

SPE 69652

Waterflooding Optimization Using Biotechnology: 2-Year Field Test, La Ventana Field, Argentina

Alejandro Maure, Forrest Dietrich (Microbes Inc.), Ulises Gómez, Javier Vallesi, Marcelo Irueta (REPSOL-YPF).

Copyright 2001, Society of Petroleum Engineers Inc.

This paper was prepared for presentation at the SPE Latin American and Caribbean Petroleum Engineering Conference held in Buenos Aires, Argentina, 25–28 March 2001.

This paper was selected for presentation by an SPE Program Committee following review of information contained in an abstract submitted by the author(s). Contents of the paper, as presented, have not been reviewed by the Society of Petroleum Engineers and are subject to correction by the author(s). The material, as presented, does not necessarily reflect any position of the Society of Petroleum Engineers, its officers, or members. Papers presented at SPE meetings are subject to publication review by Editorial Committees of the Society of Petroleum Engineers. Electronic reproduction, distribution, or storage of any part of this paper for commercial purposes without the written consent of the Society of Petroleum Engineers is prohibited. Permission to reproduce in print is restricted to an abstract of not more than 300 words; illustrations may not be copied. The abstract must contain conspicuous acknowledgment of where and by whom the paper was presented. Write Librarian, SPE, P.O. Box 833836, Richardson, TX 75083-3836, U.S.A., fax 01-972-952-9435.

Abstract

Bio-technology improved water flood performance during a two-year test in Victor Claro reservoir layers C2-D2, La Ventana field, northern Cuyo Basin, Mendoza Province, Argentina (Figure 1, 2 and 3). Paraffinic oil has been produced by waterflooding since 1989. The objective is determination of the technical and economical feasibility of Microbial Enhanced Oil Recovery (MEOR) methods for field-wide application in mature water floods. This pilot results from and continues studies of controlled microbial colonization in producer wells begun in La Ventana field in 1995.

Fluid property alterations were evaluated using a complete set of rheology parameters, specific geochemical fingerprints and bio-assays on more than 82 samples from La Ventana and neighboring fields. The oil proved to be highly bio-treatable and formation water is compatible with MEOR requirements. Reservoir rock properties and pressure-temperature status were also positive.

The Microbial Inoculation Program started December 1998 and was implemented by systematic treatment of injected water using hydrocarbon degrading anaerobic-facultative microorganisms on a non-regular injection pattern having direct influence on four neighboring producers (Figure 4). A complementary tracer field test using Tritium permitted validation of inter-well connectivity and allocation factors initially inferred by the use of streamline simulation. Pre- and Post-MEOR fractional flow field performance in producers was

also correlated with theoretical predictions using a proprietary 2D, vertically integrated, streamline simulator. The tracer and simulations aided in comprehension of MEOR mechanisms and in determining bio-treatment design.

Original oil production decline rates have improved. Increments in oil cut were measured using conventional methods for 24 months after MEOR program initiation (Figure 19). Two mechanisms combined account for this behavior: further depletion of residual oil saturation by in-situ production of metabolites with low interfacial tension and improved oil mobility from short-chain solvents originated by microbial alteration of heavy paraffinic ends. Further evaluations will cover extension of pilot period and the analysis of economic feasibility for large-scale MEOR implementation in other zones under conventional flooding.

Introduction

Today exists worldwide experiences describing MEOR methods and field applications as technical, cost effective and competitive with conventional EOR methods (Ref.: 1 to 6).

The objective in La Ventana case is determination of the technical and economical feasibility of Microbial Enhanced Oil Recovery (MEOR) methods for field-wide application in correlation with mature waterflood applications.

The evaluation program is oriented to develop VC incremental reserves and also to expand to Punta de las Bardas South, Punta de las Bardas/Vacas Muertas Lobe South and Vacas Muertas North areas producing from the rest of active reservoirs (Figure 3).

MEOR references in northern Cuyo Basin

Tupungato-Refugio MEOR Project

This project was initiated on June 1994 in three wells producing from Conglomerado Rojo Inferior, named C.R.I. (corresponding with BRC denomination in La Ventana Field, Barrancas Fm.) and Victor Oscuro Member (Rio Blanco Fm.) formations. Average production per well is 90 BOPD at 63% water cut. As result of 14 months of combined monthly and bi-weekly

microbial treatments the incremental oil due to MEOR resulted in 19,000 barrels (19% increase over baseline), [Ref. 1.]

Piedras Coloradas MEOR Project

The program started March 1997 and continued during twelve non-consecutive months. Six producer wells, two of them horizontals were under a systematic program of inoculations using hydrocarbon-degrading anaerobic-facultative microorganisms. The field produces from two separate reservoirs: Conglomerado Rojo Inferior, named C.R.I. (in correspondence with BRC denomination in La Ventana Field, Barrancas Fm.) and Victor Oscuro Member (Rio Blanco Fm.). Incremental Oil averages 66% over baseline with minimum values of 28.5% and maximum above 110%, [Ref. 4].

La Ventana Field

General Description and MEOR Background

La Ventana, discovered in 1957 is located in Argentine Republic (South America), 70 km southwest of the city of Mendoza (Figure 1).

It is the most prolific field of the Cuyo Basin. Its cumulative oil production as of October 2000 amounts 429 MMBO ($68.2 \times 10^6 \text{ M}^3$). It is located in the central trend of productive fields of the basin, between Rio Tunuyan and Vizcacheras fields. The La Ventana block comprises two separate fields (Figure 3) called La Ventana in the lower structural position of the block and the main field composed by two subparallel noses, which pinch out at the structure top called Vacas Muertas/Punta de las Bardas Area. These fields produce from the Barrancas and Rio Blanco formations, which can be subdivided in four main reservoirs as follows: the TRC (Top Red Conglomerate) and BRC (Bottom Red Conglomerate) in the Barrancas formation and the VC (Victor Claro) and LRB (Lower Rio Blanco) in the Rio Blanco formation (Figure 2).

Structurally the Cuyo basin is an extensive NW-trending depocenter that is limited by extension faults, which were subjected to several tectonics movements.

La Ventana block has a total of 230 producers. Current oil production is 11950 BOPD ($1900 \text{ M}^3/\text{D}$) and 214 MBWPD ($34000 \text{ M}^3/\text{D}$) of co-produced water. The field has mature waterflooding projects since 1969 with more than 80 injector wells injecting 226 MBWPD ($36000 \text{ M}^3/\text{D}$) in the three reservoirs. The difference between produced and injected water (12600 BWPD , $2000 \text{ M}^3/\text{D}$) is captured from a neighbor field (Rio Tunuyán).

TRC Reservoir

Geology: The TRC, The upper member of the Barrancas formation, is the most extensive reservoir of La Ventana Field. It is composed of grain-supported and matrix-supported sandstones and siltstones, deposited by braided streams in proximal rivers subject to flood stages. This environment is characterized by a

widespread distribution of its conglomerates bodies frequently are in contact due to "cut and fill" phenomenon.

History: The TRC reservoir was first placed on production in December 1958. A total of 405 well have reported production from the reservoir. The water injection in the TRC was initiated in 1968. The cumulative production through October 2000 is 230.2 MMBO ($36 \times 10^6 \text{ M}^3$) and the cumulative water injected amounts 729 MMBW ($116 \times 10^6 \text{ M}^3$). The current average production rates of the TRC are 4474 BOPD ($711 \text{ M}^3/\text{D}$), 116211 BFPD ($18477 \text{ M}^3/\text{D}$), 96% WC, through 126 active producers. The injection rate is 86800 BWPD ($13801 \text{ M}^3/\text{D}$), through 29 active injectors.

BRC Reservoir

Geology: The BRC is the lower member of the Barrancas formation. It is composed of conglomerates grain and matrix-supported sandstones and siltstones, interpreted as fluvial and debris flow deposits. The basal zone of the BRC is more continuous, with fair to good permeability. The upper part has poor continuity and poorer reservoir characteristics.

History: The BRC reservoir was first placed on production in January 1959. A total of 290 well have reported production from the reservoir. The water injection in the BRC was initiated in 1977. The cumulative production through October 2000 is 84.4 MMBO ($13.4 \times 10^6 \text{ M}^3$) and the cumulative water injected amounts 523 MMBW ($83.1 \times 10^6 \text{ M}^3$). The current average production rates of the BRC are 3808 BOPD ($605.4 \text{ M}^3/\text{D}$), 61290 BFPD ($9745 \text{ M}^3/\text{D}$), 94% WC, though 142 active producers. The injection rate is 93100 BWPD ($14802 \text{ M}^3/\text{D}$), through 53 active injectors.

LRB Reservoir

Geology: The LRB, the lower member of the Rio Blanco formation, is the smallest reservoir of the field. It is composed by sandstones and tuffs intercalated with shales. In the southern part of Punta de las Bardas area it has been subdivided in four parasequences, which show a high vertical heterogeneity and fair to poor lateral continuity, due to faults or permeability barriers.

History: The LRB reservoir started producing in 1966, but the main development of Punta de la Bardas was carried out in 1992. A total of 19 wells have reported production from the reservoir. A pilot waterflood project was implemented in the LRB in 1999. The cumulative production through October 2000 is 2.2 MMBO ($3.4 \times 10^5 \text{ M}^3$), and the cumulative water injected amounts 293 MBW ($46.5 \times 10^3 \text{ M}^3$). The current average production rates of the LRB are 313 BOPD ($49.7 \text{ M}^3/\text{D}$), 2733 BFPD ($434.5 \text{ M}^3/\text{D}$), 89% WC, through 13 active producers. The injection rate is 960 ($152.6 \text{ M}^3/\text{D}$) BWP, through 1 active injector.

VC Reservoir

Geology: The VC, the upper member of the Rio Blanco formation, is a complex multichannel reservoir. Its facies are composed by gravels and sandstones intercalated with shales which represents a fluvial-flood plain assemblage of facies. The VC sands have an irregular geometry with a variable range of continuity and petrophysical properties in the different areas of the field.

History: The VC reservoir was first placed on production in January 1962. A total of 223 wells have reported production from the reservoir. The water injection in the VC sands was initiated in 1969. The cumulative production through October 2000 is 89.9 MMBO, ($14.3 \times 10^6 \text{ M}^3$) and the cumulative water injected amounts 201.4 MMBW ($32.0 \times 10^6 \text{ M}^3$).

The current average production rates of the VC are 2591 BOPD (411 M^3/D), 40981 BWPD (6515 M^3/D), 94% WC, through 103 active producers. The injection rate is 31370 BWPD (4987 M^3/D), through 26 active injectors.

VC accounts for 22% of the La Ventana block production and receive 13% of total injected water.

Positive oil bio-treatability indexes and favorable petrophysic parameters were primary factors to select two sands of VC reservoir (D2-C2) as target for a systematic Microbial Inoculation Program (Figure 3 and 4). The pattern pertain to Punta de las Bardas field.

All of the four reservoirs are produced by gas expansion and small natural water drive as primary mechanism of drainage and are strongly assisted by artificial water flooding. Water injection projects involve all reservoirs in Barrancas and Rio Blanco formations.

La Ventana MEOR Project in producer wells

The first evaluation started in 1995 by covering microbial inoculations and lab screening in 8 producer wells producing from three reservoirs as follow:

- BRC
PB-67 (*), PB-172(*), PB-194, LV-21(*), PB-82
- TRC
PB-204, PB-177, PB-194, LV-21, PB-82
- VC
PB-33

Note: (*) Field inoculated

And it was extended with minor modifications from July 1996 on a final cluster of five wells from BRC, TRC and VC reservoirs:

PB-172 (BRC, Hydraulic)

VM-95 (LBRC, Hydraulic)

PB-136 (TRC, SRP)

PB-33 (VC, Hydraulic)

PB-109 (VC, D2-C2, Hydraulic)

The result was concluded as technically positive (specially in well PB-109) but cost and labor intensive due to the fact that the majority of La Ventana producers are mainly operated by an oil-

powered hydraulic extractive system. The operative situation was an encouraging factor to analyze MEOR feasibility oriented to waterflooding schemes. Since past October, 2000 the operator is executing a conversion program to turn the hydraulic system to PCP, SRP and ESP.

MEOR in Waterflooding Schemes: Conceptual frame

Microbial Enhanced Oil Recovery (MEOR) technology is based on the systematic inoculation of producing and/or injecting wells with hydrocarbon-degrading anaerobic-facultative microorganisms and complementary nutrients. The primary goal of the method is to extensively colonize the porous medium of the oil bearing. [Ref.: 1 to 6]

There are two main procedures to colonize a target reservoir (Figure 14):

1) Treating producer wells, by pumping downhole periodic microbial batches in order to reach the near wellbore porous space via tubing or annulus of the producers draining such reservoir. This methodology is usually referred as simply MEOR. The microbial effect in treated wells could be detected in two consecutive stages: A) Clean-up effects by the removal of organic damage occurring in the near wellbore of the perforated interval, opening non-productive zones bearing oils with a more segregated, heavy and pseudoplastic behavior. This effect produces a high peak in oil rate but only for a limited time. B) Permanent rheological effects by the compositional alteration occurring at deeper colonization radius, in drainage zones with extremely low shear rate values (low fluid velocity). This effect is the most important MEOR objective to pursue in treated producers, as this improvement is sustainable for a long period if proper microbial inoculation schedule is continued.

2) Treating injector wells, by-introducing the microbial treatment via the injectors. In this case the treatment uses the injected water as carrier to introduce colonizing microorganisms into active streamtubes of flooded space of the target layers. This is frequently termed as MEOR², because it is usually used in combination with the simultaneous treatments in injectors and producers described in point 1. Compared with the first approach, the advantage of treating injection schemes is mainly becoming from the potential size of colonized zones, bigger residence time and the role of multiple improving recovery mechanisms: 1) Rheology alteration of moveable oil in active streamtubes and its direct dependence in fractional flow with oil/water mobility ratio. 2) Depletion in residual oil saturation (S_{or}) by In-Situ production of biosurfactant. 3) Conformance efficiency improvements created by the colonizing biomass in active streamtubes that diverts fluids to unflooded zones.

Microbial System used in MEOR

Seven different microbial sub-communities (grouped by functionality as microbial products) of highly motile, synergetic, symbiotic microorganism consortia were initially used to test La

Ventana oil biotreatability. The 17 strains used to formulate the symbiotic blend are naturally occurring anaerobic-facultative bacteria capable of deriving nourishment from linear hydrocarbons.

A combination of microorganisms is necessary to adjust the bacterial community to specific substrates (oils), improving mechanisms and reservoir conditions. Microbial products are also conditioned to have an adequate balance in C/N and C/P ratios and type of complementary nutrients, buffers, trace elements (K^+ , Na^+ , Mg^{++} , Ca^{++} , $Fe^{++/+++}$, Zn^{++} , Co^{++}) and biocatalyzers, since formation water usually lacks sufficient nitrogen and phosphorous.

Primary objectives of this stage are to stabilize enzymatic reactions at water/oil interfaces in the productive formation, in order that such biochemical action can modify oil mobility, by the generation of solvents and bio-surfactants.

The proof of these alterations and consequent modifications is accomplished by serial Rheological Lab Procedures (Annex A) in combination with Organic Geochemistry Methods (Biomarkers and GC-MS Chromatography, Annex C).

The change in amount and compositional characteristic of produced fluids arises as a consequence of microbial action on saturated portion of hydrocarbon substrates (Table 1) under anaerobic conditions. It is accompanied by a strong modification on N/P ratio in the colonized poral volume. Changes in micro-environmental parameters existing in poral space promote specific metabolic paths that ultimately produce the biocracking on linear and branched paraffin compounds, which are present in abundance in La Ventana oil (Figures 5, 6). The expected result is the shifting in molecular weight and chain length toward a lower range and greater compositional homogeneity. The most significant evidence is the viscosity reduction at low shear rates and the shift in pour and cloud temperature points (Figures 12 and 13, Annex A).

Candidate injection patterns were selected having producers from only the target reservoir (VC, Rio Blanco fm.), avoiding treatment of multilayer systems, with different petrophysical parameters.

Water Flooding Optimization approach in La Ventana Field

Motivation

The optimization of waterflooding schemes is usually tackled by adding chemically active substances to the injection water. Despite that they are effective at lab conditions, it is difficult to reach sustainable levels of functional entities (mainly by dilutive effects and degradation) at extreme conditions (temperature, salinity, indigenous biota, etc.).

