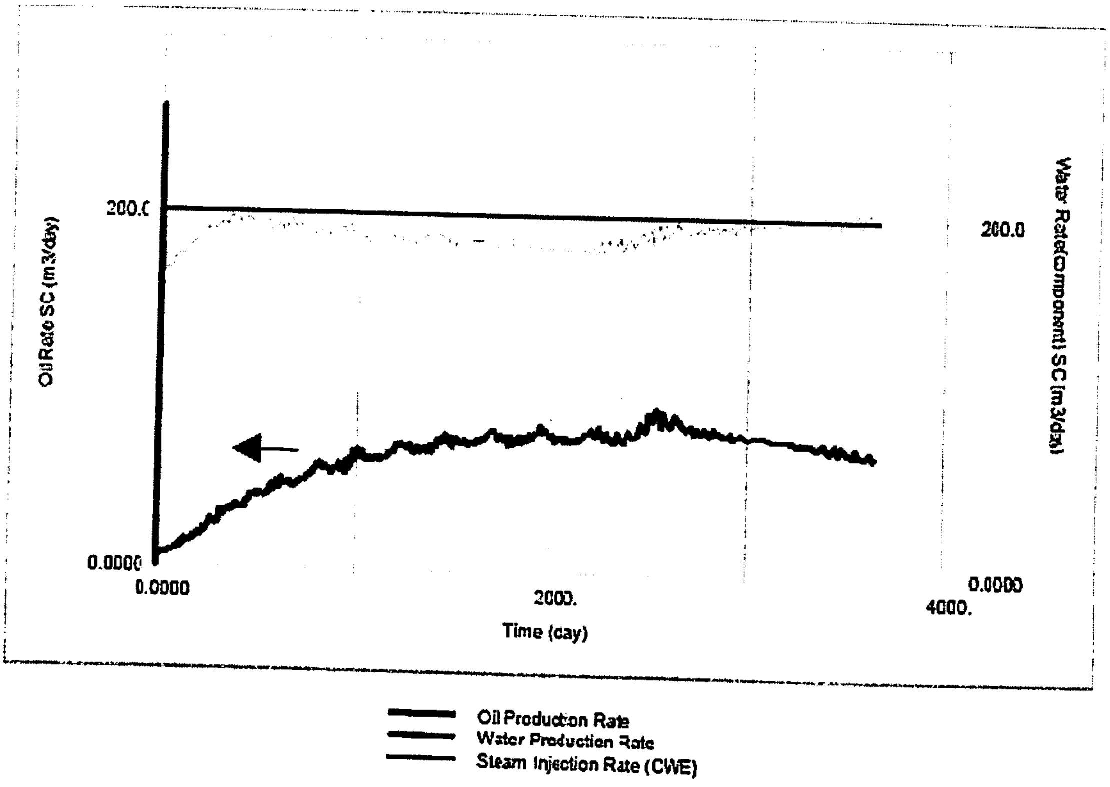


Figure 18 Result of simulator run (Oil rate vs Time) Case – 1

As expected, the initial oil rate is low, but increases with time as a steam chamber slowly develops and more oil is heated. Oil production peaks at roughly 80 m3/day.
Steam shortcircuiting can be seen from the above curve and thus the contact time between the steam and the reservoir is short.

b. Figure 8 displays BHP curves for injection and production in Case 1.

A large pressure differential of about 3000 kPa exists initially between the two sections of the well. Over time, the reservoir pressure decreases because we produce more fluids than we inject. This also causes the injection pressure to decrease.

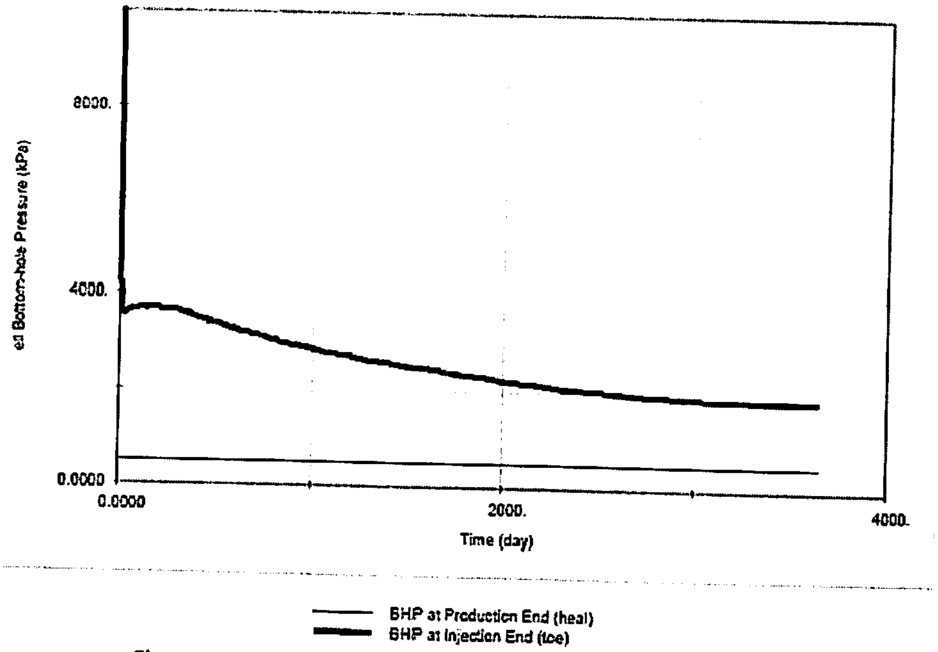


Figure 19 Result of Simulation Run (BHP vs Time) – Case 1

Later, a large steam chamber grows in the middle region of the system. At 100 days, However, the steam chamber is just beginning to grow above the area between the injection and production sections. It is important to maximize the amount of net heat injection into the reservoir at early times to maximize the size of the heated volume surrounding the wellbore.

Case 2: Extreme Pressure Differential Prior to SAGD

The pressure differential is increased by increasing the injection pressure constraint.

a. Figure 10 displays the BHP histories. For the first 100 days, the steam is forcibly injected into the formation at around 7000kpa, thus increasing the reservoir pressure.

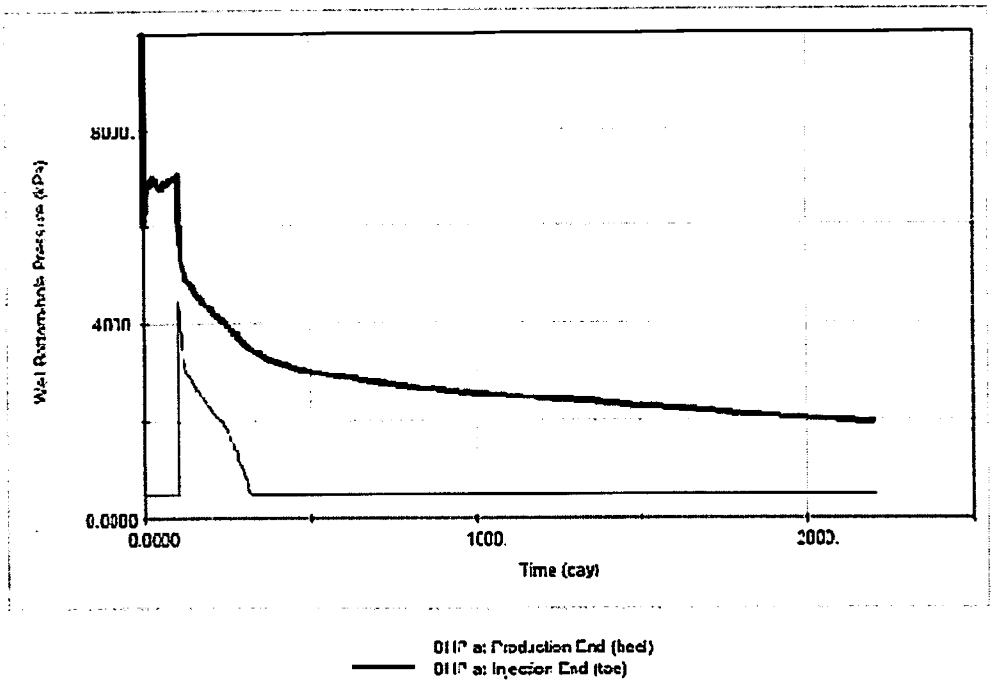


Figure 20 Result of the Simulation Run (BHP vs Time) – Case 2

b. Figure 11 displays the production response for the extreme period in the first 100 days followed by SAGD.

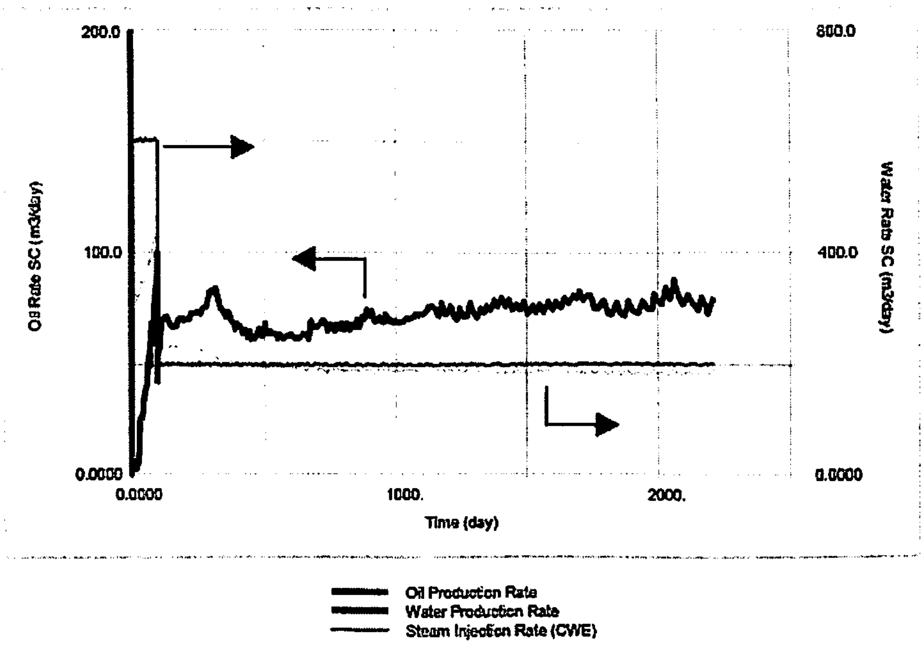


Figure 21 Result of the Simulation Run (Oil rate vs Time) – Case 2

Observing the oil rate in the first 100 days and comparing to Fig. 7, we see that the oil rate ramps up faster than Case 1.