The motivation to explore the use of biotechnology in waterflooding schemes is based on the fact that active bio-compounds (surfactants, polymers, solvents, etc.) with impact on

EOR mechanisms could be derived by direct metabolization of existing hydrocarbons by the colonizing biomass. The biomass thriving at the water/oil interface in the poral space needs to be supplemented with a proper N/P (Nitrogen to Phosphorous) relation for optimal growth. Due to that N and P are below one or two order of magnitude of C requirements, it is possible to assist pattern-size biorreaction volumes (essentially the water phase in the poral volume associated with the floodable portion of the pattern) by introducing the proper microbial system (inoculum) and reasonable amounts of N, P salts periodically with every treatment (Figure 14, 33). The metabolites (surfactants, polymers, solvents, etc.) are in direct relation with the concentration of living (sessile and planktonic) biota capable to be assisted by the treatment program. The co-current flow help to transport the nutrients faraway from the injection point. N/P is a controllable parameter for biota concentration along the colonized streamtubes (Figure 34, 35).

General Screening Criteria

Primary requirements to check are:

1. Crude oil composition must contain n-alkanes in sufficient amount and show little or no evidence of previous levels of biodegradation by indigenous micro biota.
2. Bottom hole temperature need to be less than 250 °F. Pressure is not a limiting factor.
3. Chlorides less than 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 (2 to 4 μm) to permit microorganism migration. This requirement means to have an "available window" in poral geometry to permit profound microbial incursion.

Fluid Evaluation, Oils

A complete set of rheology parameters, specific geochemical data, ionic patterns, fingerprints and biomarkers was used to evaluate pre- and post-trial compositional alterations in La Ventana reservoir fluids.

Geochemical background

In October 1996, The first Geochemical Analyses were performed on three oils from La Ventana field (PB-109 (VC), PB-172 (BRC) and VM-136 (TRC)). This report shows that oils are not having signals of biodegradation and was providing clear evidence that they could be good targets for a MEOR program in close agreement with results obtained in Tupungato and Piedras Coloradas pilot projects.

Main conclusions were [Ref.: 2]:

1. All three La Ventana oils belong to one oil family.
2. All are very paraffinic, undegraded oils that were sourced from a single source facies.
3. All geochemical parameters indicate a single oil type, with normal alkane distributions.

4. Pristane/Phytane ratios and to relation with normal homologous paraffins are particularly diagnostic oil-oil correlation parameters and biodegradation

Oil sample Id.	Prystane/nC ₁₇ Ratio	Phytane/nC ₁₈ Ratio
PB-109 (VC)	0.28	0.14
PB-172 (BRC)	0.27	0.14
PB-136 (TRC)	0.27	0.13

5. The oils show signs of water washing or biodegradation (especially PB-109 (VC) and VM-136 (TRC)).

Oil sample Id.	Toluene/nHeptane Ratio	nHeptane/MCH Ratio
PB-109 (VC)	0.10	1.05
PB-172 (BRC)	0.45	1.16
PB-136 (TRC)	0.09	1.12

6. An odd-carbon preference is discernable in the oils, in the medium range (C17, C19) n-alkanes, CPI averages 1.10 for the three oils. These preferences, together with the presence of C27 and C29 steranes suggest the oils were derived from both algal and terrestrial precursors.

MEOR-oriented geochemical studies

An additional independent geochemical laboratories was selected to confirm previous studies and to evaluate compositional alterations and their correlation with rheology parameter evolution [Ref. 10, 11, 12].

Conceptual basis and methodology

Changes in the composition of petroleum during a MEOR process can be tracked through analyses that are typically applied in the geochemical characterization of rock bitumen's and oils. These changes could occur at a bulk or molecular level, most likely both, and are difficult to anticipate: each oil type subjected to a specific microbial batch treatment reacts in a different manner under particular subsurface conditions. Moreover, these changes are time-dependant and several of them sequential, and could show up at very different times in non-related oils. A summary list of the analytical techniques applied to the geochemical characterization of oils can be found in Annex B. Short comments of the changes that could be expected after a MEOR process on particular oil are:

Liquid Column Chromatography is applied after precipitation of asphaltenes to determine the proportions of saturated hydrocarbons, aromatic hydrocarbons and resins + NSO (nitrogen, sulfur, oxygen) compounds. The naphthenes can be later estimated as a part of the saturates from the whole oil gas chromatography. These five fractions are expected to change after a MEOR process. Modification of API gravity should be related to the changes in the bulk composition of the oil.

Percent Sulfur is a typical bulk parameter of an oil, which will likely be modified after a MEOR process.

High Resolution Whole Oil Gas Chromatography typically allows determination of normal- and iso-paraffins (quantitatively, in ppm) and defines the "envelope" of an oil. Ratios between compounds and relations between ranges of compounds (light, medium, heavy) as well as the chromatogram baseline should change after a MEOR process. Figure 5, 6.

Gas Chromatography of the Saturated Hydrocarbon Fraction basically provides the same information as whole oil gas chromatography but is more precise in resolving peak co-elution and allows better ratio calculations. However, a big disadvantage is that during isolation of the fraction the light compounds <C15 are partially or totally lost.

Gas Chromatography of the Aromatic Hydrocarbon Fraction allows identification and quantification of the typical aromatic compounds present in oils: methyl-naphthalenes, dimethyl-naphthalenes, trimethyl-naphthalenes, phenanthrene, methyl-phenanthrenes and dimethyl-phenanthrenes. Relationships between these groups of compounds and between isomers could change after a MEOR process. Figure 7, 8.

Detailed C6-C7 Gas Chromatography. Twenty-five compounds are identified and quantified in the C6-C7 range through gas chromatography. The range is very sensitive to microbial attack and should experience changes after a MEOR process.

Stable Carbon Isotopes of Whole Oil, Saturates Hydrocarbon Fraction And Aromatic Hydrocarbon Fraction. The $\delta^{13}\text{C}$ values are bulk characteristics of oils. After a MEOR process the values could hypothetically show minor to significant modifications.

Gas Chromatography – Mass Spectrometry Of Saturates Hydrocarbons. The terpane and sterane biomarker fingerprints represent extraordinary valuable information in the characterization of an oil (source, thermal maturity, biodegradation). A MEOR process could very possibly modify molecular ratios and parameters of these fingerprints.

Gas Chromatography – Mass Spectrometry Of Aromatic Hydrocarbons. Similar to saturate biomarkers, the fingerprints of aromatic steranes are a supplement to the molecular characterization of an oil. In addition, the method allows quantification of 2- & 3-ring aromatic hydrocarbons (naphthalene, phenanthrene and dibenzothiophenes compounds).

Rheological studies

Conceptual basis. Oil as very complex substance exhibits typical non-Newtonian behavior (Figure 10). Viscosity is shear rate sensitive (pseudoplastic model) and its apparent value correlate with the fluid velocity field and capilar throat distribution and coordination geometry of poral chambers. The concept of constant viscosity in the drainage or area under flooding is no longer valid, rather "apparent" values are pertinent. Specific quantitative lab procedures were conducted to

measure the shift in rheological properties in treated (inoculated) and untreated (control) samples obtained from wellhead manifold for every candidate well.

Lab indexes and methodology. Serial assays were conducted to determine the alterability of Barrancas and Rio Blanco oils under systematic microbial influence (enzymatic cracking). Basically, lab procedures consisted of serial inoculations of oil with seven different microbial products, followed with a program of controlled atmosphere incubation at specific temperatures. Further examination of inoculated and control oil (originals) using full computational rotational viscometers, will be produced the necessary plots and data vectors to generate quantitative indexes. Deviations in $\mu\text{app.}[\text{mpa.s}]$ vs. Temperature [$^{\circ}\text{F}$] and $\mu\text{app.}[\text{mpa.s}]$ vs. Shear Rate [$1/\text{s}$] curves were the basis for calculating quantitative numbers describing the degree of compositional alteration. Mathematical expressions for these dimensionless indexes are described in Annex A. 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.

So, the **Newtonian Index (NI)** is used to evaluate the shifting from shear rate sensitive (pseudoplastic) behavior toward a more Newtonian fluid. The comparison between control and inoculated oil samples is evidence of microbial cracking by each different microbial culture. To test as positive NI need to be greater than 1.10. (Eq.1)

The **Delta Viscosity (DV) Index** measures the global change in apparent viscosity in the explored range of shear rates (minSR, maxSR). To test as positive DV need to be greater than 0.10. (Eq.2)

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

A data base of 82 oil samples from La Ventana and neighboring fields producing from Barrancas and Rio Blanco formations, pertaining to both structural axes of Cuyo sedimentary basin were tested to define general rheological properties of Mendoza North oils. First evaluations start on 1994. In general all these crude oils tested far above cut-off values, evidencing very good microbial treatability. Reference values in pre-selected oils were:

Sample	NI	DV	EOR
LV-21 (B.R.C), La Ventana	1.94	0.22	1.22
PB-161 (T.R.C.), P. de las Bardas	2.90	0.21	1.27
A-22 (V.C.) – Atamisqui	1.11	0.50	2.00
<u>Limit for positive testing</u>	<u>>1.10</u>	<u>>0.10</u>	<u>>1.15</u>

PB-220: Rheological Analysis for main productive formations

During the screening period of reservoir candidates was programmed the rig intervention of PB-220 producer (Punta de las Bardas field). The objective was oil sampling of every producing interval in order to evaluate rheological parameters vs. depth. The PB-220 has six different producing zones pertaining to LBRC, VC and LRB reservoirs with MEOR potential. The samples were collected and tested by comparative rheology for biotratibility.

The results were used to crosscheck vertical with Areal biotratibility indexes, permitting to individualize the best candidate sands for MEOR application.

Reservoir	Sand	NI	DV	EOR
LBRC	1,2,3	2.30	0.39	1.64
VC	D2	0.50	0.36	1.56
VC	C2	2.83	0.16	1.19
VC (LRB)	B3	1.31	0.14	1.16
VC (LRB)	B1	1.42	0.25	1.33
<u>Limit for positive testing</u>		<u>>1.10</u>	<u>>0.10</u>	<u>>1.15</u>

Fluid Evaluation, Water

Ionic pattern and salinity of formation water need to meet certain requirements to avoid side effects during the MEOR pilot test. Maximum limit in chlorides is considered safe when it has less than 100.000 p.p.m. PH is best near neutral. Blending water is also conditioned and monitored for total solid content and particulate size distribution (Figure 41).

Reservoir Selection oriented to microbial waterflooding optimization

To correlate MEOR performance with homogeneous fluid/rock systems it is convenient to select reservoirs being flooded separately from the rest and having homogeneous oil/rock parameters. In the screening process six patterns meeting this requirement were scrutinized:

Pattern	Reservoir	Active Layers	Producers
VM-75	BRC	B1,2,3	6
GBB-7	TRC	N/D	3
B-182	TRC	N/D	3
PB-115	VC-LRB	C2,B3,1	4
PB-191	VC	D2,C2	4
VM-80	BRC	LBRC1,2	5

For operative considerations only the PB-191 was considered acceptable for a sustainable MEOR program. As result of the rest of screening figures, the PB-191 pattern that injects recycled formation water in two sands (D2 and C2) of VC reservoir was pre-selected as the candidate for microbial flooding during a two-year program. The PB-191 started injection in August 1989. Figures 15 to 18 illustrate fluid production and injection histories.

MEOR target: VC Reservoirs, characteristics**Oils from Victor Claro reservoirs, PVT data (PB-53).**

Bubble pressure (psi):	574
Gas Oil Ratio (M^3/M^3):	84
Boi factor (M^3/M^3):	1.110 @2600 psi
Viscosity (cp, SR>20 s ⁻¹ , 180°F):	10 (Roll Ball viscometer)
API°:	29.0 (Reservoir condition)

VC reservoirs: Pattern Selection

The PB-191 non-regular injection pattern was finally selected from several injector candidates. This well has a selective installation (Figure 42) and is only injecting in two layers (D2-C2) of VC. There is not evidence of crossflow between mentioned sands. The PB-191 Injector is having direct influence on four neighboring producers: PB-83, PB-111, PB-212, PB-220 with good treatability parameters:

Sample	NI	DV	EOR
PB-116 (V.C.) as control	3.57	0.14	1.16
PB-109 (V.C.) as control	14.9	0.58	2.39
PB-83 (V.C.)	2.03	0.37	1.58
PB-212 (V.C.)	0.50	0.62	2.66
PB-220 (V.C.)	3.90	0.42	1.72
PB-111 (V.C.)	1.68	0.34	1.52
Limit for positive testing	>1.10	>0.10	>1.15

Main reasons behind this selection are:

1. Adequate number of producers to have sufficient statistical significance and good discrimination in well-by-well and global performance evaluation.
2. Non-marginal wells having consistent and clear fluid production histories. Production values (M3/day) at MEOR start are:

Well	Qo	Qw	Perforated at
PB-83 (V.C.)	5	108	Feb. 1983
PB-212 (V.C.)	7	18	July 1995
PB-220 (V.C.)	16	133	May. 1997
PB-111 (V.C.)	15	145	Apr. 1970
PB-109 (V.C.)	6	19	Feb. 1974

3. Capable of discriminating microbial stimulation and EOR improvements in corresponding with control variables for targeted reservoir (Rio Blanco Fm).
4. Wells producing oils with positive bio-treatability tests.
5. Adequate completion and extraction configuration.
6. Relevance to determining design consideration for future expansions.
7. Good petrophysical parameters: In general, the poral system in VC formation is favorable to microbial migration. Poral

throat distribution is controlled by the quantity and type of cement, which is related to the amount of tuff ashes between the grains. Pore geometry characteristics has distinctive matrix monomodal distribution with poral throat mean values centered at 10 μ m. Further evaluation has detected the presence of microscopic fractures. These small fractures, which are common in this tectonic framework contribute to the movement of fluids and permit migration of microorganism transversal and longitudinal to the flow paths direction in the reservoir.

VC petrophysical characteristics at PB-191 pattern

Figures 25, 26, 42 are for vertical reference and areal continuity. Tables 3, 4, 5 serve as comparative with the general parameters of active reservoirs

D2-C2 sands: Common petrophysical parameters

Kro(Swirr):	0.468
Krw(Sor):	0.203
Swirr (%):	41
Sor (%):	28
Porosity (%):	18.5
Absolute Permeability (md):	200
Depth (m.b.s.):	2249.2
Reservoir Temperature (°F)	230
Original Reservoir Pressure (psi):	2600
Present Reservoir Pressure (psi):	800
Bubble Pressure (psi):	574
GOR (M^3/M^3):	<30
Bo factor (M^3/M^3):	1.125
Viscosity (cp, SR>20 s ⁻¹ , 170°F):	10 (Roll Ball viscometer)
API° (Bottom Hole Conditions):	29.0

Victor Claro Fm., C2 Reservoir

Effective interval (pattern average):	3.6 m
Effective interval (at PB-191):	1 m
Allocation Factor for Injection Rate:	34%
Depth (m.b.s.):	2262.5

Victor Claro Fm., D2 reservoir

Effective interval (Pattern average):	4 m
Effective interval (at PB-191):	3.5 m
Allocation Factor for Injection Rate:	66%
Depth (m.b.s.):	2249.2

Pilot Design

Design of a pilot test is a complex process. To produce the best results in terms of degree of significance and discrimination it is necessary to integrate a multidisciplinary team in biotechnology, reservoir, production and complementary areas (rheology and geochemical topics). The main objective behind task design is to achieve technical closure and good levels of correlation between controllable and uncontrollable groups of variables. The controllable variables are mainly MEOR

treatment parameters. The uncontrollable variables are related with fluid and rock characteristics, which exert significant influence on MEOR response. Additional objectives are to confirm feasibility indexes exhibited during laboratory testing. The pilot was designed to measure microbial impact on Recovery Factor for the treated pattern for reservoir in exploitation.

A reasonable prediction capability between previous screening and post-MEOR results is another important objective. Discrimination in pre- and post-pilot data information and good "signal to noise ratio" is essential for a successful pilot. 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). Minimal time scale need to be a two-year period or at least 2 Poral Volume of cumulated water injected. Another important concept behind of pilot implementation is to reduce the uncertainty for all relevant measurement occurring during the pre- and post-MEOR stages. Finally, cost of pilot evaluation need to be consistent with expected benefits under different scenarios, risk and expansion strategies.