This is logical because Case 2 is an accelerated version of SAGD.

Injection conditions have led to high reservoir pressure at the beginning of SAGD, causing significant production through pressure depletion in addition to gravity drainage of heated reservoir fluids.

The problem of improving early-time performance of SW-SAGD transforms into a problem of heating rapidly the near-wellbore area to create conditions that allow gravity drainage of oil. More specifically, for a steam chamber to grow, oil viscosity must be low enough so that fluid drains creating voidage for steam to fill.

Comparing the various simulation results, CSS is found to be the most efficient method of heating the near-wellbore area. Heating is much more rapid than relying on conduction alone.

3.3.9 SENSITIVITY ANALYSIS

The analysis is done to estimate the effect of reservoir parameters on the production performance.

THE BASE CASE

Property	Operating Condition	
	Initial Cyclic	SAGD
steam temperature (°C)	295	238
maximum injection rate (CWE m^3/day)	300	200
maximum injection pressure (kPa)	8000	3230
maximum production rate (m^3/day)	300	300
minimum production pressure (kPa)	2230	500
Oil Viscosity		
20,000 mPa-s case (μ (mPa-s), T(K))	$\mu=8.61\times10^{-6}\exp\frac{6232.74}{T}$	
40,000 mPa-s case (μ (mPa-s), T(K))	$\mu=1.72\times10^{-5}\exp\frac{6232.74}{T}$	

Figure 22 The Sensitivity Analysis: Base Case Data

The base case consists of two steam injection cycles followed by SAGD operating conditions.

Given Data

1. Maximum reservoir pressure to **8,000 kPa**
2. Injection temperature was **296 °C**
3. During SAGD original reservoir pressure of **2654 kPa**
4. **Rate constraints remained the same** at 300 m^3/d maximum liquid production and 200 m^3/d maximum steam injection rate.
5. Maximum injection pressure was set slightly above initial reservoir pressure at 3230 kPa; minimum production pressure was set slightly below initial reservoir pressure at 2230 kPa.

*Between the injection and production sections of the horizontal well, a **30 m** long unperforated section was added. This is an attempt to force steam to penetrate substantially far into the reservoir and reduce the amount of steam short-circuiting.*

Sensitivity Cases

(i) A base case with the properties in Table 1 and operating conditions shown in Table 3
(ii) Dead oil to examine the effect of solution gas

Two periods of cyclic steam injection precede continuous injection and production. During both the periods, steam is injected for 50 days at a rate of 300 m^3/day.

The maximum allowed pressure of 8000 kPa. The soak period is 10 days and the length of production is a relatively short 40 days to avoid large heat withdrawal from the reservoir. Continuous SAGD operating conditions follow. All of the various sensitivity runs follow this procedure.

Note that recovery factors are less here, compared to the early-time study, Fig. 5, because the steam injection pressure has been reduced substantially.

The base horizontal to vertical permeability ratio, k_h:k_v, is 4.25. The vertical permeability was adjusted to create three more cases with ratios of 1, 2, and 10. In all cases, the horizontal permeability remained fixed at 3400 mD. Larger ratios present less favorable conditions for upward steam migration and oil drainage.

With an increase of kh:kv, cumulative recovery at a given time decreases and the CSOR increases, as shown in Figs. 16 and 17.

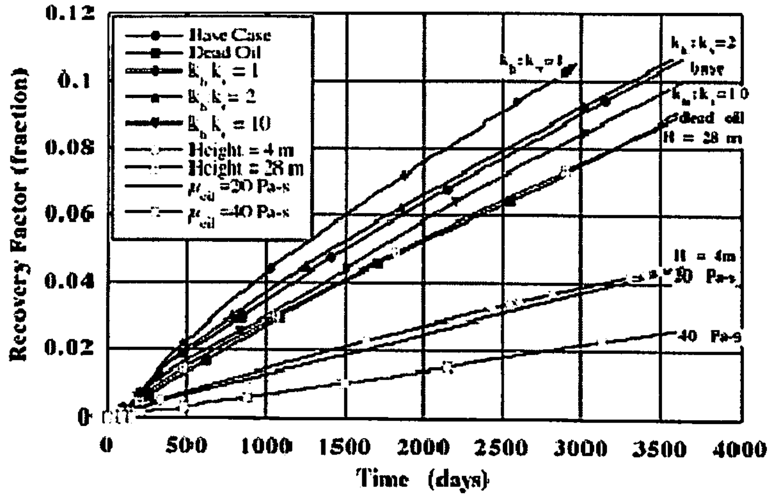


Figure 23 Sensitivity Analysis: Result of the Simulation Run (Time vs Recovery Factor)

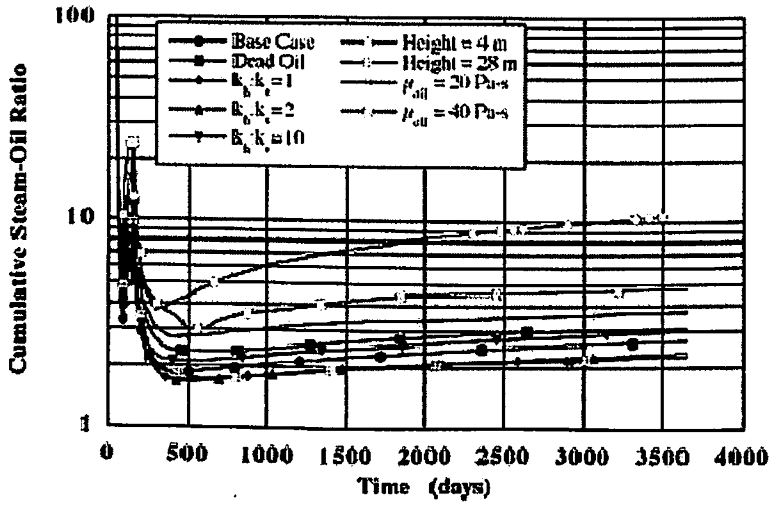


Figure 24 Sensitivity Analysis : Result of the Simulation Run (Time vs CSOR)

3.3.11 INJECTOR TO PRODUCER SPACING

For a better distribution of steam, a separation of 30m was introduced between the producer and injector sections of the well.

Equations:

1. The Darcy velocity of a volume of steam (u_v) flowing upward above the horizontal injection section is given by

$$u_v = -\frac{k_v k_{rs}}{\mu_s}\Delta\rho g$$

2. The Darcy velocity in the horizontal direction (u_h)

$$u_h = -\frac{k_h k_{rs}}{\mu_s}\frac{dp}{dx}$$

3. The time required for the particle to travel to the top of the formation (t_v) and from the injection section to the production section (t_h) are given by

$$t_v = \frac{h}{u_v}$$

$$t_h = \frac{L}{u_h}$$

If the t_v:t_h ratio is larger than one, then the time required for a particle to travel to the top of the reservoir is larger than the time required to travel to the production section. Therefore, we expect a large amount of steam short-circuiting.

Conversely, if the t_v:t_h is close to 1, we would expect limited steam short-circuiting, better steam flow through the reservoir, and increased steam chamber growth.

Substituting the Darcy velocity equations into the characteristic time equations :

$$\frac{t_v}{t_h} = \frac{h}{L}\frac{k_h}{k_v}\frac{\frac{dp}{dx}}{\Delta\rho g}$$

We approximate dp/dx as

$$\frac{dp}{dx} \tilde{n} \frac{\Delta p}{L} = \frac{p_{inj} - p_{prod}}{L}$$

$$\frac{t_v}{t_h} = \frac{h}{L^2} \frac{k_h}{k_v} \frac{(p_{inj} - p_{prod})}{\Delta \rho g}$$

For the base case of the sensitivity analysis and using the properties displayed in Table 4, <u>we calculate a t_v:t_h value of 12</u>

Parameter	Value
H	19.6 m
L	30 m
Kh	3400 md
Kv	800 md
Pinj	3230 kPa
Pprod	2230 kPa
Oil density	950 kg/m^3
Steam density	42.6 kg/m3
g	9.8 m/s2

Figure 25 Injector to Producer Spacing : Well and Reservoir Data

Thus due to the kv/kh ratio being 12, there is a less tendency of the steam to flow upwards.

To quantify the effect of sensitivity analysis, and to ascertain the effect of greater distance between the production and the injection sections of the well, *additional simulation runs were conducted.*

Calculations based on separation sizes of 60, 90, and 120 m were examined. These distances corresponded to t_v:t_h of 3.0, 1.3, and 0.75, respectively. In all cases, the length of the injection and production regions is the same only the distance between the two changes.

Recovery factor and CSOR histories for these calculations are given in Figures 18 and 19.

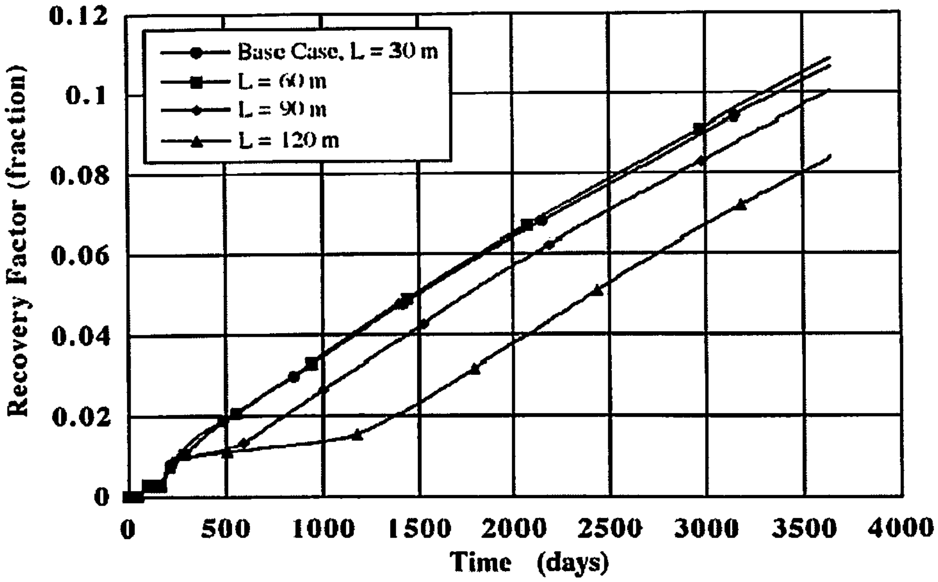


Figure 26 Variation in recovery factors with distance between the injector and producer sections

The trend can be seen. The recovery decreases as the distance between injector and producer increases.

The recovery factor for the 30 m separation distance is 10.4 % whereas that for the 90 m separation is 9.7%.

3.3.12 CONCLUSIONS

i. For an improved early time performance of a SW-SAGD project, the better the heating of the area, the better the results would be.

ii. CSS application preceding the actual SAGD, appears to be the most thermally efficient early-time heating method. Uniform heating along the length of the wellbore appears achievable with cyclic steam injection.

iii. Despite different initial procedures, the oil production rates after several years of steam injection are all very similar.

iv. Direct application of heat to a dead cold well would never lead to a good thermal efficiency of the process.

v. The results of the sensitivity analysis here indicate that SW-SAGD is most applicable to heavy oils with initial viscosity below 10,000 cP. . Thin oil zones prove to be the least desired candidates for performing a SW-SAGD job..Also, the reservoir must be sufficiently thick to allow significant vertical steam chamber growth.

vi. The sensitivity analysis also indicates that the presence of relatively small amounts of solution gas aids the recovery process by enhancing volumetric expansion of the oil on heating.

3.4 CASE IV

Quantitative analysis of MEOR: A Three Dimensional Numerical Simulation Study

3.4.1 Mathematical formulation Equations:

The mathematical formulation is written to describe multiphase flow through porous media.

1. The flow equation for oil, water and gas as follows:

Water:

$$\left[\frac{kk_{rw}}{\mu_w B_w}\Phi_w\right] + q_w = \frac{\partial}{\partial t}\left[\phi\frac{S_w}{B_w}\right] . \qquad (1)$$

Oil:

$$\left[\frac{kk_{ro}}{\mu_o B_o}\Phi_o\right] + q_o = \frac{\partial}{\partial t}\left[\phi\frac{S_o}{B_o}\right] . \qquad (2)$$

Gas:

$$\left[\frac{kk_{rg}}{\mu_g B_g}\Phi_g + \frac{R_{sw}kk_{rw}}{\mu_w B_w}\Phi_w + \frac{R_{so}kk_{ro}}{\mu_w B_w}\Phi_o\right]$$

$$+ q_g + q_w R_{sw} + q_o R_{so}$$

$$= \frac{\partial}{\partial t}\left[\phi\frac{R_{sw}S_w}{\mu_w B_w} + \phi\frac{R_{so}S_o}{\mu_o B_o} + \phi\frac{S_g}{B_g}\right] \ . \qquad (3)$$

2. The bacterial transportation can be described by the following equation:

$$\left[\frac{C_{wb}kk_{rw}}{\mu_w B_w}\Phi_w\right] + q_w C_{wb} = \frac{\partial(\phi S_w \rho_w C_{wb} + \sigma)}{\partial t} \ . \qquad (4)$$

3. The bacterial capture kinetics is given by following equation:

$$\frac{\partial \sigma_{np}}{\partial t} = -\alpha(u_{np} - u_c)\sigma_{np} + \beta C \ , \qquad (5)$$

$$\frac{\partial \sigma_p}{\partial t} = -(\delta + \rho\sigma_p)u_P C \ , \qquad (6)$$

and

$$\phi_i \sigma = \phi_i f \sigma_p + (1 - f)\sigma_{np} \ , \qquad (7)$$

Where volumetric flux densities in the pluggable and no pluggable pathways are related through respective permeabilities:

$$\frac{u_p}{u} = \frac{k_p(\sigma_p)}{k_p(\sigma_p) + k_{np}(\sigma_{np})} \ , \qquad (8)$$

Where 'u' denotes volumetric flux density in any given direction.

4. Permeability damage is expressed through the following empirical relationship:

$$k_p \approx k_{pi} e^{-a\sigma_p^4} , \qquad (9)$$

and

$$k_{np} \approx \frac{k_{npi}}{1 + \varepsilon \sigma_{np}} . \qquad (10)$$

5. In the nutrient transport, there are several considerations. Very often, carbon and mineral sources are required to support the growth and metabolic activities of bacteria. It is assumes that blocking of porous channel takes place by exponential growth of bacteria. This is given by:

$$C_t = C_o \, e^{\mu t} , \qquad (11)$$

Where C_t is the concentration at time t and C_o is the initial concentration.

Reservoir simulation runs were conducted in order to simulate following cases:

1. Bacterial growth and plugging through biomass.
2. IFT- reduction surfactant generation.
3. Oil viscosity – reducing surfactant generation.
4. CO_2 generation.

3.4.2 Result of Simulator run

Bacterial Plugging

The first series of numerical simulations run was conducted using single phase fluid.

- Both injection and production rates (assumed) = 50 $m^{3/}d$ for all these cases.
- All these runs are conducted assuming 20% pore volume of bacteria injected, followed by nutrient injection and then by chase water.

This was done to investigate the extent of bacterial plugging in a three-dimensional case. The single phase enabled to understand the permeability variation by comparison. Bacterial plugging may occur by two ways:

1. Shear multiplication of the number of bacteria.
2. The generation of polymer in situ.

a. In the present work, the first case is modelled. The results from a linear core analysis and the result of the simulator run were compared. These results are extrapolated on the basis of pore volumes of fluid injected. **Figure** shows that comparison. First, note the difference between the results of one – dimensional and three – dimensional modeling. All the parameters except dimensionality were kept constant for these two cases.

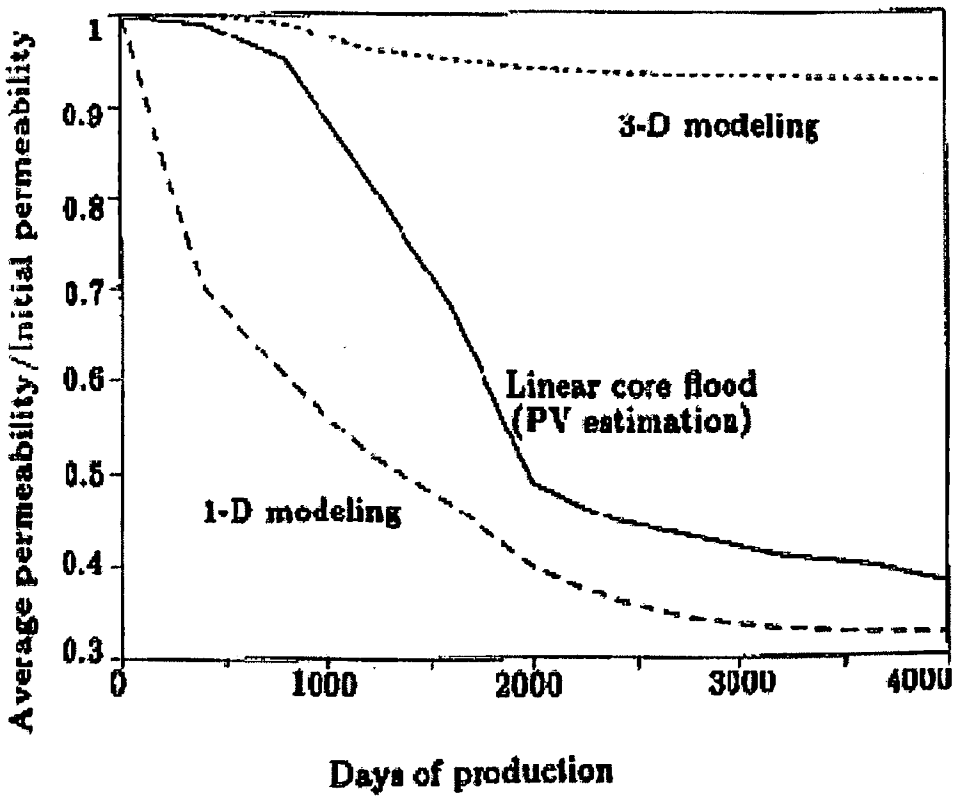


Figure 27 Difference between the 1-D modelling and 3-D modelling

In **one dimensional analysis,** the bacterial plugging occurs quickly in the first block and reduces the permeability to such an extent that further fluid injection leads to continuing bacterial build – up in first few blocks. This reduces overall permeability drastically.

In **three dimensional modeling,** the problem of local plugging is overcome and overall permeability reduction is much lower than what is obtained by one dimensional modeling. Also, three dimension modeling correctly tracks the path of nutrients, which do not necessarily follow that of bacteria.

b. The effect of in situ polymer generation is modeled by simply using higher growth rate of bacteria. **Figure** shows the effects of μ_m = 6.5/ hr on permeability loss.