Pattern Selection

PB-191 non-regular injection pattern was selected from several candidates from different productive areas in La Ventana Block exploiting different reservoirs as was mentioned before. The PB-191 Injector has direct influence on four neighboring producers: PB-83, PB-111, PB-212, PB-220. The selection was based on:

1. Good connectivity between the injector and producers with not excessive interwell distances.
2. Regular pattern geometry like for instance inverted five or seven spot.
3. At least a ratio of four first line producers per treated injector
4. Consistent production and injection data during conventional waterflooding.
5. Wells producing oils with proven positive biotreatability tests and average petrophysical parameters for the target layers in selected reservoir.
6. Pattern located in zones with a simple structural description, avoiding macro-heterogeneities like faults or permeability barriers.
7. Adequate completion configuration for both producers and injector
8. Relevance to determining design consideration for future expansions.

Operative aspects

The inoculation program started December 1988 and continued for 24 consecutive months. VC reservoir under PB-191 waterflooding (four first line active producer wells), were

under a systematic program of inoculations using hydrocarbon degrading anaerobic-facultative microorganisms.

Treatments

PB-191 injector is equipped with selective injection in D2-C2 sands (Figure 42)

Treatment design centers on following items:

1. Method of inoculation based on injector completion and pressure conditions at wellhead. A quick entrance in fall-of conditions (when the injection ceases) is a good indicator
2. Good storages facilities to maintain safe the products from extreme wheater conditions (freezing temperatures, direct sunlight, etc)
3. Microbial community structure.
4. Concentration of complementary nutrients, salts, and biocatalyzers in order to assist the colonization. A variable amount of supplements and formulations was used in this case.
5. The global biotic concentration to use during periodic treatments (varying from 50 to 100 p.p.m.)
6. Quality control of microbial products based on CFU counts/ml. and biochemical profiles matricial assays help to maintain an optimum viability and to avoid contamination on storage drums. Serial samples for every concentrate need to be taken prior to formulate the blend at well location. The results permit to maintain an optimum quality in microbial products.
7. Blending water availability and stable ionic pattern of injected water.
8. Presence of competitive indigenous biota and chemical interference (SRB colonies and chemical biocides programs to mitigate them)
9. Microbial typologies according with EOR objectives (factory cultured)
10. Frequency of periodic inoculations.

Microbial inoculations in the injector were programmed every 7 days. The batch is formulated at well location with fixed amount (65 +/- 15 p.p.m.) of four basic microbial concentrates having a minimal activity of 10^6 Colonizing Forming Units per ml) but variable in terms of blending water (400 liters of diluting water). Note: Blending water was the injecting water taken from wellhead and checked for neutral PH, ionic profile and solid particulate content).

The blend of concentrates participate with a distinctive percentual structure according with oil/rock characteristics of VC reservoir. In PB-191 Pattern was used: EOR-BAC 1 (30%), EOR-BAC 4 (10%), EOR-BAC 5 (10%), EOR-BAC 6 (50%).

Treatment batch size for ongoing week was adjusted in accordance with the previous week cumulative injection.

The treatment is displaced down hole using the injector tubing string at very low rate (1 to 2 BPM). A low rate (10 gpm) duplex

positive displacement pump having a max. pressure rating of 400 psi. was sufficient in this case.

A total of 96 weekly treatments have been performed between December 1998 to December 2000. Total Microbial Products (concentrates) amounts 3892 gallons.

Water injected amount 189,000 M3, that means 1.65 times the Moveable Oil In Place existing in the pattern at MEOR start. The average rate of water injected was 256.4 M3/D in the same period, (Figure 40).

Monitoring

Fluid production monitoring was conducted using weekly conventional battery test for every producer affected to the pilot.

Serial oil samples are taken every month for changes in rheology and hydrocarbon compositional profiles. Ionic profile was monitored every week.

Instantaneous injection rate and cumulative water are continuously captured by a turbine flow meter inserted in the injection line.

Quality control of microbial products is based on CFU counts/ml. and by tracking biochemical profiles for every MEOR typology. The use of matricial miniaturized identification assays having more than 30 different dehydrated substrates producing a chromogenic indication permit to avoid any alteration or contamination in microbial products. Serial samples for every concentrate are taken periodically and prior to formulate the blend at well location. The results permit to maintain stable quality parameters during the microbial inoculation program.

Project evaluation

The evaluation covered technical and economical aspects. Multidisciplinary sessions were sustained every two months in average.

The evaluation program begun six month before pilot start date and was continued for 24 consecutive months. VC reservoir under PB-191 waterflooding and four active producer wells, were under weekly fluid monitoring and close production surveillance. A complete set of rheology parameters, specific geochemical fingerprints and biomarkers comparison was used to evaluate pre- and post-trial compositional alterations in produced fluids. To analyze MEOR performance Mann-Whitney (Non parametric test, also named U proof) statistic procedure was used to verify degree of significance between conventional waterflooding history (pre-MEOR) and post-MEOR evolutive data series. (Figures 19 to 20).

Technical aspects

Methodology to evaluate MEOR performance in waterflooding Schemes

MEOR's long-term distinctive response is to increase Oil Cut and simultaneously to reduce Water Cut (Figures 19, 20). This typical duality in MEOR response is explained by two

mechanisms working in combination and occurring in the colonized portion of the reservoir, the bioreactor: 1) Improved oil mobility from short-chain solvents originated by microbial alteration of heavy paraffinic ends. Rheology alteration of moveable oil in active streamtubes has a direct dependence with fractional flow via oil/water mobility ratio and 2) Further depletion of residual oil saturation by in-situ production of metabolites with low interfacial tension [Ref. 16, 17, 18 to 27].

Also, conformance efficiency improvements created by the colonizing biomass affecting the poral geometry in active streamtubes is another micro scale collateral mechanism to divert fluids to unflooded zones.

Project Performance is evaluated well by well by tracking Productivity Index (P.I.) evolution in correspondence with cumulative water injected. Individual well testing into common battery were used to have good data input for calculating and updating P.I. Four production tests per well per month, with confirmatory duplicate tests, were the usual monitoring practice to track project performance. Special care was taken to verify constancy in extractive conditions pre- and post-MEOR.

Pre-MEOR adequate baselines for every producer well and the pattern as a whole (Figure 19, 20) were calculated before starting the program of inoculations. Low noise (data scatter) allowing consistent decline curve determination is of the utmost importance for proper discrimination of microbial effects on well and reservoir productivity. Project predictive figures are obtained by using a proprietary 2D-vertically integrated multiphase reservoir simulator based on streamlines/streamtubes concepts. The simulator is coupled with fluid models that consider the oil as non-Newtonian, shear-rate-dependent fluid (Annex A) and geostatistic routines that could be easily adjusted to take into consideration small and big scale heterogeneities with minimal uncertainty.

It produces a set of MEOR Performance Curves (MPC) by each individual streamlines under analysis. The streamline approach permits to convert 2D transport cases of multiple species into one dimension problem along the streamline axial coordinate. It has incorporated the convective-diffusive equations and microbial kinetics to permit an easy input of rock-fluid-micro biota parameters, which are validated using field and lab data. [Ref. 28, 29, 30]

The use of MEOR performance curve methodology is accomplished in four basic steps:

- First, lab screening procedures are conducted to test rheology behavior and alteration in produced oils using control and inoculated samples for every well;
- Second, Incremental Oil Rates (IOR) and Water Cut vs. time figures are forecast using streamline simulators according to treatment design, produced and injected rates, reservoir description, pattern geometry and well connectivity information;

- Third, predicted curves are correlated with field performance data during pilot implementation; providing insights and guidelines for process optimization and treatment design alteration, permitting assessment of MEOR prospects and offering practical guidelines during field implementation and pilot project follow-up monitoring; and
- Fourth, economical models using field validated performance and alternative baseline forecasts are run to calculate a complete set of updated profitability indexes.

Tracers field test and Streamlines Simulations

Inter-well connectivity and allocation factors

Streamlines concepts are also useful to delimitate the poral space under flooding and to measure the injecting water reaching some specific producer. A complementary tracer field test using Tritium permitted validation of inter-well connectivity and allocation factors initially inferred and then matched by the use of different streamline simulation runs.

The tracer test in PB-191 pattern was initiated on December 15, 1999 using Tritium as radiotracer. The injected activity was 15 Ci (Curie), 555 GBq. PB-191 injects 256.4 m³/day.

The earlier and peaks Time Of Flights for tracer (TOF, in days from tracer pulse) in active producers is summarized below:

Producer	Earlier TOF	TOF at peak response
PB-83	72	153
PB-212	104	118 (first), 230 (second)
PB-220	90	230
PB-111	141	141 (first), 230 (second)

Figures 27 to 32 depicts tracer behavior. The match shown in Figure 30 used a composite of 19 streamlines near to interwell line. It is remarkable the low values of tracer activity recovered. The peak split in well PB-212 and PB-111 is explained by the segregation of petrophysic parameters in layers D2/C2 (without crossflow). The null response in PB-212 inferred by homogeneous case of streamlines pattern is explained by the "shielding effect" created by PB-83 and PB-220 drainage cones. Due to the fact that some tracer reach the PB-212 well, macro heterogeneities (15 degree north-east high permeability channel) in combination with the mentioned case can explain this particular tracer response, several runs with 3D-seismic detected faults validate this assumption.

The streamline based simulator permits that MEOR simulations and tracer analysis on typical waterflooding schemes can be achieved using laptop computers (256 MB RAM, 700 MHZ of clock frequency), taking 42 CPU hours to run 128x128x1 (16,384) grid cells for two layers having 100 streamlines per layer and partitioning every streamline in 60 timesteps. (Ref. 33, 34, 35, 36).

Pre- and Post- MEOR Fluid Production Series

Distinctive response in pre- and post-MEOR oil production series is the break in decline tendency. MEOR Improved oil decline rate is practically 0 (horizontal line in Figures 36, 37).

Four cases (named 1 to 4) summarized extrapolation of pattern MEOR performance (D_{MEOR} : 0 [1/day]) and MEOR decline tendency inflexion, in comparison with two decline hypothesis:

Case 1: D_{MEOR} : D_{conv} : **0.000375** [1/day]
MEOR commencement decline from pilot start, jlim: **2** [years], Figure 36.

Case 2: D_{MEOR} : D_{conv} : **0.000375** [1/day]
MEOR commencement decline from pilot start, jlim: **4** [years]

Case 3: D_{MEOR} : D_{conv} : **0.000590** [1/day]
MEOR commencement decline from pilot start, jlim: **2** [years], Figure 37

Case 4: D_{MEOR} : D_{conv} : **0.000590** [1/day]
MEOR commencement decline from pilot start, jlim: **4** [years]

MEOR to Conventional Decline improvements reach 14.3 to 33.9 according with baseline hypothesis. (Figure 36, 37; Table 09).

Oil cut increment

Evaluation of incremental oil cut was performed using a total of 16 four-point post-MEOR production data averages and compared with pre-MEOR series and forecasted baseline, a gain of 2.2% is shown on next figure. This baseline was based on the composite response of selected group of streamlines on a well-by-well basis. The predictions were crosschecked by parametric models under phase-segregated hypothesis (Dake model) and by the use of 1-D two layers integrated streamline simulations. In both cases was considered the oil as non-Newtonian (two-parameter Ostwald de Waele Nutting scheme).

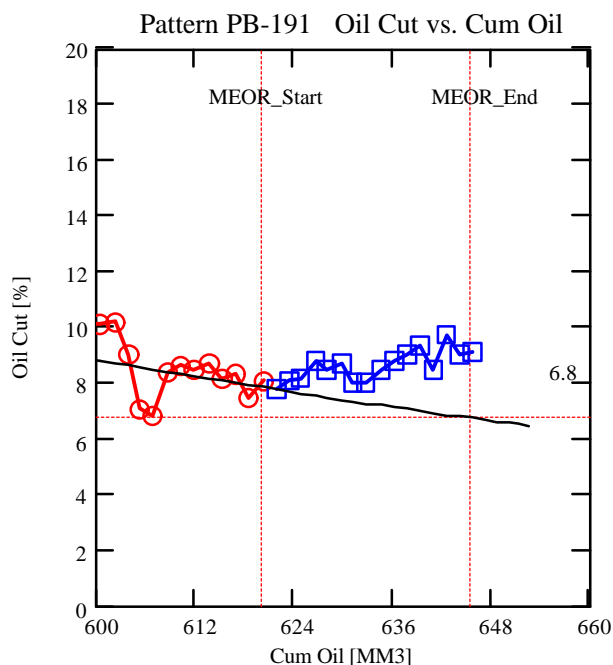
The influence on MEOR response of petrophysic parameters is mainly associated with two aspects:

1) Microbial Migration Rates (MMR) related to reservoir poral geometry (pore throats distributions), co-current velocity field and microbial motility; and

2) Shear Rate Field (SRF) 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. This point will be depends on transverse distances (perpendicular to streamline axial coordinate) 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 degree of compositional alteration to activated unmoveable oil. Next figures summarize pre- and post-MEOR oil and water cut comparative history. For the sake of brevity

composite performance graphs was preferred on this article. Change in oil decline tendency before and after MEOR is clear and well defined. At the end of evaluation period the Incremental Oil averages 14.3% and 33.9 % over case 1 and case 3 baseline alternatives respectively (Table 9).



Pre- and Post_MEOR oil cut evolution: At the end of pilot evaluation period the gain in oil cut is 2.2%.

Recovery Factors

At the end of the two-year MEOR program, it is inferred a range from 3.3 to 9.2% as Incremental Recovery Factor based on Moveable Oil In Place (MOIP) at MEOR commencement date. The calculation of MOIP value is critic to compare improvements with different Enhanced Oil Recovery processes in comparison with previous stages of conventional waterflooding (Annex D; Tables 6, 7, 8 and 9; Figures 23, 24, 25 and 26).

The method to estimate the floodable poral volume needs to be approached by a combination of static (geostatistic) and dynamic (potential flow) models.

MEOR results need to be correlated in correspondence with some adequate measure of the moveable fluids content in the poral space under waterflooding influence. The value need to be calculated at MEOR start for further reference.

The RF measures the change of oil saturations in a given poral volume and during a specific time interval.

The following considerations to calculate RF during MEOR programs are pertinent:

The number of volumetric cells (Ncells) involved in the summation needs to be stable during the period of analysis and pertain only to the Active Poral Volume (APV) affected by the waterflooding process in the selected pattern. To calculate the APV it is convenient to define the areal extension affected by water using streamline envelopes (Figures 23, 24) and then to produce the cell by cell vertical integration. During this process, net interval values (layer thickness) and petrophysic parameters are interpolated using geostatistical methods over every active layer. It is also convenient to validate all assumptions with the subjacent geology model and tracer response (Figure 23, 24).

MEOR performance need to be measured in connection with some maturity measure of the conventional water flooding at the moment to initiate MEOR. To evaluate maturity it is necessary to rebuild the fractional flow vs. water saturation history of the injection pattern. This was accomplished by using an adaptation of Dake method [Figure 19, 20, 21, 22; Ref. 39, 44]. After that, a reasonable inference of the status of moveable fluid saturations at project start can be derived and used as input for simulations (Table 7).

The present global efficiency in terms of water injected per oil produced for active waterflooding projects in La Ventana block is included as an additional maturity reference.

This efficiency figure is a dimensionless index expressed in terms of water injected per volume of oil produced (M3/M3) for every reservoir compared with similar figure in PB-191 pattern is as follow:

M3 of water injected per M3 of oil produced (present time)

Reservoir:

TRC:	19.4
BRC:	24.4
LRB:	3.0
<u>VC:</u>	<u>12.1</u>

The calculation of this efficiency parameter in PB-191 pattern results in 5.6_(M3/M3), this last is not agreeing with VC global values (12.1) and could be suffering the influenced of primary production becoming from PB-212 and PB-220 (perforated at 1995 and 1997 respectively)

Different evaluation scenarios were discussed in terms of size of flowable area, petrophysic models for layers D2, C2; and fluid saturations at MEOR commencement date. Table 9, summarized the results for cases 1 and 3.

The Incremental Oil produced during the two year MEOR program (Tables 10 to 14), varies from 4.81 to 9.75 M3 (30.2 to 61.3 barrels). These values are referred to the Total Volume of Microbial product used (3892 gallons) during equal period and it produces a global parameter of Microbial Product Efficiency (MPE). In La Ventana Project, MPE ranges from 7.8 to 15.7 barrel per gallon.