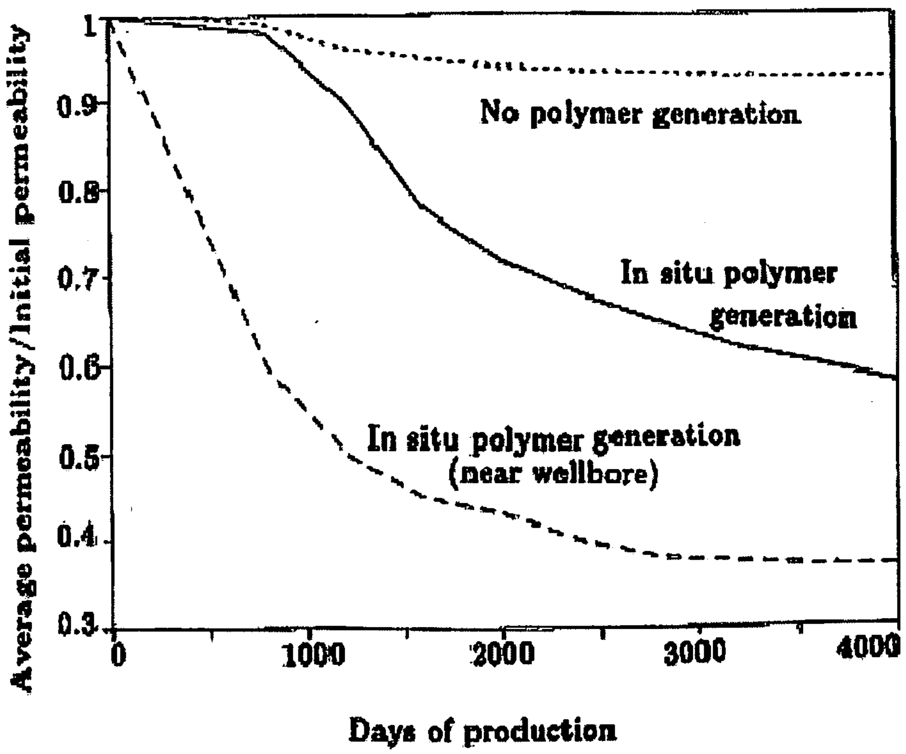


Figure 28 Comparison of permeability reduction due to bacteria injection and polymer generation

As can be seen from this figure, substantial permeability loss is observed for this case. This effect is more intense for the near well bore permeability reduction. A low near well bore permeability may lead to injectivity problem in a field situation.

c. The effect slug size of bacteria solution on permeability reduction for the case of polymer generation is shown in **Figure**. A 5% slug does not appear to give any appreciable permeability reduction. In a three dimensional case, 5% bacteria solution leads to a relatively small surface area to be in contact with the nutrient solution, which follows the bacteria. Consequently, nutrients find only a limited amount of bacteria in order to trigger bacterial growth and consequent plugging.

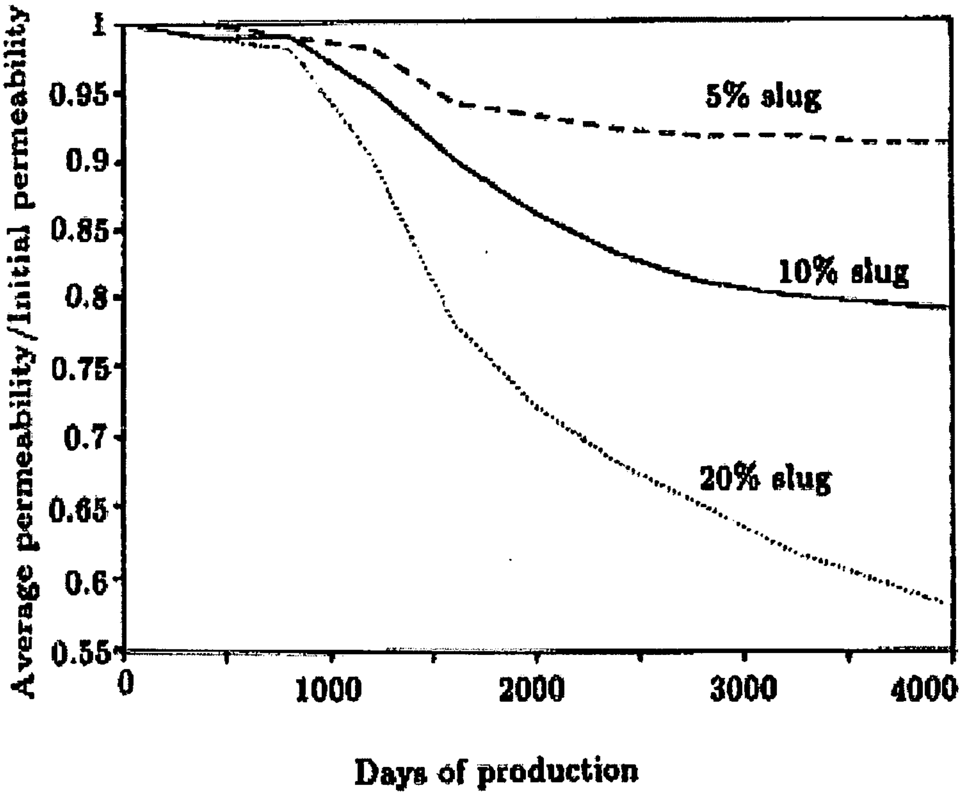


Figure 29 Effect of slug size on permeability reduction due to polymer generation

IFT Reduction

In order to model bacteria- generated surfactant flood, it is assumed that interfacial tension (IFT) as a function bacteria concentration. **Figure** shows the IFT vs bacteria concentration curve. Also, the relative permeability curves were related to IFT values in the following manner:

$$k_{ro} = k_{ro}(S_o) + [S_o - k_{ro}]\frac{\sigma_{max} - \sigma(C_b)}{\sigma_{max}}, \quad (12)$$

$$k_{rw} = k_{rw}(S_w) + [S_w - k_{rw}]\frac{\sigma_{max} - \sigma(C_b)}{\sigma_{max}} \quad (13)$$

In this formulation, it is assumed that the relative permeabilities to water and oil are straight line (extending from 0 to 1) when the **IFT, σ,** is zero. As IFT approaches 0, these relative permeability curves approach straight line forms.

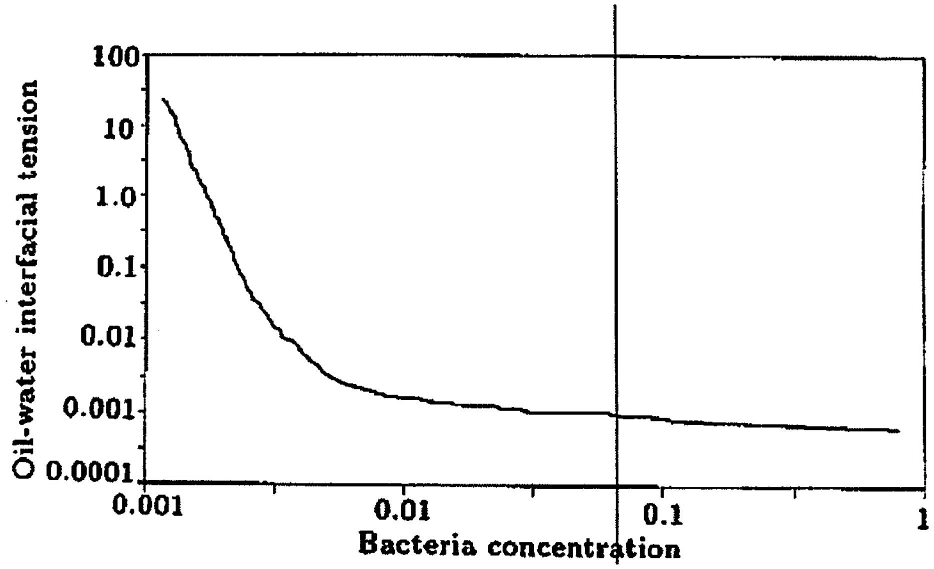


Figure 30 Correlation of bacteria concentration vs oil-water interface tension

Also, following capillary pressure curves were used in order to incorporate dependence of the **capillary pressure on σ(C_b):**

$$p_c[\sigma(C_b)] = p_1 p_c(\sigma_{max}, S_w).[\sigma(C_b)/\sigma_{max}] \ , \quad (14)$$

Where, p_c becomes 0 if σ is 0.

Initial reservoir conditions and saturations are given **in Table 2.** In order to compare results, a base case of water flooding was carried out. Similar to the field practice, surfactant – generating bacteria were injected following water flooding when the oil cut was less than 5%.

Table2. Reservoir model parameters

Table 13 Reservoir Model Parameters

Grid block in x-direction	20
Grid block in y-direction	20
Grid block in z-direction	10
Porosity	30%
Permeability, x-direction	$5 \mu m^2$
Permeability, y-direction	$5 \mu m^2$
Permeability, z-direction	$1 \mu m^2$
Oil viscosity	10 mPa.s
Water viscosity	1 mPa.s
Oil/Water IFT	30 dynes/cm
S_{wi}	40%

A very low oil cut was obtained after 2400 days, at which time bacteria injection was initiated.

To minimise the effect of bacterial plugging, a **.002/cm of deposition was assumed.**

The total **production constraint** of **50 m^3/ day was assumed.**

A **20% pore volume** of bacteria solution was injected. /

The **injection rate** was kept constant at **50 m^3/ day** for all the cases.

Results of water flood and bacteria injection are compared in **Figure.**

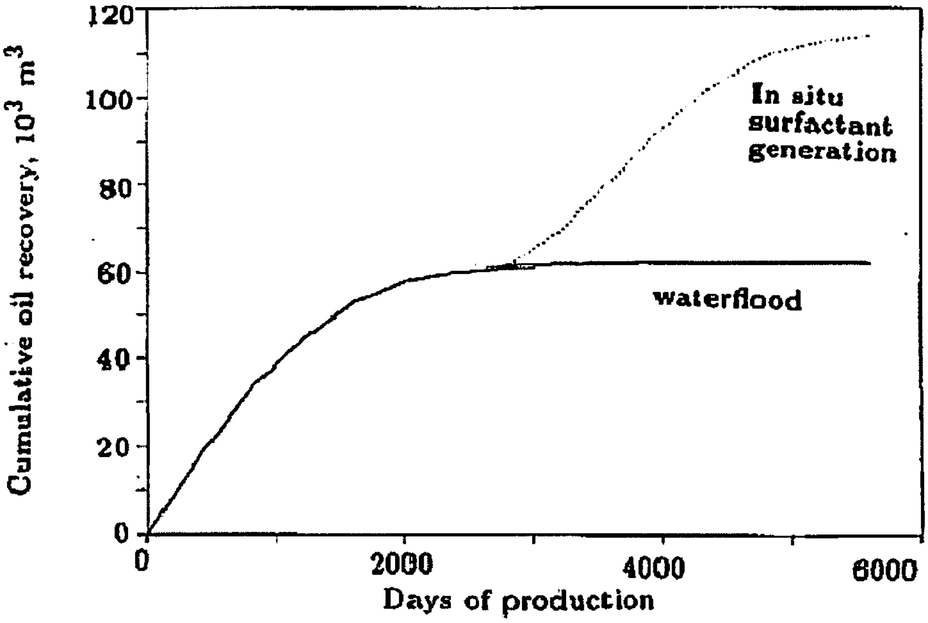


Figure 31 Comparison of oil recovery between bacteria generated surfactant flood and water flood

An incremental oil recovery of some 50.10 m^3 is observed clearly. This can be attributed to the sudden increase in the recovery when the bacteria surfactant reaches the production well. Earlier to that, there was no increase in the recovery due to the late contact between the bacteria and the oil.

This is an **improvement of 80% over a conventional** water flood.

Thus it can be seen, that *bacterial surfactant flooding can be used as an improved waterflood technique to improve recovery.*

A final run of surfactant – generating bacteria was conducted **in huff and puff mode.**

One well was used.

Bacteria rate of injection = 50 m^3/ day for 10 days,

followed by nutrient injection at 50 m^3/ day for 10 days.

Following this the well was closed for 20 days prior to production.

Similar to the previous case, post water flood conditions were used as the initial conditions for the bacteria injection.

An average cut of **60%** was obtained for a total of 600m3 of oil. Several cycles of operation were conducted. As the process progressed, the oil cut decrease gradually.

This result is shown in fig.

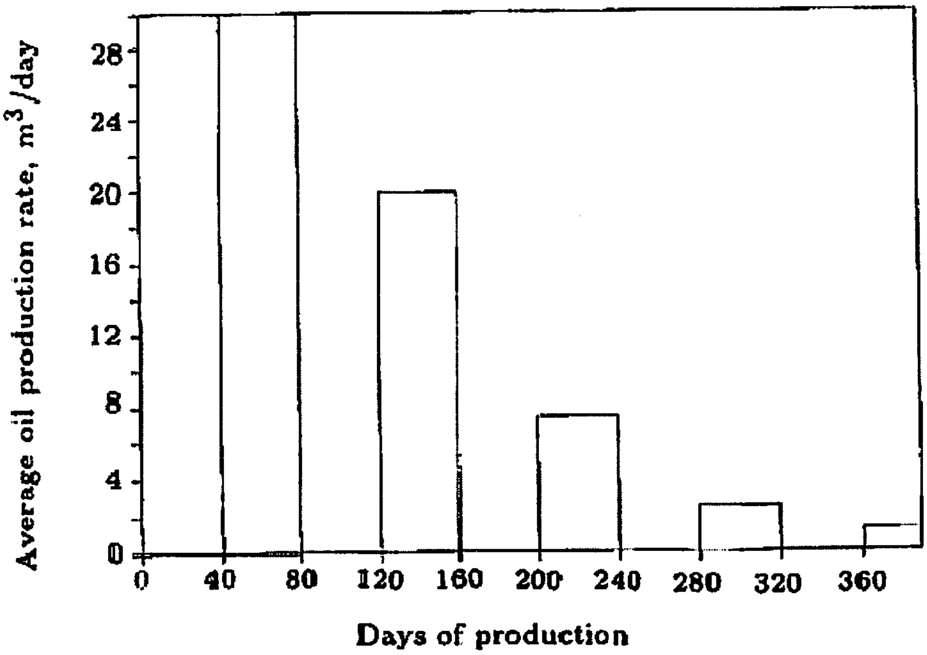


Figure 32 Oil flow rate of Huff and Puff with bacteria generated surfactant

These results indicate that even though huff and puff has much quicker response time than does the drive process, total incremental oil recovery is considerably smaller for this case.

Bacterial Conc vs Viscosity

Viscosity = 50 mPa.s.

This viscosity can be decreased considerably in the presence of bacteria. However, no conclusive experiment has been conducted to find out how oil viscosity correlates with bacterial concentrations. By analogy to solvent flood, a μ_o vs. bacteria concentration curve, as in Figure 18, is proposed for present study.

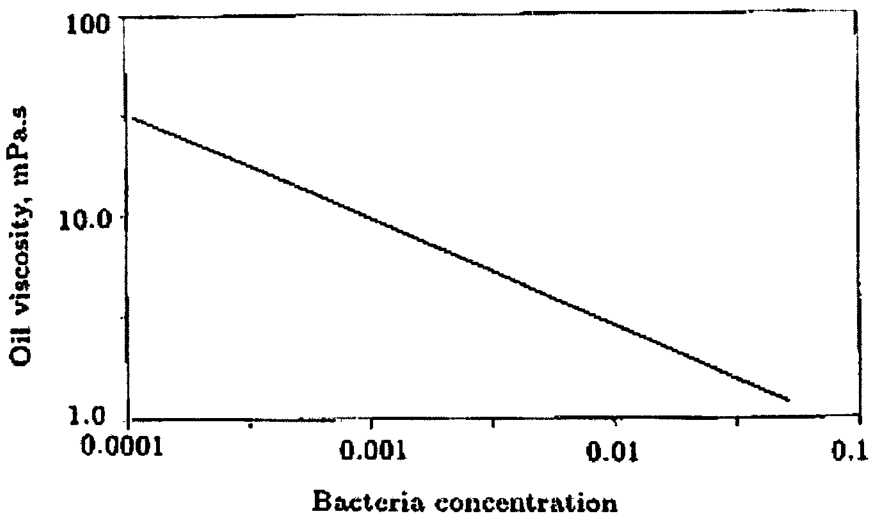


Figure 33 Correlation of oil viscosity vs bacteria conc

A comparative analysis of *waterflood vs bacterial effect* is shown. The main difference between the two curves is the delay in water breakthrough for the case of bacteria injection.

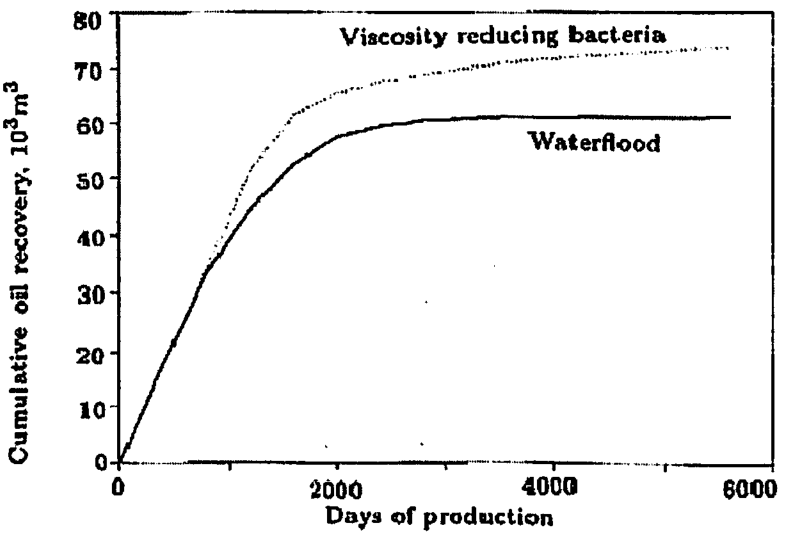


Figure 34 Comparison of recovery between viscosity reducing bacteria and waterflooding

Around 15,000 m^3 of additional oil can be seen as recovered.

Decreasing IFT is a much better way to enhance the recovery percentage. This can be seen by the above curve, though as compared to the viscosity reduction by the normal waterflood operation, this appears to be a better method.

CO_2 generation vs Bacterial Conc

The final run was conducted to simulate performance of CO_2- generating bacteria. An assumption of the correlation between bacteria and CO_2 volume was assumed.