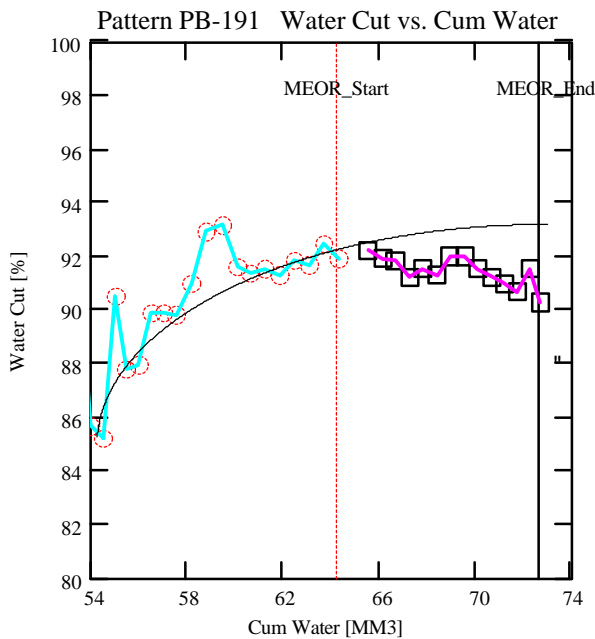
During the two year program the injected water amounts 189,000 M3, that means 1.65 times the Moveable Oil in Place

existing in the pattern at MEOR start (using the same reference this number totals 8.13 times for the conventional waterflooding history, 1989-1998). The average rate of water injected was 256.4 M3/D in the same period.

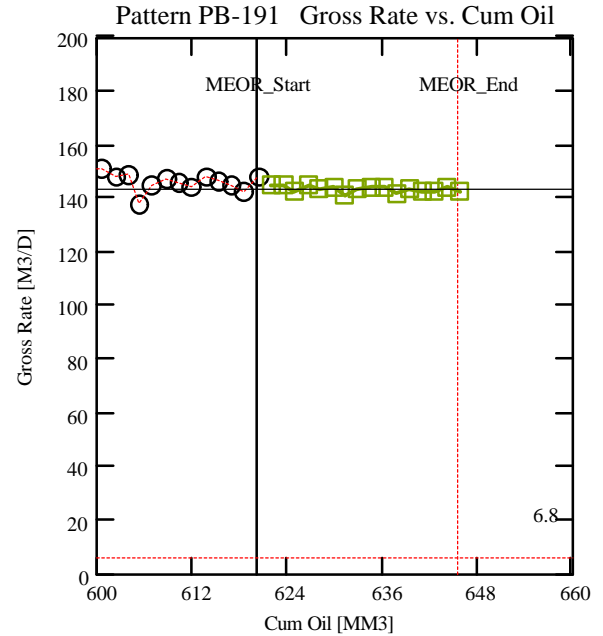
MEOR to Conventional Decline improvements reach 14.3 to 33.9 according with baseline hypothesis. (Table 09).

Water Cut Reduction

Next Figures summarizes pre- and post-MEOR water cut and gross rate evolution vs. cumulative values. Water cut tendencies for the four-well composite is shown below. Water influx is decreasing in relation with oil. Change in water cut tendency is evident and is a clear indication of mobility alteration at reservoir conditions. The result is a 2% reduction at MEOR end. Gross rate remain stable.



Pre- and Post-MEOR water cut evolution



Pre- and Post-MEOR gross rate stability.

Rheological comparison

A clear improvement in oil rheology was detected at MEOR program termination. The treated oils are compared with control oil from PB-109. The shift in Viscosity vs. Temperature curves is remarkable (Figures 12 and 13).

Geochemical comparison

In a general manner, the oils appear to have experienced very slight compositional and molecular changes with respect to the untreated counterparts. In addition, the four MEOR treated samples look very similar among them. Many of the variations detected are about the same range assessed between the reference PB-109 and PB-116 oils. Slight variations that could potentially have originated in the treatment are:

Composition, the treated samples are slightly poorer in saturated hydrocarbons.

Whole oil gas chromatography, PB-83 oil developed an n-alkane distribution significantly different from the three other treated samples and from control sample PB-109, augmenting the proportion of light and mid molecular weight compounds with respect to heavy ones (next column figure).

C7 GC, no major or systematic change is visualized, for exception of the somewhat richest proportion of C6 and C7 compounds measured for PB-83 oil with respect to the other three treated samples. However, the data represent about the same proportion or even lower than that measured for PB-109 and PB-116 oils.

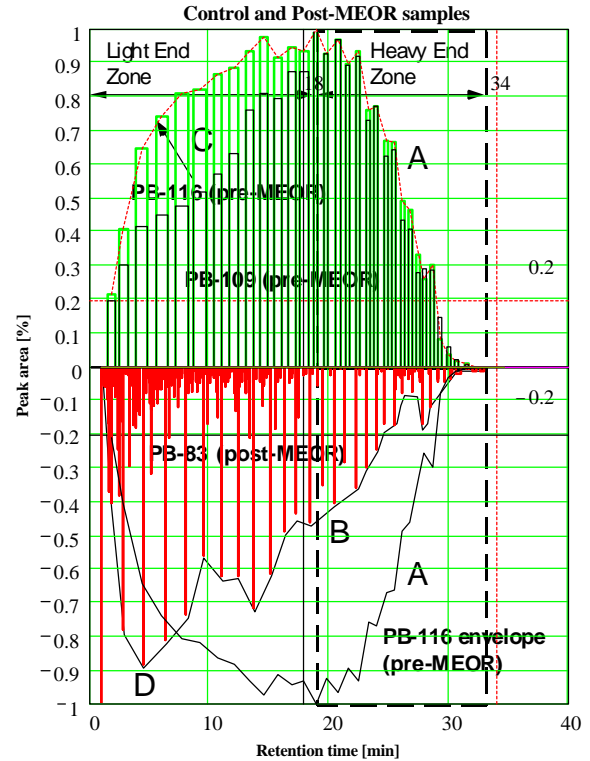
Aromatics GC-MS analysis, treated samples have phenanthrene/dibenzothiophene ratios in the range 4.8-5.7; those of untreated samples are 9.8-11.9. These variations could apparently derive from the MEOR process. Additionally, C28 TA sterane (20R) in the m/z 231 mass fragmentogram is slightly augmented with respect to the other components. This could be due to compositional variations of the oils in the area (differential charge, facies, etc.)

Saturate GC-MS, the overall absolute concentration of biomarkers (ppm) in treated samples is slightly to moderately augmented with respect to untreated samples. However, it seems difficult to explain this only through the MEOR process. Consistently with the C28 TAS increase, saturate steranes have the C29 component slightly augmented with respect to C27 and C28, in the treated samples. Again the effect could be attributed to variability of the oil in itself.

Aromatic hydrocarbons have general and non-systematic variations with respect to the untreated samples. The trend involving changes in the proportions of naphthalenes and phenanthrenes detected in other study (Piedras Coloradas, Ref. 4) is not evident in this set (Figure 7, 8).

High temperature gas chromatography keeps the same envelope obtained for the treated samples and no significant change can be mentioned.

The figure on next column is illustrative and summarizes the changes in La Ventana MEOR application. It shows control compositional envelopes (upper sector, traces A and C) for control oils (PB-109 and PB-116 respectively) and similar profile for oil sampled from PB-83 wellhead (lower part, trace B). Light ends (D) are mainly originated by enzymatic cracking on heavy ends of n-alkanes (A, coincident in both controls) and in less degree by alteration of zone C (microbial alteration of saturate hydrocarbon is selective with carbon chain length). The shift of line B to the left means a lower molecular composition that in A (compare with Figure 12 and 13 and Table 2). This behavior is coherent with 9% (residence time: 336 hs.) of microbial generated solvents (equivalent to mix C12-C14 segment of external solvents in the oil) during lab testing of microbial inoculated oils (Figure 11).



Comparative Compositional Changes Between Microbial-altered and Control Oils

°API variation (at lab normalized conditions)

Pre-MEOR (Control based on PB-109/PB-116): 29.1/25.9

Post-MEOR	°API value	Variation with Controls
PB-83	30.3	+1.2/+4.4
PB-212	19.4	-9.7/-6.5
PB-220	21.4	-7.7/-4.5
PB-111	30.8	+1.7/+4.9

Economical aspects

Short-term and five year forecasts using net present value curves based on pattern performance curves were calculated at project termination. Then an integrate set of NPV (net Present Value) and CIB (Cost per Incremental Barrel) figures for four different cases of MEOR and conventional decline extrapolation was calculated over a similar period with sensitivity and risk analysis. Different economic indexes like Pay-Out (break-even point analysis), Exposure, and Internal Rates of Return (I.R.R.) were derived. Further analysis with floating scenarios of oil prices (from location-adjusted WTI of 20 to 15 \$/barrel), taxes and treatment alternatives (50 to 100 p.p.m.) provide a detailed profitability evaluation (Tables 10, 11, 12 and 13).

Pay-Outs (PO)

Based on a well-by-well analysis a range of PO values from 159 to 545 days from pilot start was obtained (Table 14)

Cost per Incremental Barrel (CIB)

CIB was varying from 2.98 to 6.05 \$/barrel during the two-year pilot stage. On MEOR Expanded scales, CIB is forecast to decrease to below 1.39 to 2.35 \$/barrel. The difference is due to pilot trials being conducted at small scale, and being intensive in studies, operative support and engineering. Also the two year period is suffering a time delay equivalent at least of 0.8 PVI to begin to develop MEOR response.

Incremental Reserves (IR)

According with the minimal and maximal decline hypothesis IR totalizes an range of values of 1255 to 3339 M³ of oil during the first year and 3555 to 6419 M³ of oil during the second year. The economic limits (<2 M³/D per well) are not presumed to be reached before next 8 years. A range of values of IR from 22,002 to 40,800 M³ for the first five years of MEOR application was assumed as conservative. Values were considering well-by-well analysis and the further integration of individual calculations for the composite for the four different decline cases.

Internal Rate of Return (IRR)

Actual IRR value are far above of original inferences (54 and 159%) and having better values for the average optimized prospect.

Biosafety issues

MEOR bacteria used in La Ventana project are non-pathogenic. During the pilot, special care was taken to meet local and foreign regulation in regard to environmental and health topics

Toxicity tests on animals and plants were done by the Institute of Microbiology (Academia Sinica) and by the Institute of Atom Energy Utilization, Chinese Academy of Agriculture Science, both in the Peoples Republic of China. Selected animals and plants were Kunming mice (200 individuals, weighting 18-20 grams., half-male, half-female) and Cucumber (Jinyan #5 strain) and rice (Yuefu strain) seeds respectively. Special essay protocols and method of exposure using microbial products number #1, #4, #5 and #6 were applied to germinated plants, seeds and animals under test.

All results were no adverse affects for plants or animals. The microbial product caused no abnormalities in plants (rice and cucumber) and mice. No abnormality or disease occurred on different crops by different ways of treatment. No abnormality occurred of heart, liver, spleen, lung, kidney or intestine of test mice.

Conclusions

1- Biotechnological methods on injection schemes has an interesting prospect on these fields if proper screening is conducted for candidates patterns.

- 2- During the pilot, MEOR Incremental Reserves (IR) totalizes a range of 1,255 (7893 bbls.) to 3,339 (21,000 bbls.) M³ of oil during the first year and 3,555 (22,358 bbls.) to 6,419 (40,371 bbls.) M³ during the second year. Values ranging from 22,002 (138 Mbbls.) to 40,800 (256 Mbbls.) M³ of oil for the first five years of MEOR continuation was assumed as a conservative projection.
- 3- According with present oil prices scenarios and treatment costs, MEOR is profitable at pilot and scaled stages. On Expanded scale, Cost per Incremental Barrel (CIB) is forecast to decrease to below 1.39 to 2.35 \$/barrel.
- 4- Multidisciplinary team integration and proper monitoring techniques are key factors to optimize fractional flow and incremental recovery in microbial stimulated reservoirs.
- 5- Streamline simulators constitutes a useful tool to evaluate Recovery Factors during MEOR evaluation and constitutes an important help with project design tasks.
- 6- In case of MEOR project scalation a biotechnology approach to substitute chemical biocides to displace Sulphate Reducing Bacteria (SRB) will be necessary.

Course of future actions

- 1- To conclude in-course optimization stage in PB-191 injection pattern.
- 2- To evaluate best expansion strategies for C2-D2 reservoirs to maximize economic return.
- 3- To evaluate MEOR prospects in another reservoirs of LA Ventana Block under waterflooding influence.

SI metric Conversion Factors

acre-foot x	1.233 489	E+03 = m ³
barrel x	1.589 873	E-01 = m ³
foot x	3.048*	E-01 = m
md x	9.869 233	E-04 = μm ²
ml x	1.0	E-06 = m ³
psi x	6.894 757	E+00 = kPa
Bq x	3,7	E+10 = curie
Bq x	1	E+00 = d/sec

where:

$$d/sec : 1 \text{ disintegration per second}$$

$$\text{U.S.Gal x } 3.785 \text{ 412 E+00} = \text{L}$$

$$^{\circ}\text{F } (^{\circ}\text{F} - 32) * 5/9 \text{ E-01} = ^{\circ}\text{C}$$

* Conversion factor is exact

Acknowledgements

We want to thank to ASTRA-REPSOL Company and Microbes Inc. for permission to publish this paper. Special thanks to La Ventana directive staff and operative team for valuable discussion to interpret MEOR field data.

References

1. Microbial EOR Technology Advancement: Case Studies of Successful Projects. F.L. Dietrich, SPE, F.G. Brown, SPE, Z.H.Zhou, SPE, Microbes, Inc.; and M.A.Maure, SPE, Green Consultores. SPE 36746.
2. Systematic Extensive Laboratory Studies of Microbial EOR Mechanisms and Microbial EOR Application Results in Changqing Oilfield. Dejun Deng, Chenglong Li, Quanyi Ju, Pingcang Wu, Changqing Petroleum Administration Bureau and F.L. Dietrich. Microbes Inc. SPE 54380.
3. Microbial EOR Laboratory Studies and Application Results in Daqing Oilfield. Yijiang Zhang, Zhengshun Xu, Ping Ji, and Weihong Hou, Daqing Petroleum Administration Bureau and Forrest Dietrich, Microbes Inc.. SPE 54332.
4. Microbial Enhanced Oil Recovery Pilot Test in Piedras Coloradas Field, Argentina. M.A. Maure, SPE, and F.L. Dietrich, SPE, Microbes Inc. and V.A. Diaz and H. Argañaraz, Perez Companc S.A. SPE 53715.
5. MEOR – Altamont/Bluebell Field Project. L.P. Streed, Coastal Oil & Gas Corp., and F.G. Brown, National Parakleen Co. SPE 24334.
6. Microbes: The practical and Environmental Safe Solution to Production Problems, Enhanced Production, and Enhanced Oil Recovery. F.G. Brown, National Parakleen Co. Inc. SPE 23955.
7. Microbial-Enhanced Waterflooding : Mink United Project. Rebecca S. Bryant, SPE, and Thomas E. Burchfield, SPE, Natl. Inst. for Petroleum & Energy Research ; DM. Dennis, Microbial System Corp. ; and D.O. Hitzman, Injectech Inc. SPE 17341.
8. Geochemical Report, Source Rock Evaluation of the PCXP 1002 Well and Characterization of Five Oils, Piedras Coloradas Field, Cuyo Basin, Argentina, October 1988, Exlog Consulting Services.
9. Laboratory Testing of a Microbial Enhanced Oil Recovery Process Under Anaerobic Conditions. Bruce Rouse, Franz Hiebert, and L.W. Lake, U. of Texas. SPE 24819.
10. New Tools Target Oil-Quality Sweet Spots in Viscous-Oil Accumulations. P.C. Smalley, SPE, and N.S Goodwin, BP Exploration ; J.F. Dillon and C.R. Bidinger, BP Exploration (Alaska) Inc. ; and R.J. Drozd, IITRI. SPE 36652.
11. Crude Oils in Reservoirs : The Factors Influencing their Composition. Chapter I. 6. Ph. Blanc and Connan. (Elf Aquitaine, Centre Scientifique et Technique Jean Feger 64018 Pau Cedex, France.)
12. Pieter Shenck Award acceptance speech Geochemical indicators of biodegradation : tools for developing and managing heavy oil assets (17th. International Meeting on Organic Geochemistry, Donostia- San Sebastian, September 6, 1995). Mark A. McCaffrey.
13. Calculating Viscosities of Reservoir Fluids From Their Compositions. John Lohrenz, Bruce G. Bray, Members AIME, Charles R. Clark. Continental Oil Co, Ponca City , Okla. U. of Kansas. Lawrence , Kans. Paper presented at SPE Annual Fall Meeting, held in Houston, Tex., Oct. 11-14-1964.
14. Wettability Literature Survey - Part 2 :Wettability Measurement. William G. Anderson, SPE, Conoco Inc. Journal of Petroleum Technology, November 1986.
15. Surfactant - Base EOR Mediated by Naturally Occurring Microorganisms. CP. Thomas, SPE, M.L. Duvall, SPE, E.P. Robertson, SPE, K.B. Barrett and G.A. Bala, SPE, EG&G Idaho Inc.. SPE 22844.
16. Adsorption of Carboxylic Acids on Reservoir Minerals From Organic and Aqueous Phase. Lene Madsen, SPE, and IDA Lind, SPE, Technical U of Denmark.
17. Chemistry of the Crude Oil/Brine Interface. Hill S. Buckley, New Mexico Petroleum Recovery Research Center, New Mexico Institute of Mining and Technology. Proceeding of the 3rd International Symposium on Evaluation of Reservoir Wettability and its Effect on Oil Recovery. Laramie, WY, 21-23 September 1994.
18. Dependence of Pseudomonas aeruginosa continuous culture biosurfactant production on nutritional and environmental factors. Luis H. Guerra-Santos, Othmar Käppeli, and Armin Fietcher. Departament of Biotechnology, Swiss Federal Institute of Technology, Hönggerberg, 8093 Zürich, Switzerland.
19. Production of Biosurfactants by a Mixed Bacteria Population Grown in Continuous Culture on Crude Oil. Georges Mattei and Jean-Claude Bertrand. Centre d'Océanologie de Marseille (URA 41), Faculté des Sciences de Luminy, 13288 Marseille Cedex 9.
20. Effect of addition of Pseudomonas aeruginosa UG2 inocula or biosurfactants on biodegradation of selected hydrocarbons in soil. Devender J. Jain, Hung Lee and Jack T. Trevors. Journal of Industrial Microbiology, 10 (1992) 87-93, Published by Elsevier.
21. Effect of the Carbon Source on Biosurfactant Production by Pseudomonas Aeruginosa 44T1. M. Robert, M. E. Mercadé. M. P. Bosch, J. L. Parra, M. J. Espuny, M. A. Manresa, J. Guinea. Biotechnology Letters Vol 11 No 12. 871-874 (1989).
22. Pseudomona Aeruginosa Biosurfactant Production in Continuous Culture with Glucose as Carbon Source. Luis H. Guerra-Santos, Othmar Käppeli, and Armin Fietcher. Department of Biotechnology, Swiss Federal Institute of Technology, Hönggerberg, 8093 Zürich, Switzerland. Applied and Environmental Microbiology, Aug 1984.
23. Enhanced Production on Surfactin from Bacillus subtilis by Continuous Product Removal and Metal Cation Additions. D. G. Cooper, C. R. Macdonald, S. J. B. Duff, and N. Kosarig. Biochemical Engineering Faculty of Engineering Science. The University of Western Ontario. Applied and Environmental Microbiology, Sept 1981.
24. Production of extra cellular emulsifying agent by Pseudomona aeruginosa UG1. Cynthia G. MacElwee, Hung Ledd, and Jack T. Trevors. Department of Environmental Biology, University on Guelph. Journal of Industrial Microbiology. 5 (1990) 25-32.
25. Biosurfactant production by two isolates Pseudomonas Aeruginosa. C. Rocha, F. San-Blas, G. San-Blas and L. Vierma. World Journal of Microbiology and Biotechnology, 8 , 125-128.