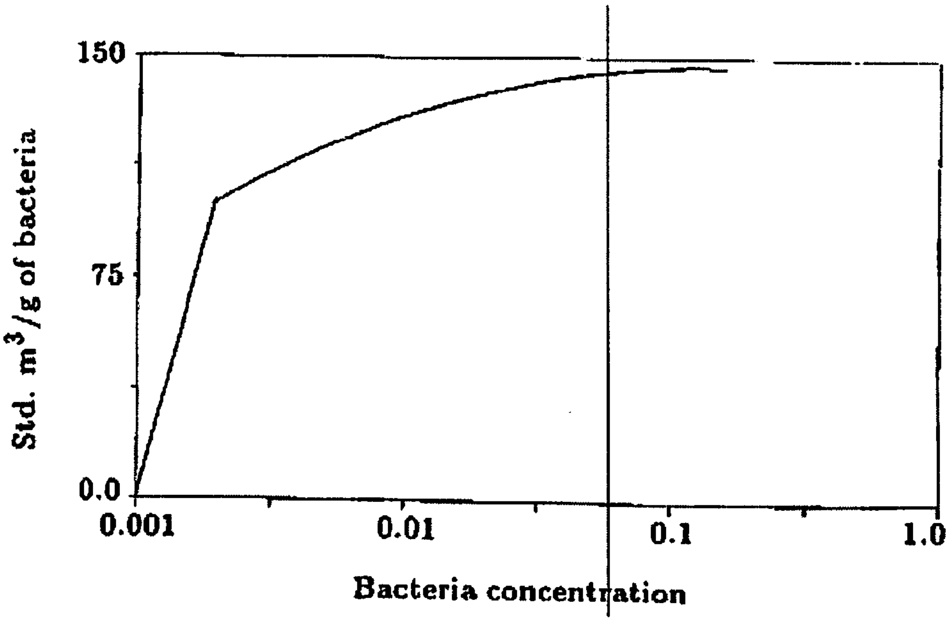


Figure 35 Correlation of CO2 generation vs. bacterial concentration

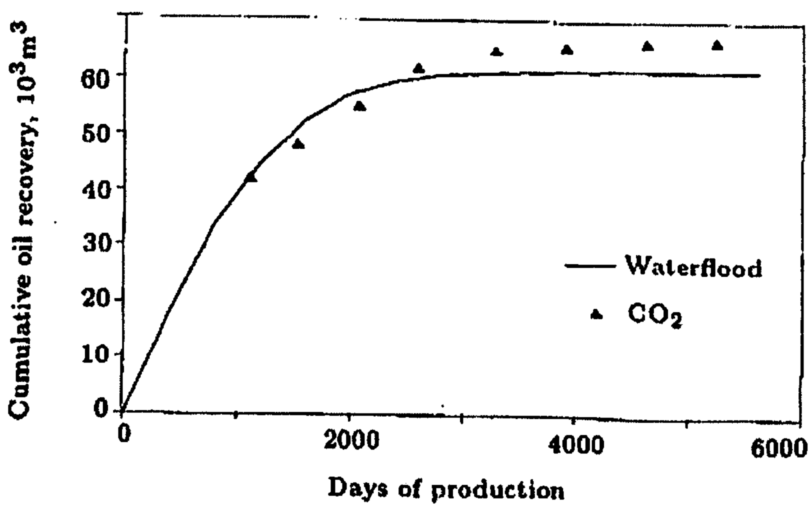


Figure 36 Comparison between bacterial generated CO2 injection and water flood

- In order to eliminate the numerical problem of the appearance of gas phase, a continuous gas phase was assumed existent in the reservoir (at 15%).
- $R_s = 50\ m^3/m^3$
- P = 300 psi as in the present case. Fig compares results of CO_2 generation with water flooding.
- Bacteria injection = 20% pore volume of the slug and was followed by continuous nutrient injection. This lead to increasing bacteria population and the generation of large amount of CO2.
- However comparing to the previous results, CO2 generation were not very encouraging. **In any case, the bacteria - generated CO_2 appears to recover as much oil as an immiscible CO_2 and water would.**

3.4.3 The Effect of Salinity and Temperature

Introduction

The present work aimed at investigating the effect of temperature and salinity on oil recovery by employing two types of bacteria:
Bacillus subtilis & Bacillus licheniformis.

Medium	: Sand Pack Column
Nutrient	: Sucrose
Experimental Temperature Range	: 40 - 70°C
Experimental Salinity Range	: 0 – 10000 NaCl

The column was mounted horizontally under 15 bars during shut-in period (3 days).

Results show that for both of the bacteria which were used in this investigation at different salinities *the microbial recovery efficiency decreased with increasing the temperature.* The maximum recovery for B. subtilis was 27% of water flood residual oil saturation at 40oC and 0% of salinity while for B. licheniformis was occurred (33.9%) at 40oC and 5% NaCl. In the present project, the effect of temperature and salinity on oil recovery by bacteria was investigated in sand pack column. The final goal of our study is to identify the best condition of each bacterium for MEOR processes.

Material

Bacillus subtilis and Bacillus licheniformis were preferred to use in this investigation.

OIL: °API = 21

Procedure:

The sand packed column was flooded with CO_2 and then 5 volumes of brine with pH = 7 was flown through it. then column was flooded with oil until residual water saturation was reached. The column then flooded with the same brine until no more oil was observed in the effluent. The flow rate was 10 ml/min. 0.2 PV of bacterial solution (5× 108 cells/ml) was injected to the column followed by 0.2 PV of nutrient (2% sucrose, 0.01% $(NH_4)_2HPO_4$).
Nitrogen was used to maintain a pressure of 15 bar.

The control column was flooded with the same brine and the same flow rate was used. Oil viscosity was measured before and after shut-in period.

Results

The calculations for the variations of temp and salinity with the recovery is shown in Table 3.

Effect of Temperature:

B. subtilis (especially at low concentration of salinity)

It is shown that recovery at different salinities **decreased with increasing the temperature, i.e. inversely proportional,** from 40°C to 70°C for all of the bacteria.

B. licheniformis (especially at high concentration of salinity)

It shows a **great potential at 40°C for MEOR** processes and their abilities to releasing the oil at 55°C are relatively acceptable.

No considerable potential was observed for application of both bacteria in reservoirs with temperature close to **70°C**.

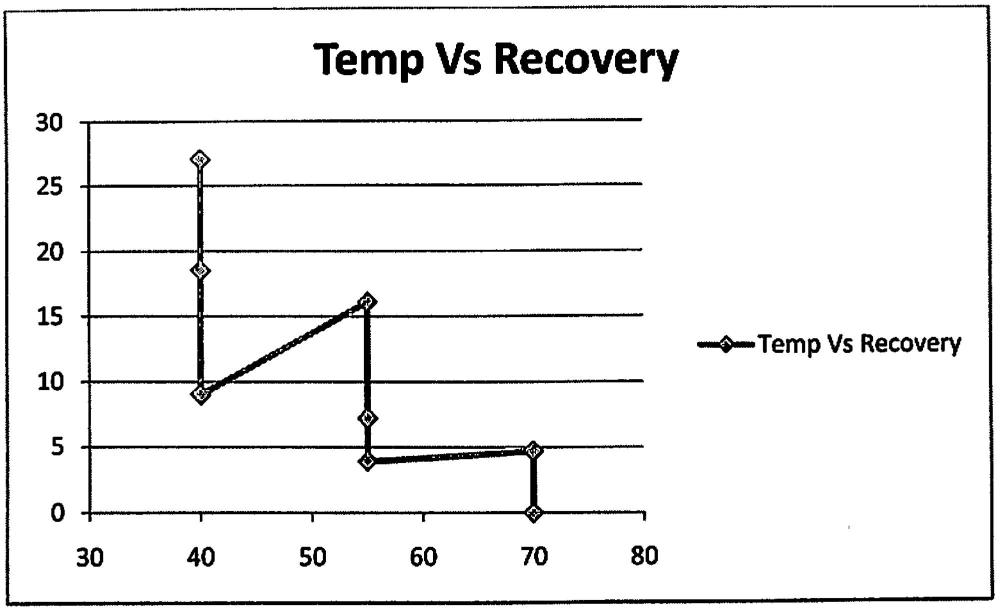


Figure 37 Calculated result of Temp vs Recovery of 1st Bacteria

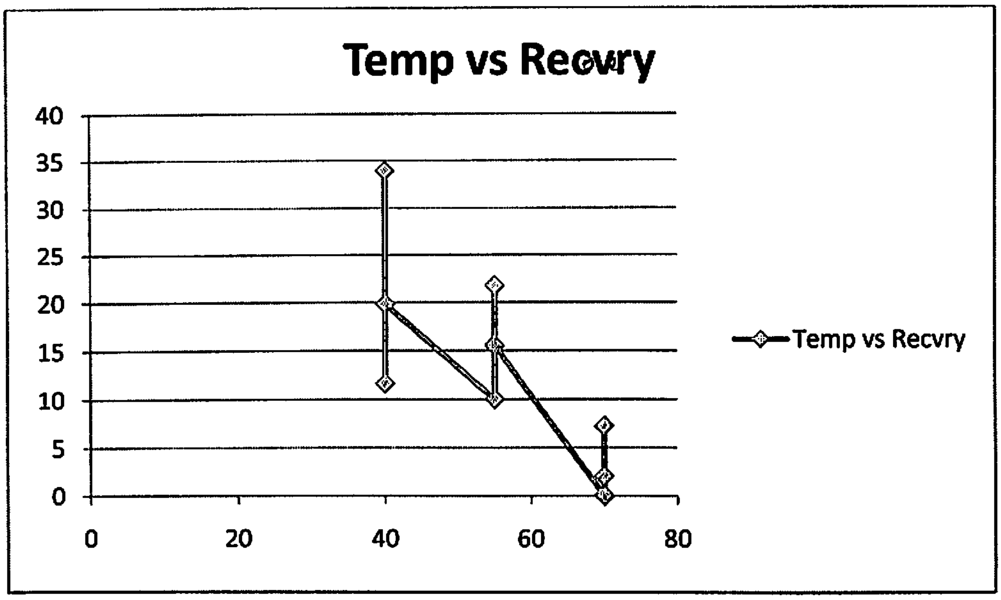


Figure 38 Effect of Temp on recovery for 2nd bacteria

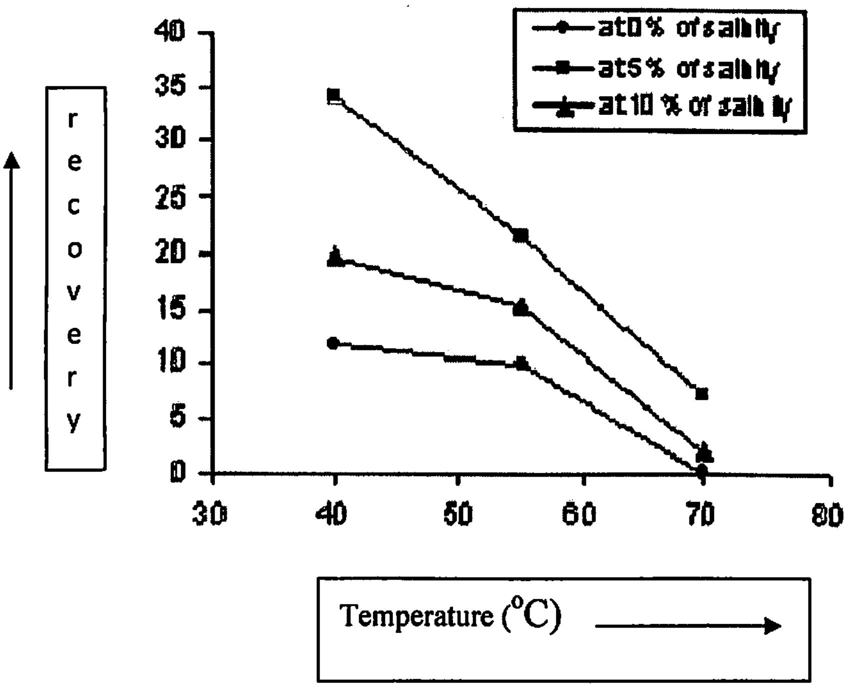


Fig.23 Effect of Temperature on recovery for Bacillius Licheniformis

Effect of Salinity:

The effects of salinity on at different temperatures for both of the bacteria were given in Fig. 24, 25. The figures illustrate that the microbial recovery for B. subtilis decreases with increasing the salinity from 0 to 10 % NaCl. But the maximum microbial recovery for B. licheniformis was achieved at 5% of salinity.