26. The production of Biopolymers for Enhanced Oil Recovery Use. Ian W. Sutherland. Pages 200-204 Microbes and Oil Recovery. Volume I, International Bioresources Journal J.E. Zajic. E.C. Donaldson.
27. Isolation and Characterization of Halotolerant, Thermophilic, Anaerobic, Biopolymer-Producing and Biosurfactant-Producing Bacteria. S.M. Pfiffner, G.E. Jenneman, G.B. Walker Jr. M. Javaheri, M.J. McInerney, and R.M. Knapp. Pages 285-294. Microbes and Oil Recovery. Volume I, International Bioresources Journal J.E. Zajic. E.C. Donaldson.
28. A Mathematical Model for Microbially Enhanced Oil Recovery Process. Xu Zhan, R.M. Knapp, and M.J. McInerney, U. of Oklahoma. SPE/DOE 24202.
29. Mathematical Modeling of Microbial Enhanced Oil Recovery. M. R. Islam, U. of Alaska-Fairbanks. SPE 20480.
30. The Transport of Bacteria in Porous Media and its Significance in Microbial Enhanced Oil Recovery. Long Kuan Jang, M.M. Sharma, and T.F. Yen, U of Southern California. SPE 12770.
31. A Streamline-Based 3D Field-Scale Compositional Reservoir Simulator. Marco R. Thiele, SPE, Rod P. Batycky, SPE, and Martin J. Blunt, SPE Stanford University. SPE 38889.
32. Mathematical Modeling of Microbial Enhanced Oil Recovery. M.R. Islam, U. Of Alaska-Fairbanks. SPE 20480.
33. Simulating Flow in Heterogeneous Systems Using Streamtubes and Streamlines. M.R. Thiele, SPE, R.P. Batycky, SPE, and M.J. Blunt, SPE, and F.M. Orr Jr, SPE, Stanford U.. SPE Reservoir Engineering, February 1996.
34. Semi analytical Computation of Path Lines for Finite-Difference Models. David W. Pollock. Ground Water, Vol. 26 N° 6
35. Experimental Study of Waterflood Tracers. Robert A. Greenkorn, Jersey Production research co. Tulsa, Okla. January 1962. SPE 169.
36. Aqueous Tracers for Oilfield Applications. R.D. Hutchins and H.T. Dovan, Unocal Science & Technology, and B. B. Sandiford, Polymer Applications. SPE 21049.
37. Effect of Wettability Alteration on Water/Oil Relative Permeability, Dispersion, and Flowable Saturation in Porous Media. F.H.L. Wang, SPE, Exxon Production Research Co. SPE Reservoir Engineering, May 1988.
38. A Genome Probe Survey of the Microbial community in Oil Fields. Voordouw. G. ; Telan , A. J. Department of Biological Sciences, The University of Calgary, Alberta, T2N 1N4, Canada.
39. A Prediction Technique for Immiscible Processes Using Field Performance Data. Iraj Ershaghi, SPE, U. of Southern California. Dobby Abdassah, SPE, U. of Southern California. SPE 6977.
40. A Study of Formation Plugging with Bacteria. J.T. Raleigh. D.L. Flock. Members AIME . The U. of Alberta. Edmonton, Alta. Journal of Petroleum Technology, July 14, 1964.
41. Microbes Deep inside the Earth. James K. Fredrickson and Tullis C. Onstott. Scientific American, October 1996.
42. Advances in the characterization of microbial populations in the subsurface. Ian Head. NRC News, May 1996, Subsurface Microbial Populations.
43. Modeling and Laboratory Investigation of Microbial Transport Phenomena in Porous Media. M-M. Chang, F.T-H. Chung, R.S. Bryant, H.W. Gao, and T.E. Burchfield. IITRI/NIPER. SPE 22845.
44. The Practice of Reservoir Engineering. Laurie P. Dake. Development in Petroleum Science, 36. Pages 441 to 445 1994 Edition, Elsevier Science B. V.

Figures

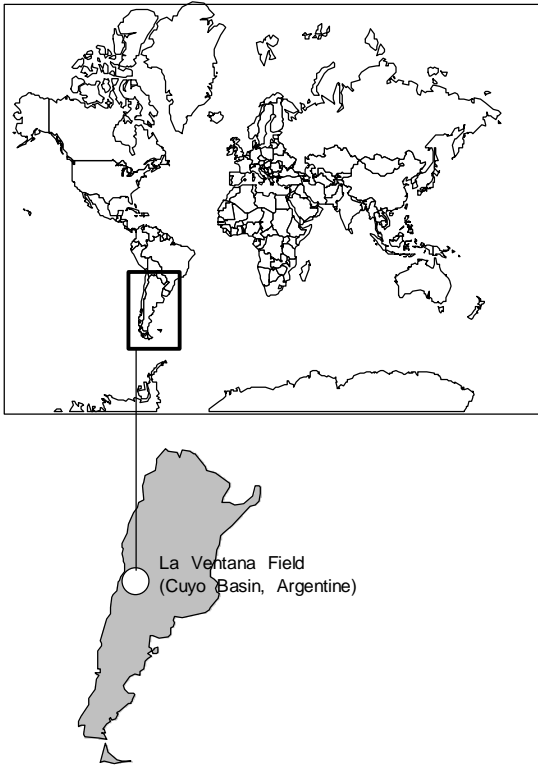


Figure 1: Field Location

Formation Name

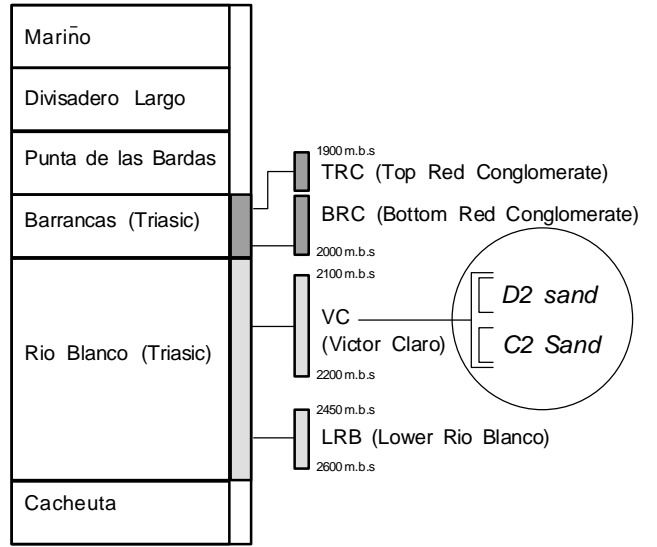


Figure 2: Target Reservoirs and Objective Sands

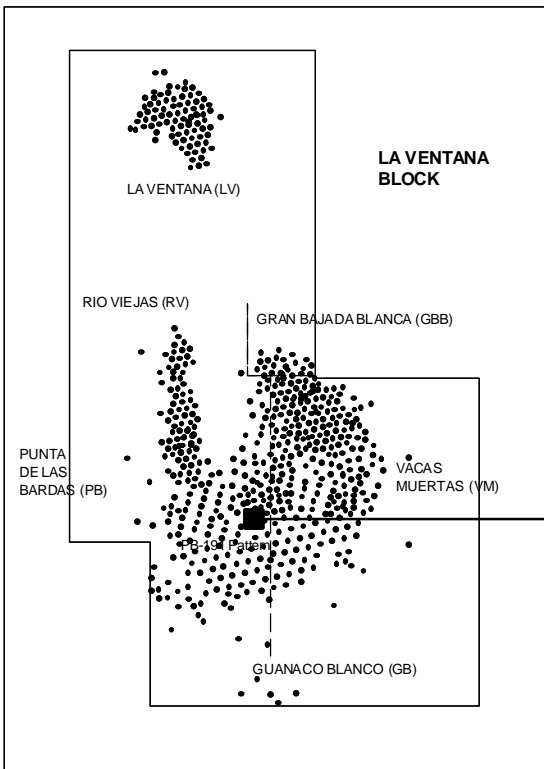


Figure 3: Pattern of PB-191 injector, Relative Situation Of Active Wells Reaching D2 Sand

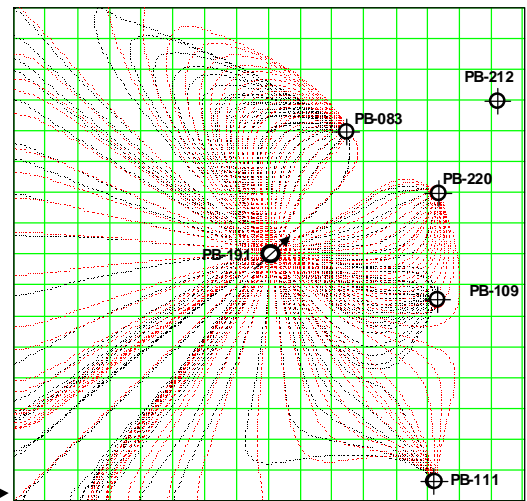


Figure 4: Streamlines and Well Locations in PB-191 Pattern

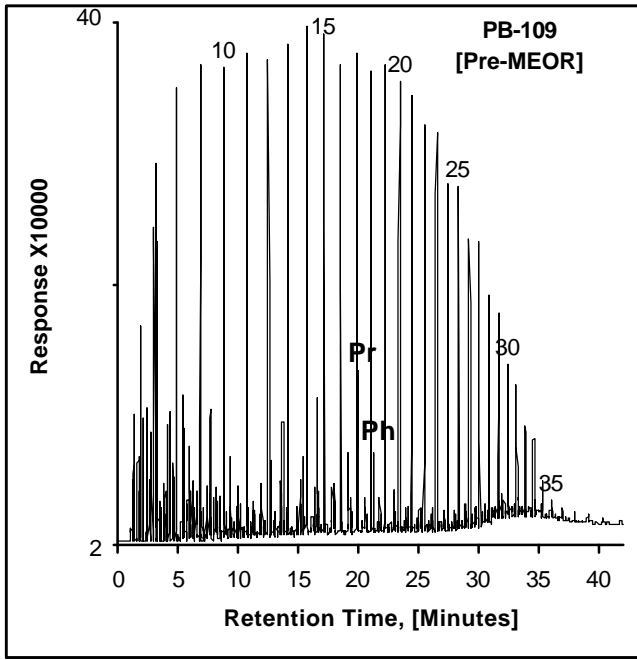


Figure 5: Chromatographic Profile in Control Oil

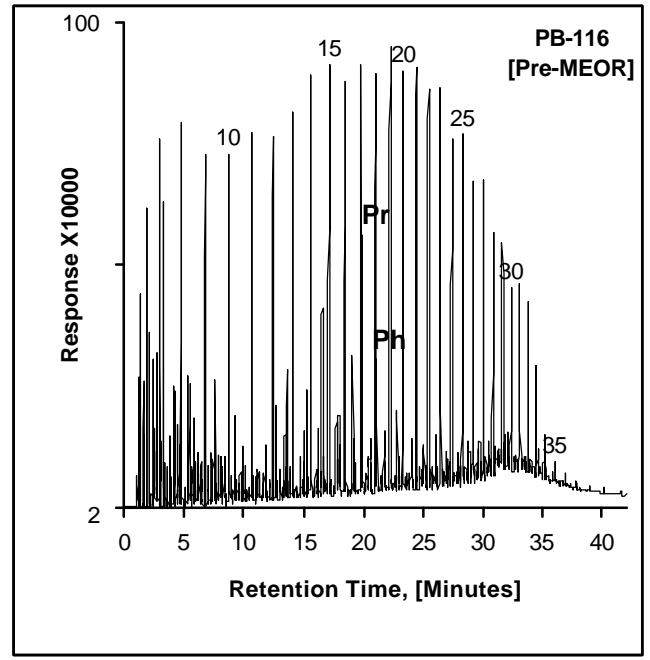


Figure 6: Chromatographic Profile in Control Oil

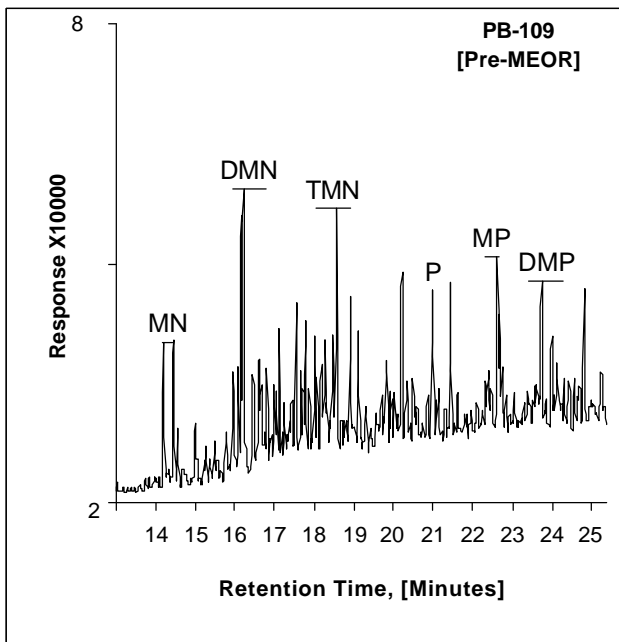


Figure 7: Aromatic Hydrocarbons Distributions in Control Oil

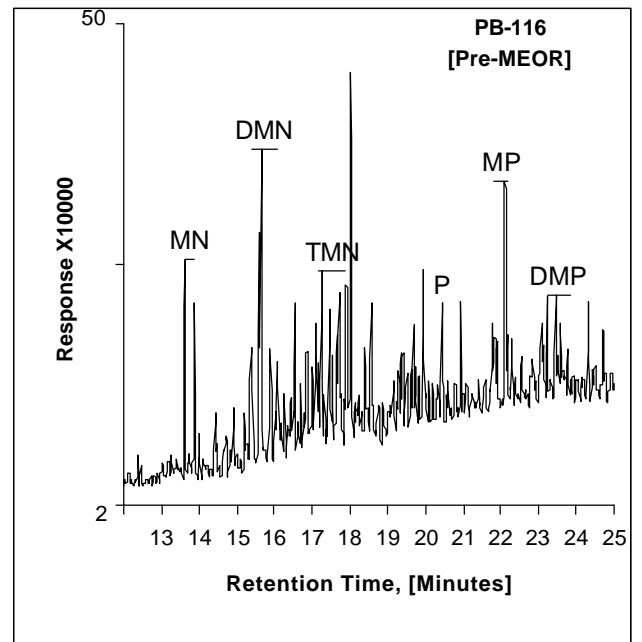


Figure 8: Aromatic Hydrocarbons Distributions in Control Oil

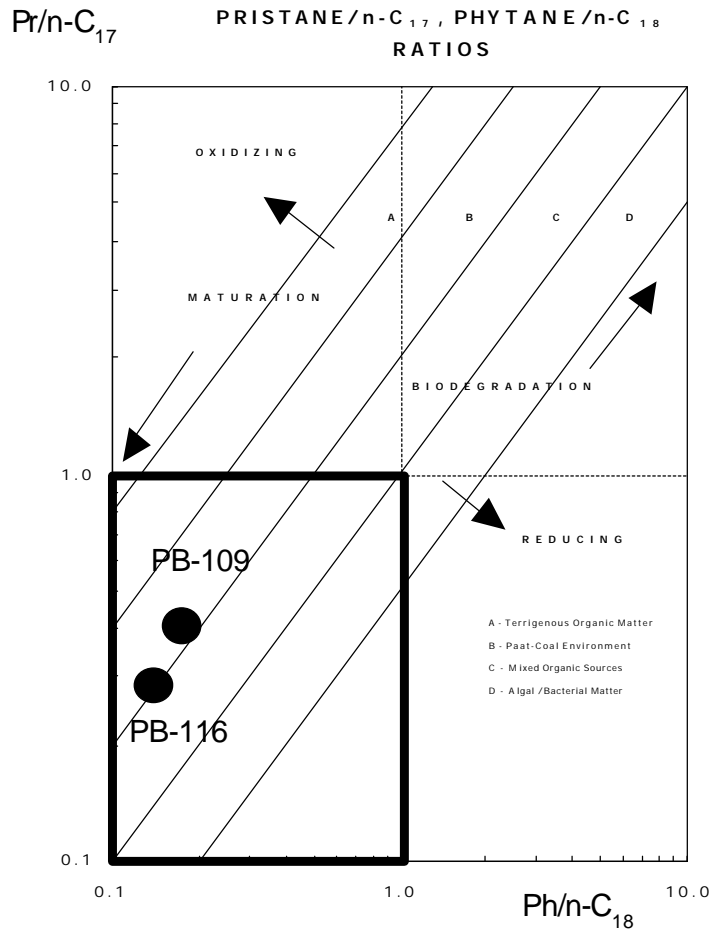


Figure 9: Pre-MEOR Biodegradation Status in Control Oils

Liquid Chromatography					
	Status	Saturates (%)	Aromatics (%)	NSO (%)	Asphaltenes (%)
PB-109	Pre-MEOR	64.3	11.7	4.8	19.1
PB-116	Pre-MEOR	60.6	20.3	15.0	4.1

Table 1: Main Component Participation in Control Oils

THOMPSON Compositional Ratios						
Well Samples	Heptane Value	Paraffinicity	Aromaticity (1)	Isoheptane Value	Aromaticity (2)	Paraffin Branching
	(H)	(F)	(B)	(I)	(A)	(R)
PRE-MEOR samples						
PB-109	31.15	1.19	0.14	0.56	0.04	7.39
PB-116	29.41	1.25	0.14	0.48	0.05	7.13
POST-MEOR samples						
PB-111	27.65	1.15	0.16	0.51	0.05	7.69
PB-220	27.74	1.13	0.17	0.53	0.04	7.82
PB-212	28.52	1.12	0.17	0.52	0.04	7.84
PB-83	28.30	1.12	0.17	0.52	0.05	7.88

Table 2: Status of Alteration Parameters in Control Oils and post-MEOR samples

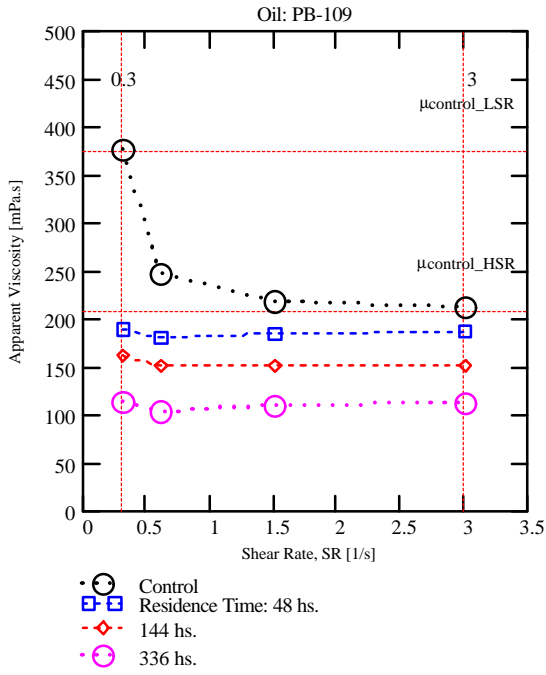


Figure 10: Rheological Profile for Control and Lab Inoculated Oils

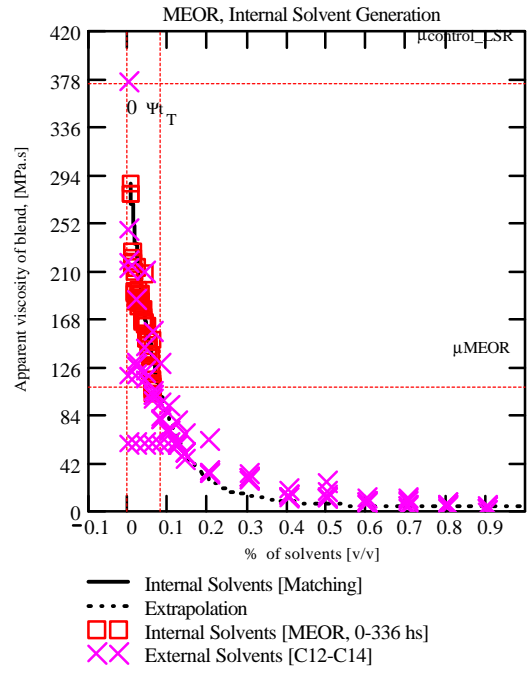
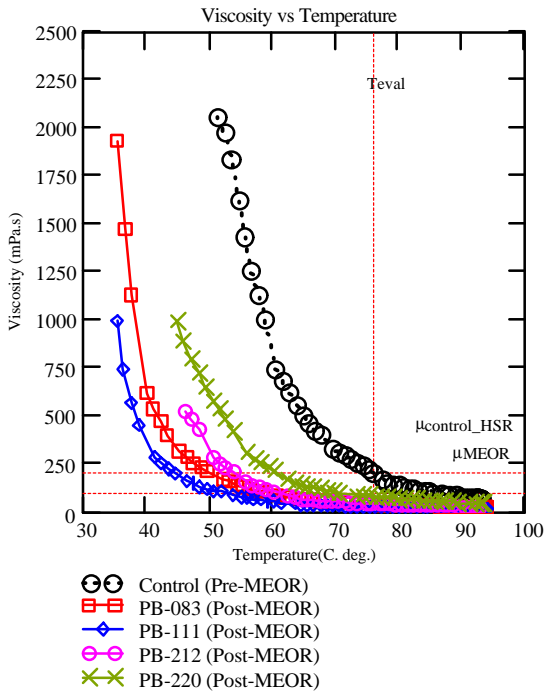
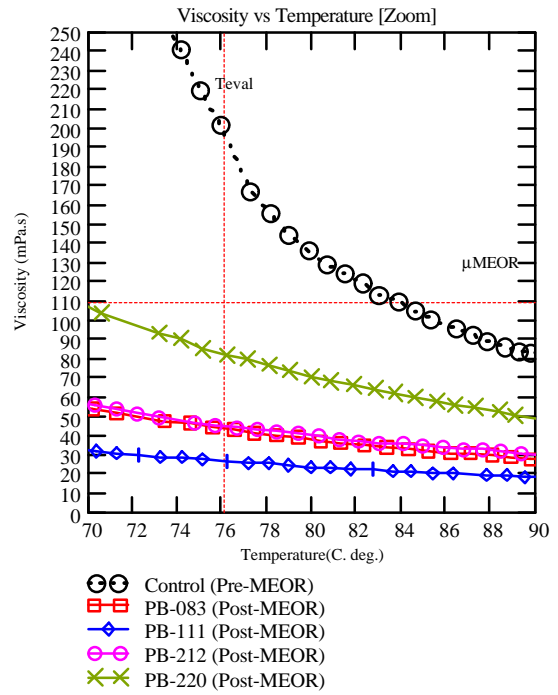


Figure 11: Internal (Microbial Induced) and External Solvent Comparison



Figures 12: Post-MEOR Comparison with Control Oil



Figures 13: Zoom of High Temperature Zone

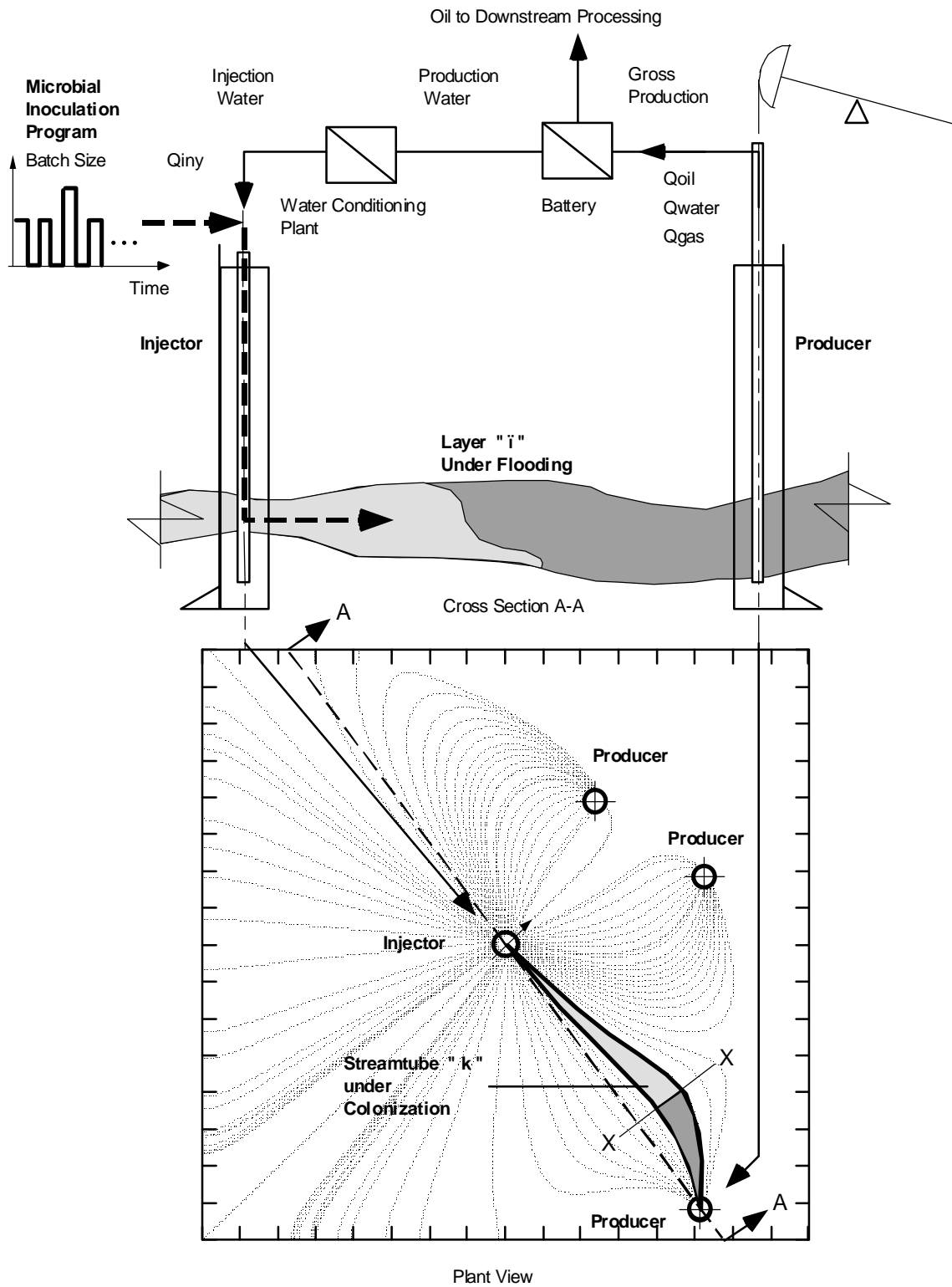
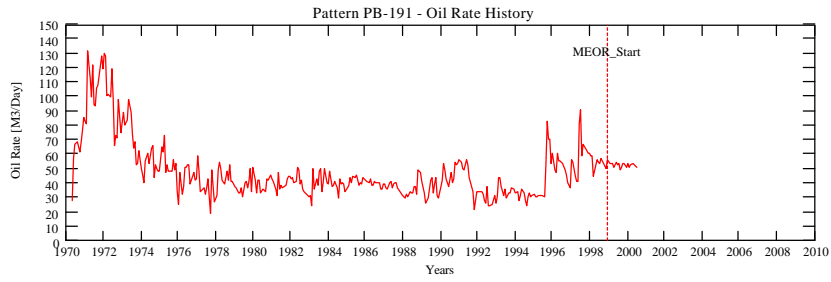


Figure 14: Streamtube Colonization in Target Sand by Inoculating Injection Water, Conceptual Frame



Figures 15: Oil Rate History

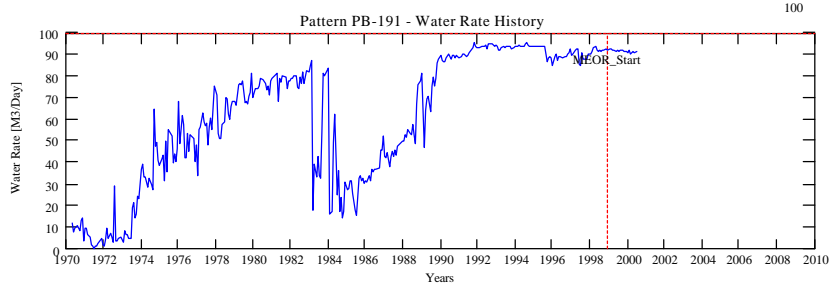


Figure 16: Water Rate History

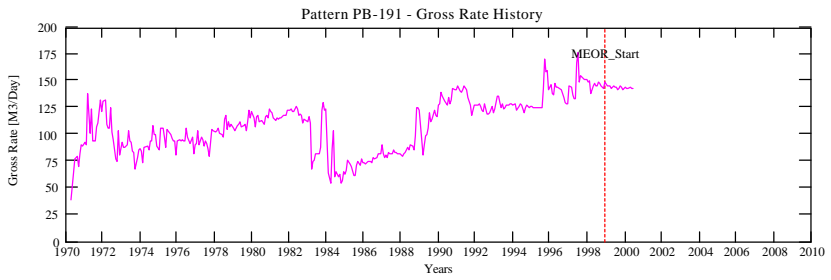


Figure 17: Gross Rate History

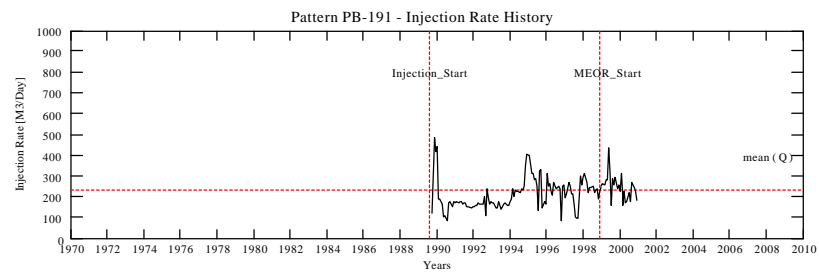


Figure 18: Injection Rate History (PB-191 Operates as Injector of VC (D2-C2) Since August 1989)