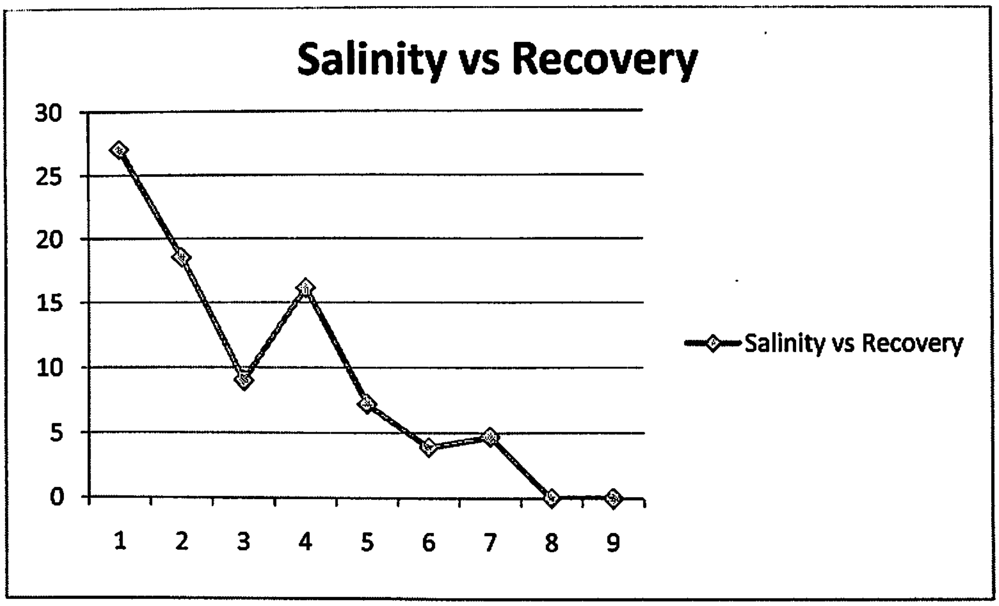
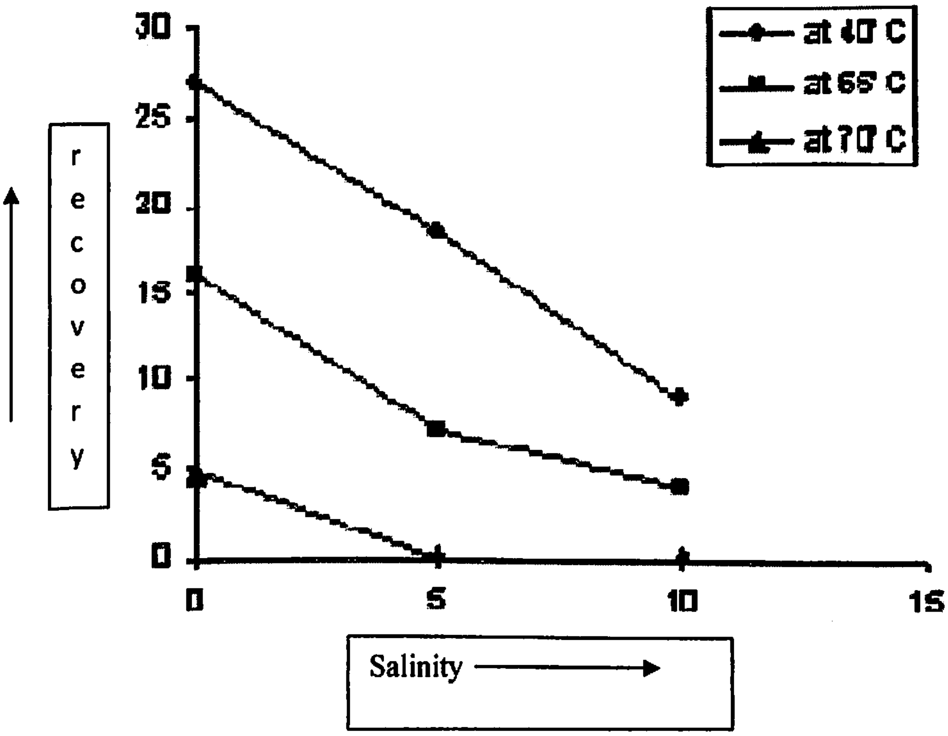


Figure 39 Calculated result of effect of Salinity vs Recovery of 1st bacteria



Effect of Salinity on recovery for Bacillius Subtilis

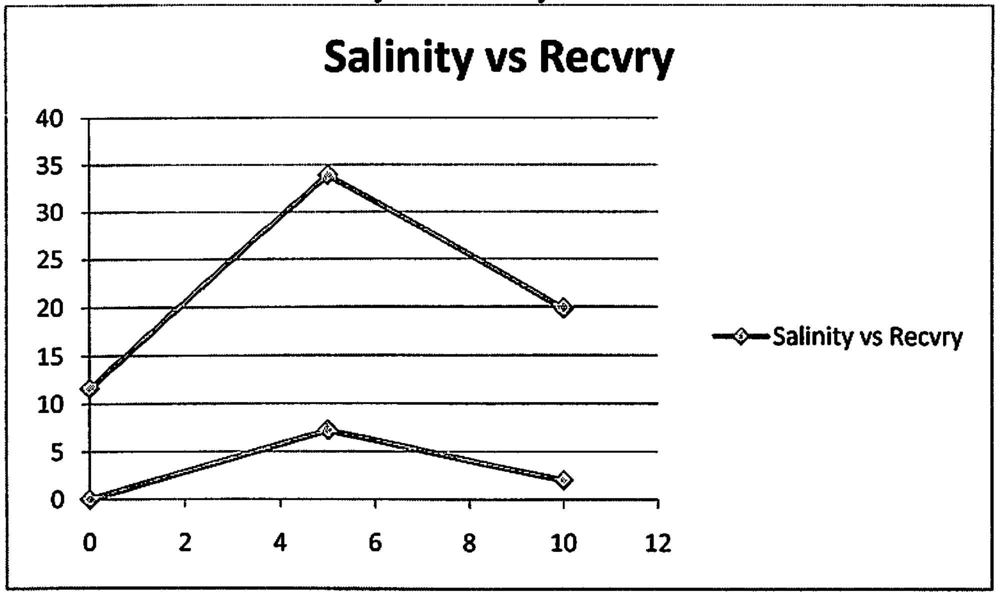
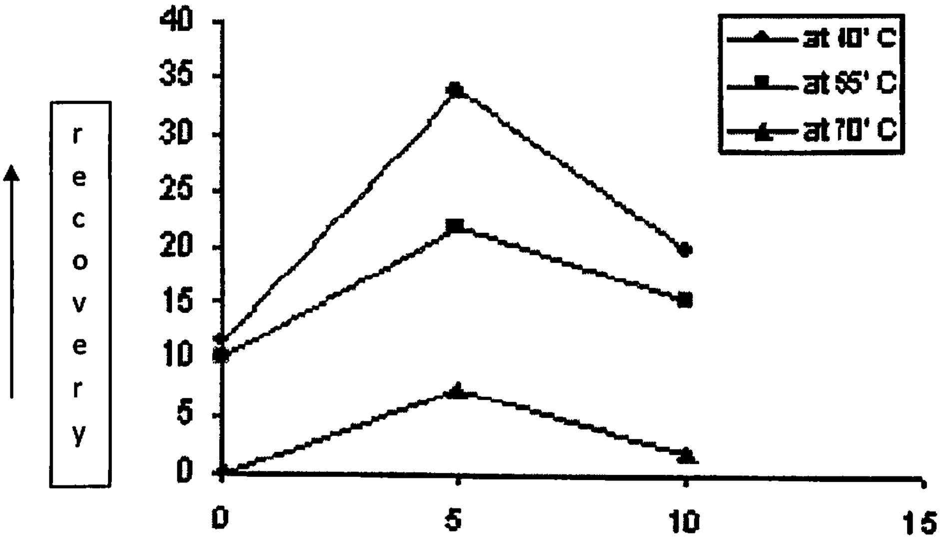