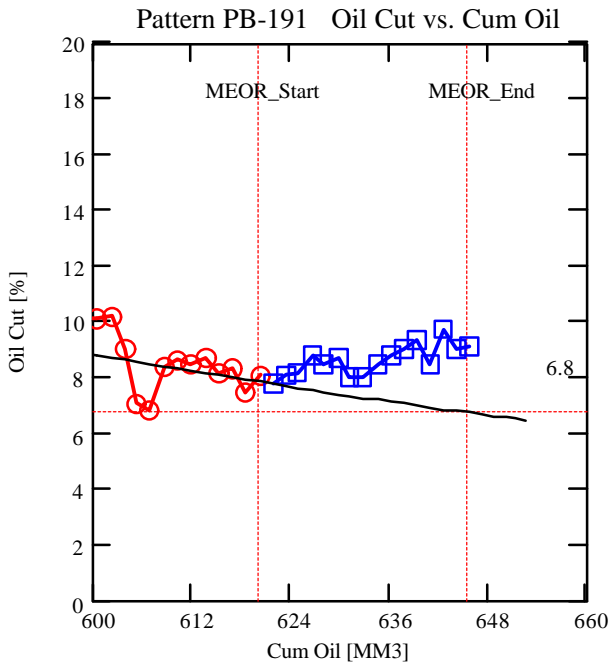


Figure 19: MEOR, Oil Cut Improvements (Two-Year Program)

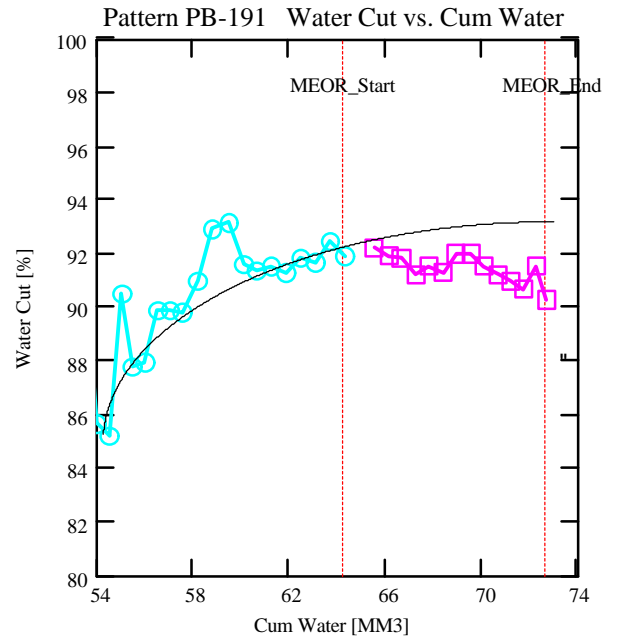


Figure 20: MEOR, Water Cut Improvements (Two-Year Program)

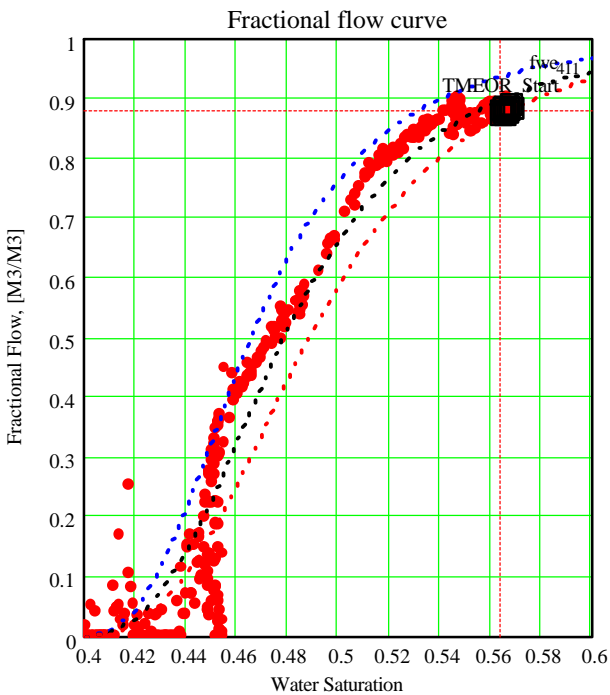


Figure 21: Pattern PB-191, Fractional Flow History and Water Saturation at MEOR Start Time

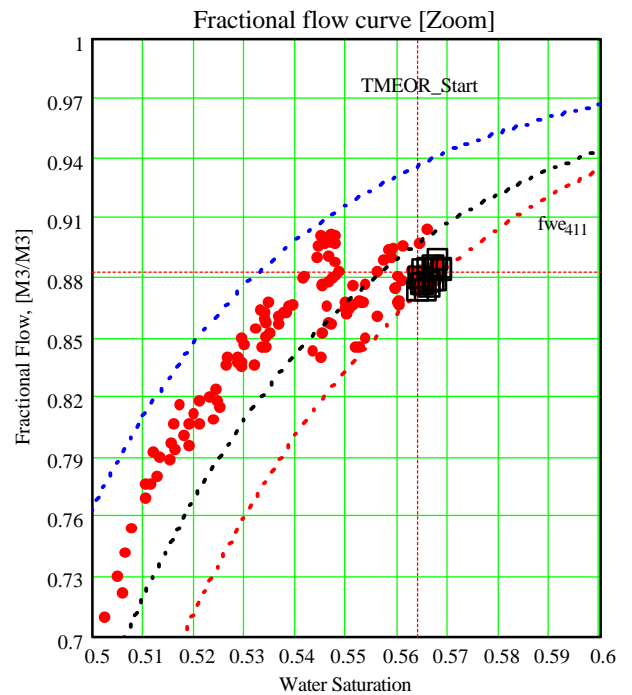


Figure 22: Zooming of Interest Region

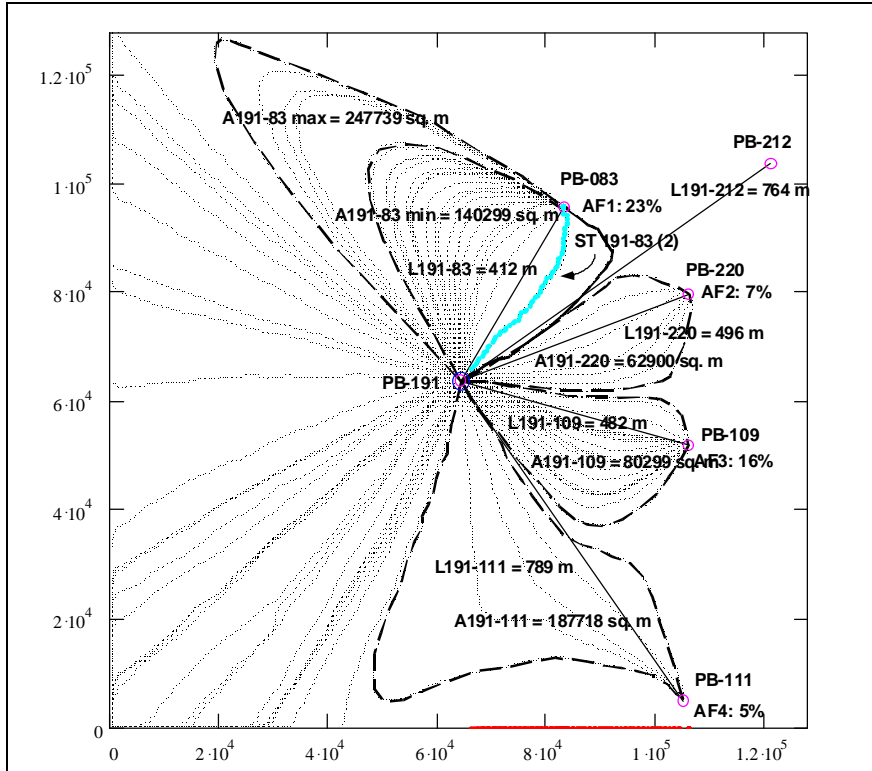


Figure 23: Flooded Areas and Water Injected Allocation Factors with PB-109 producer (active)

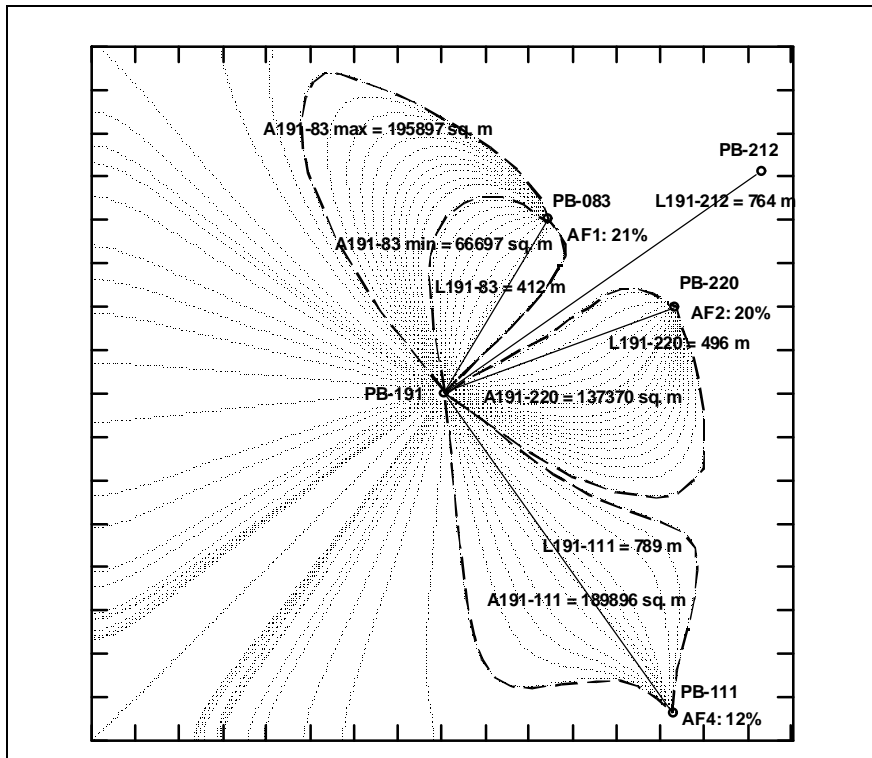


Figure 24: Flooded Areas and Water Injected Allocation Factors without PB-109 producer (inactive)

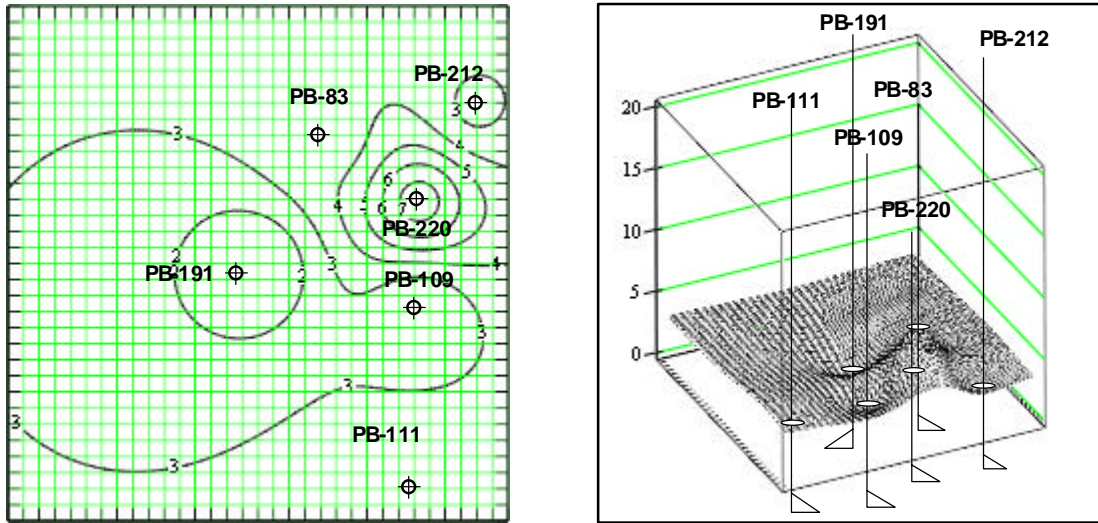


Figure 25: C2 Layer, VC Reservoir (PB-191 Pattern)

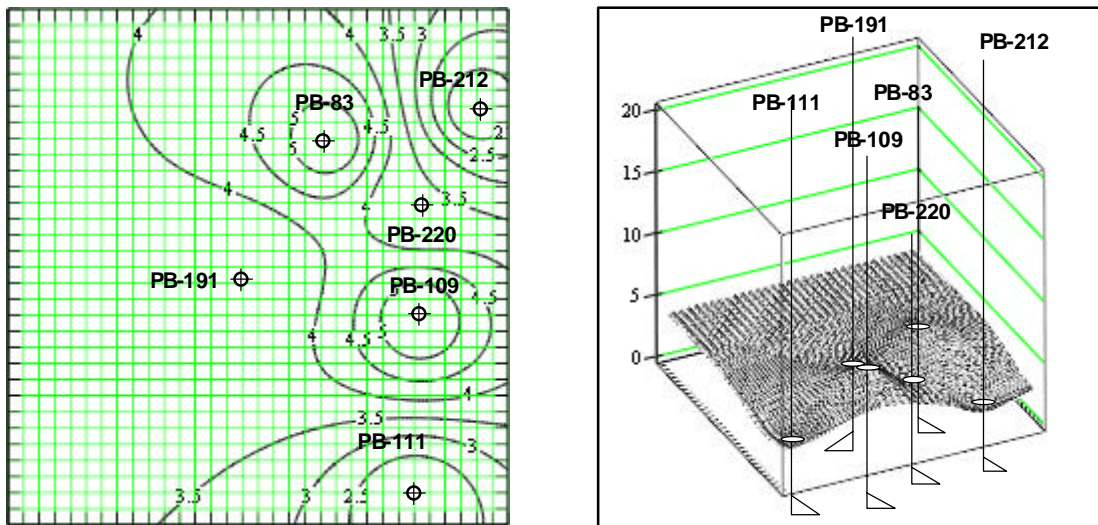


Figure 26: D2 Layer, VC Reservoir (PB-191 Pattern)