Figure 40 Calculated Result of Salinity vs Recovery for 2nd bacteria



Effect of Salinity on recovery for Bacillius Licheniformis

Salinity →

3.4.4 Calculations

Table 14

Ex. No.	Bacteria	Temp (^oC)	Salinity (w/v, Nacl)	Φ (%)	K_{abs} (D)	S_{ooip} (% PV)	S_{orwf} (% PV)	Water flood oil recovery (% PV)	S_{ormf} (% PV)	E_r (% PV)	μ_r %
1	B. Subtilis	40	0	33.0	33.7	80.1	56.4	29.6	41.1	27.0	26.6
2	B. Subtilis	40	5	33.7	31.1	78.0	56.9	27.0	46.3	18.5	15.9
3	B. Subtilis	40	10	36.6	37.2	79.3	57.8	27.1	52.5	9.0	8.0
4	B. Subtilis	55	0	34.5	44.6	71.1	46.9	34.0	39.3	16.1	19.3
5	B. Subtilis	55	5	34.5	35.1	69.3	43.5	37.1	40.3	7.2	-
6	B. Subtilis	55	10	35.8	39.7	69.7	44.0	36.8	42.2	3.9	-
7	B. Subtilis	70	0	36.6	41.9	66.1	35.5	46.3	33.8	4.7	-
8	B. Subtilis	70	5	35.8	43.8	61.9	33.7	44.7	33.7	0	-
9	B. Subtilis	70	10	35.0	34.0	63.9	35.1	45.1	35.1	0	-
10	B.Licheni.	40	0	37.0	31.5	83.2	58.0	30.2	51.2	11.6	11.8
11	B.Licheni.	40	5	36.6	39.1	79.9	59.0	26.1	40.0	33.9	31.8
12	B.Licheni.	40	10	35.8	43.0	78.5	57.3	27.0	45.9	19.8	22.5
13	B.Licheni.	55	0	36.6	32.1	68.4	43.9	35.8	39.5	10.0	4.3
14	B.Licheni.	55	5	34.5	37.6	70.1	45.4	35.2	35.5	21.7	18.9
15	B.Licheni.	55	10	34.0	42.0	70.8	44.2	37.5	37.3	15.5	9.6
16	B.Licheni.	70	0	35.8	41.7	63.8	37.0	41.9	37.0	0	-
17	B.Licheni.	70	5	37.0	39.7	61.6	34.0	44.8	31.5	7.2	-

18	B.Licheni.	70	10	34.5	33.1	64.5	36.5	43.3	35.7	2	-

Figure 41 Calculations for recovery

Where;

S_{ooip} = original oil in place

S_{orwf} = Residual oil saturation after water flooding

S_{ormf} = Residual oil saturation after microbial flooding

μ_{bm} = Oil recovery before shut in period

μ_{am} = Oil recovery after shut in period

E_r = Microbial recovery efficiency;

μ_r = Viscosity reduction;

3.4.5 Conclusion:

Several conclusions can be drawn from the results:

- For low concentrations of salt, the FIRST BACTERIUM , i.e. Bacillus subtilis would be more suitable as from the curves plotted, it can be seen that **the microbial recovery efficiency decreases with the increasing salinity and temperature.**
- The microbial recovery efficiency for SECOND BACTERIUM, **Bacillus licheniformis** decreased with increasing temperature from 40°C to 70°C while its maximum takes place at 5% NaCl, **making it suitable for microbial enhanced oil recovery in relatively high salty reservoirs.**

1. The **Newtonian Index (NI)** is used to evaluate the shifting from shear rate sensitive (pseudoplastic) behaviour toward a more Newtonian fluid.

$$NI := \left[\left[\frac{\left[\left(\mu app^{control}\right)^{minSR} - \left(\mu app^{control}\right)^{maxSR}\right]}{\left(\mu app^{inoculated}\right)^{minSR} - \left(\mu app^{inoculated}\right)^{maxSR}}\right]\right]^{TMD}$$

The comparison between control and inoculated oil samples is evidence of microbial cracking by each different culture. **To test as positive, NI needs to be greater than 1.10.**

2. **The Delta Viscosity (DV) Index** is used to measure the global change in viscosity in the explored range of shear rates. **To test as positive DV need to be greater than 0.10.**

$$DV := \left[\frac{\sum_{i=minSR}^{maxSR}\left(\mu app_i\right)^{control} - \sum_{i=minSR}^{maxSR}\left(\mu app_i\right)^{inoculated}}{\sum_{i=minSR}^{maxSR}\left(\mu app_i\right)^{control}}\right]^{TMD}$$

3. A simple version of Enhanced Oil Recovery factor (EOR Index) is obtained, by direct mathematical manipulation of DV index, as related only to viscosity contribution. **An exceeding EOR value from 1.15 tests as positive**

$$EOR := \frac{1}{(1 - DV)}$$

4. The Darcy velocity of a volume of steam (u_v) flowing upward above the horizontal injection section is given by

$$u_v = -\frac{k_v k_{rs}}{\mu_s} \Delta\rho g$$

5. The Darcy velocity in the horizontal direction (u_h)

$$u_h = -\frac{k_h k_{rs}}{\mu_s} \frac{dp}{dx}$$

6. The time required for the particle to travel to the top of the formation (t_v) and from the injection section to the production section (t_h) are given by

$$t_v = \frac{h}{u_v}$$

$$t_h = \frac{L}{u_h}$$

Substituting the Darcy velocity equations into the characteristic time equations :

$$\frac{t_v}{t_h} = \frac{h}{L} \frac{k_h}{k_v} \frac{\frac{dp}{dx}}{\Delta\rho g}$$

We approximate dp/dx as

$$\frac{dp}{dx} \approx \frac{\Delta p}{L} = \frac{p_{inj} - p_{prod}}{L}$$

$$\frac{t_v}{t_h} = \frac{h}{L^2} \frac{k_h}{k_v} \frac{(p_{inj} - p_{prod})}{\Delta\rho g}$$

7. The flow equation for oil, water and gas as follows:

Water:

$$\left[\frac{kk_{rw}}{\mu_w B_w}\Phi_w\right] + q_w = \frac{\partial}{\partial t}\left[\phi\frac{S_w}{B_w}\right] . \tag{1}$$

Oil:

$$\left[\frac{kk_{ro}}{\mu_o B_o}\Phi_o\right] + q_o = \frac{\partial}{\partial t}\left[\phi\frac{S_o}{B_o}\right] . \tag{2}$$

Gas:

$$\begin{aligned}\left[\frac{kk_{rg}}{\mu_g B_g}\Phi_g + \frac{R_{sw}kk_{rw}}{\mu_w B_w}\Phi_w + \frac{R_{so}kk_{ro}}{\mu_w B_w}\Phi_o\right]&\\ + q_g + q_w R_{sw} + q_o R_{so}&\\ = \frac{\partial}{\partial t}\left[\phi\frac{R_{sw}S_w}{\mu_w B_w} + \phi\frac{R_{so}S_o}{\mu_o B_o} + \phi\frac{S_g}{B_g}\right] .&\end{aligned} \tag{3}$$

8. The bacterial transportation can be described by the following equation:

$$\left[\frac{C_{wb}kk_{rw}}{\mu_w B_w}\Phi_w\right] + q_w C_{wb} = \frac{\partial(\phi S_w \rho_w C_{wb} + \sigma)}{\partial t} . \tag{4}$$

9. The bacterial capture kinetics is given by following equation:

$$\frac{\partial \sigma_{np}}{\partial t} = -\alpha(u_{np} - u_c)\sigma_{np} + \beta C \ , \qquad (5)$$

$$\frac{\partial \sigma_p}{\partial t} = -(\delta + \rho\sigma_p)u_P C \ , \qquad (6)$$

and

$$\phi_i \sigma = \phi_i f \sigma_p + (1-f)\sigma_{np} \ , \qquad (7)$$

Where volumetric flux densities in the pluggable and no pluggable pathways are related through respective permeabilities:

$$\frac{u_p}{u} = \frac{k_p(\sigma_p)}{k_p(\sigma_p) + k_{np}(\sigma_{np})} \ , \qquad (8)$$

Where 'u' denotes volumetric flux density in any given direction.

10. Permeability damage is expressed through the following empirical relationship:

$$k_p \approx k_{pi} e^{-a\sigma_p^4} \ , \qquad (9)$$

and

$$k_{np} \approx \frac{k_{npi}}{1 + \varepsilon\sigma_{np}} \ . \qquad (10)$$

11. In the nutrient transport, there are several considerations. Very often, carbon and mineral sources are required to support the growth and metabolic activities of bacteria. It is assumes that blocking of porous channel takes place by exponential growth of bacteria. This is given by:

$$C_t = C_o \ e^{\mu t} \ , \qquad (11)$$

Where C_t is the concentration at time t and C_o is the initial concentration.

the relative permeability curves were related to IFT values in the following manner:

$$k_{ro} = k_{ro}(S_o) + [S_o - k_{ro}]\frac{\sigma_{max} - \sigma(C_b)}{\sigma_{max}} \quad (12)$$

$$k_{rw} = k_{rw}(S_w) + [S_w - k_{rw}]\frac{\sigma_{max} - \sigma(C_b)}{\sigma_{max}} \quad (13)$$

following capillary pressure curves were used in order to incorporate dependence of the **capillary pressure on σ(C_b):**

$$p_c[\sigma(C_b)] = p_1 p_c(\sigma_{max}, S_w).[\sigma(C_b)/\sigma_{max}] \quad , \quad (14)$$

$$Er = \frac{S_{orwf} - S_{orwf}}{S_{orwf}} \times 100$$

$$\mu_r = \frac{\mu_{bm} - \mu_{am}}{\mu_{bm}} \times 100$$

Chap 5 Conclusions & Recommendation

The project encompasses the theoretical analysis of MEOR and SAGD in great extent along with the best possible integration of their numerical studies. With the project limitations mentioned at the beginning, an attempt was made by the author to interpret various case studies.

The experience of Oil India Ltd. (OIL) of a MEOR job during 2005-2008 in Barail Sand of was illuminated. The net oil gain by the job was determined and the variation of the productivity due to variation of the reservoir parameters. A pilot test of an Argentina crude was studied to elaborate on the concepts of sensitivity analysis and variation of recovery with changing reservoir parameters.

With the advent of techniques of the likes of MEOR and SAGD in the industry, new windows have been opened for extracting the 377 billion barrels of untapped oil present.

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