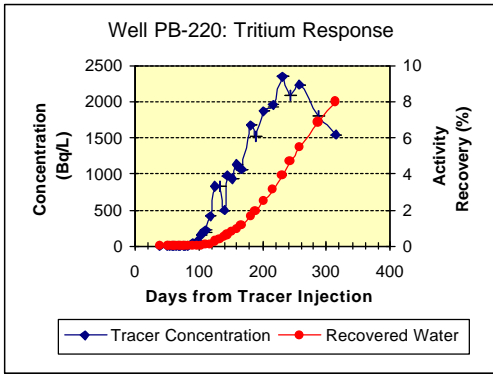


Figure 27: Tracer Analysis

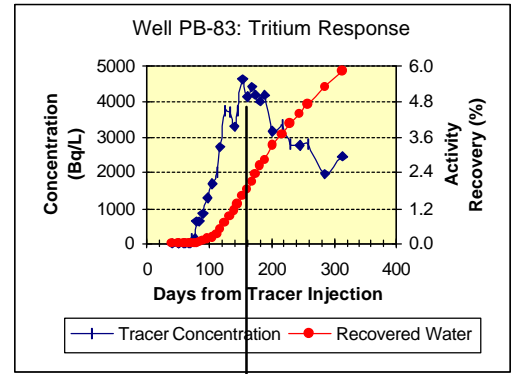


Figure 28: Tracer Analysis

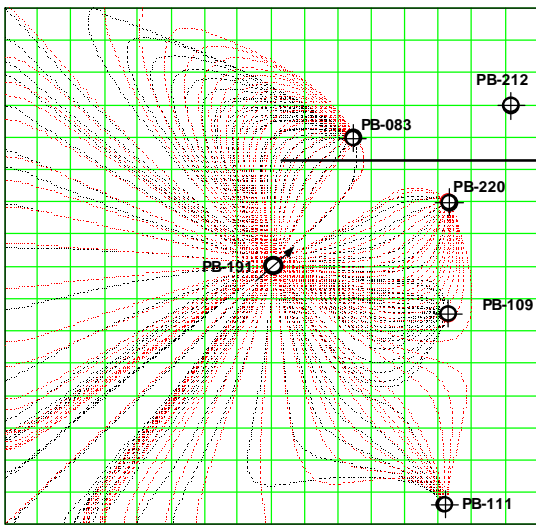


Figure 29: Streamlines and Tracer Analysis

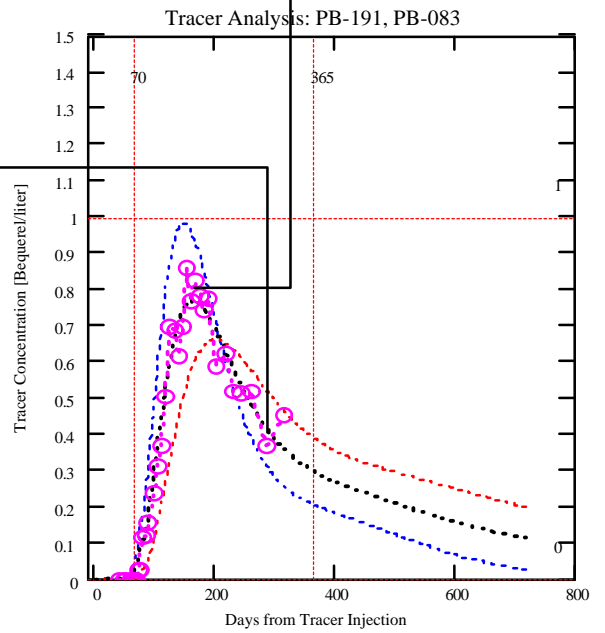


Figure 30: Matching Analysis for PB-83 Well

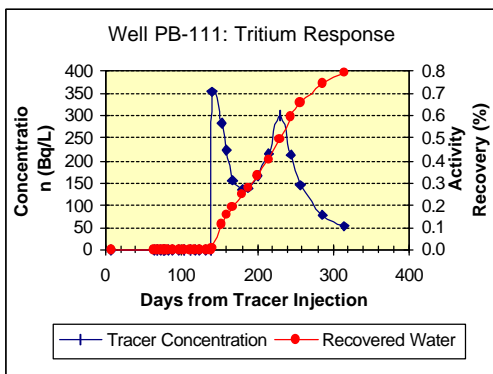


Figure 31: Tracer Analysis

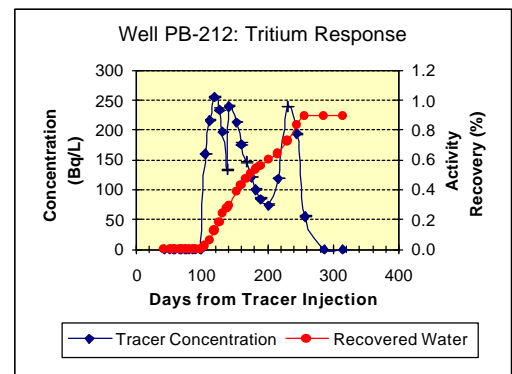
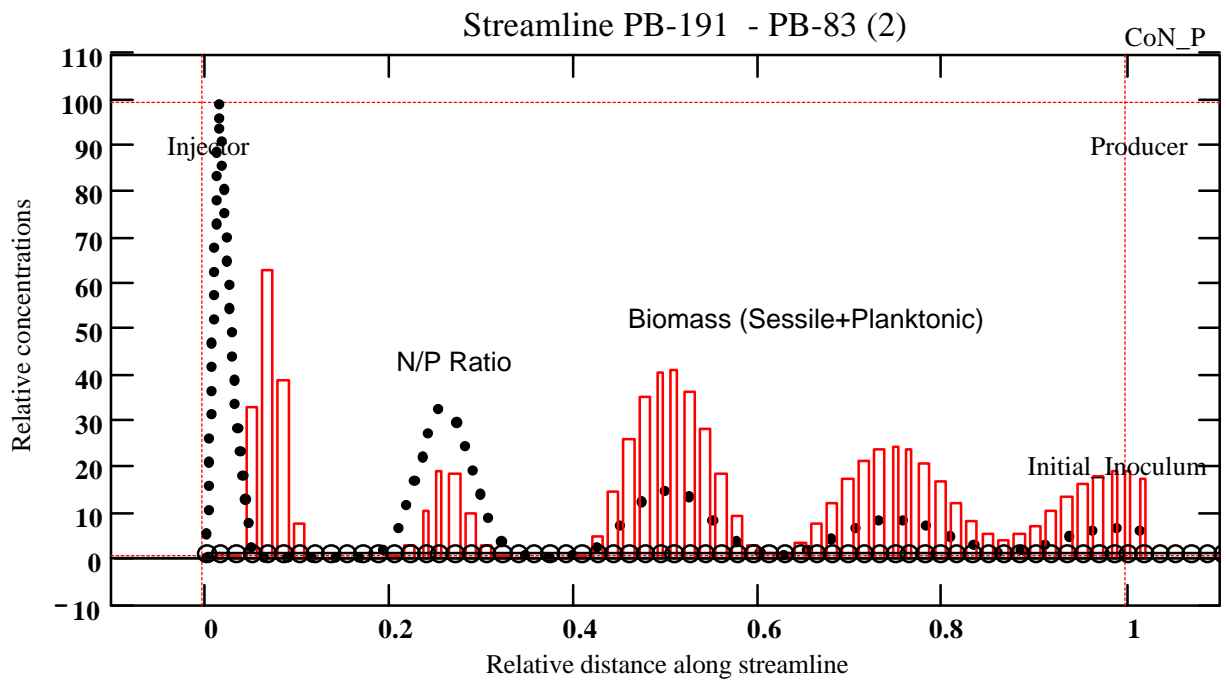


Figure 32: Tracer Analysis



Picture 33: Nutrient Attenuation Profile and Biomass Growing Inference by Simulation

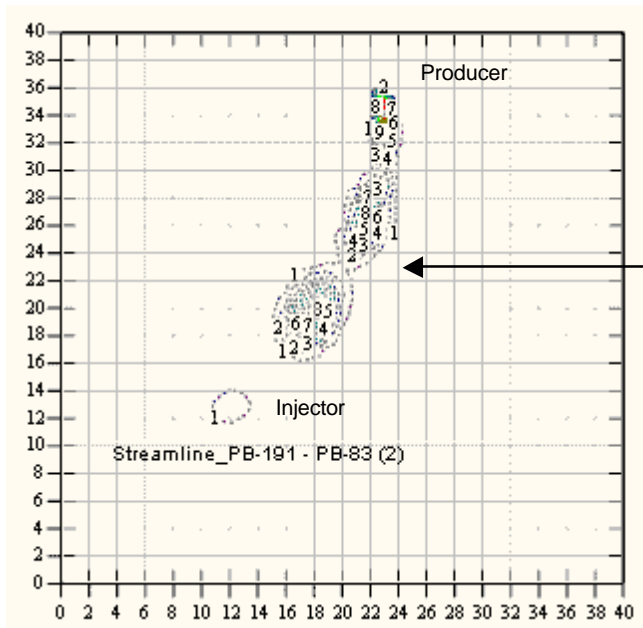


Figure 34: Biomass Growing Factors Mapped on Selected Streamline

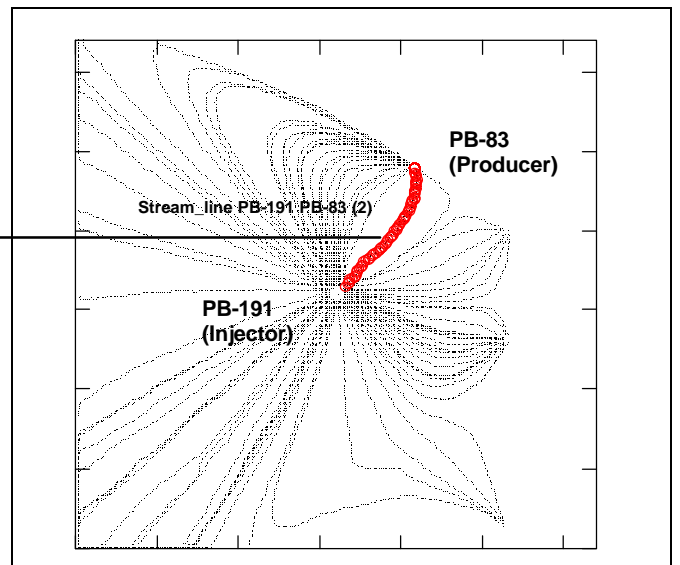


Figure 35: Streamline Under Analysis (ST_PB-191 PB-83 (2))

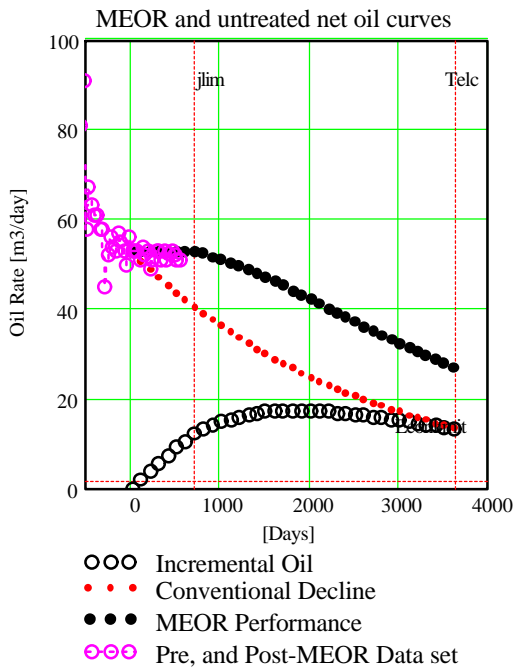


Figure 36: Economic Analysis (Case 1, Minimal)

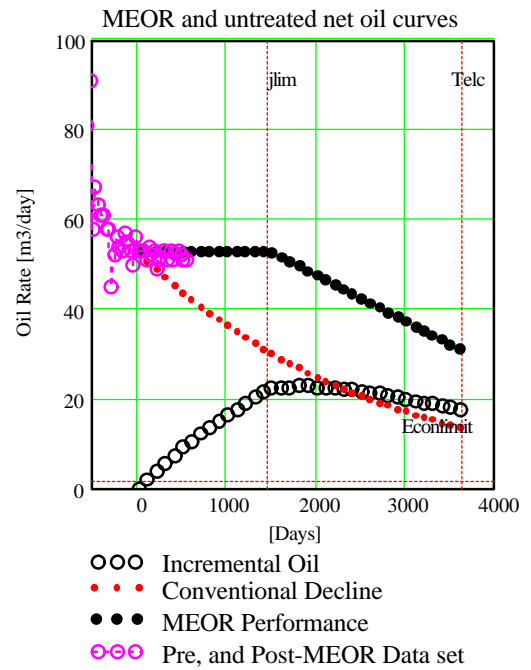


Figure 37: Economic Analysis (Case 3)

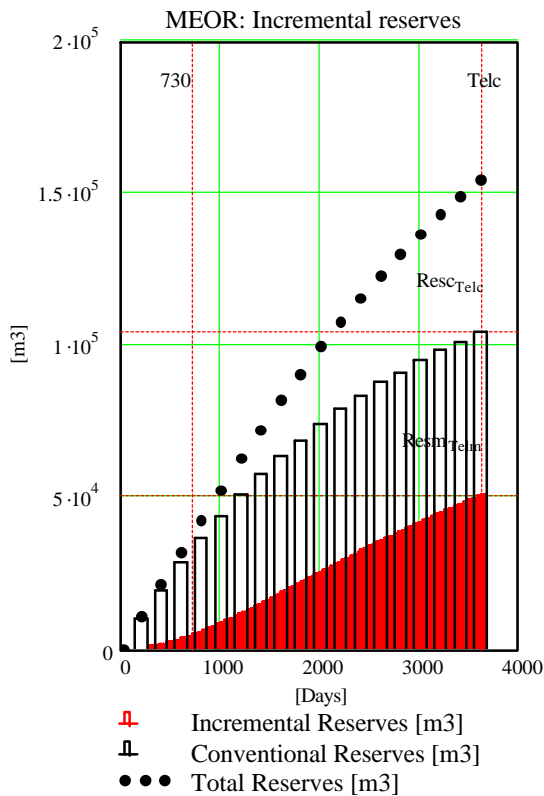


Figure 38: Reserves Analysis (Case 1, Minimal)

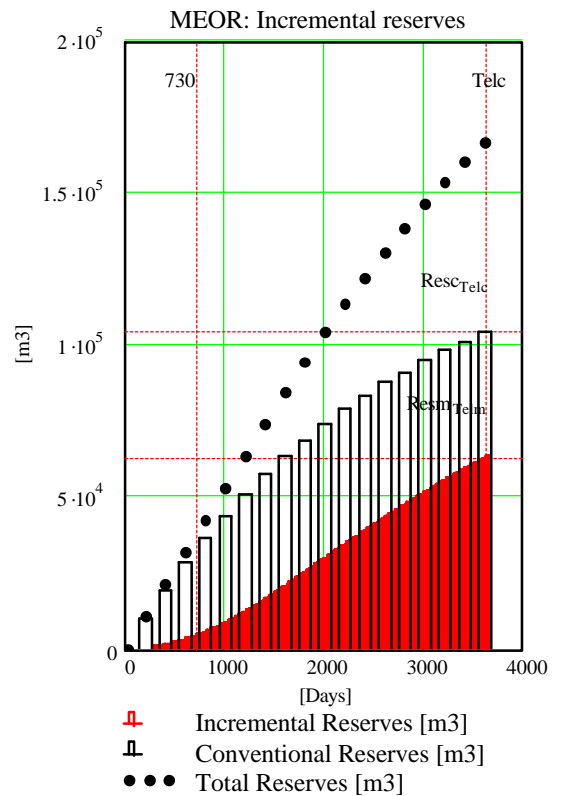


Figure 39: Reserves Analysis (Case 3)

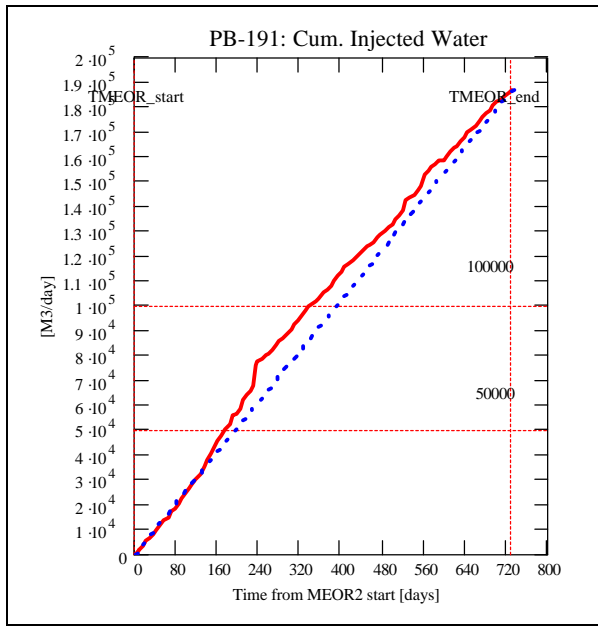


Figure 40: Two-Year MEOR program, Cumulative Water Injected

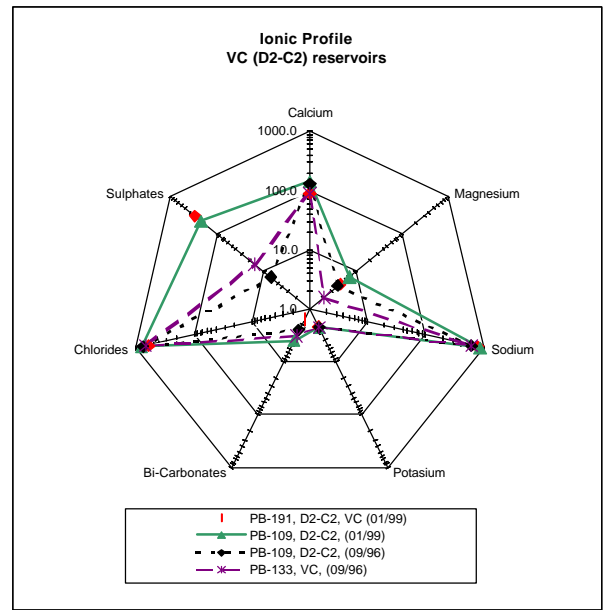


Figure 41: Formation Waters Chemical Characteristic

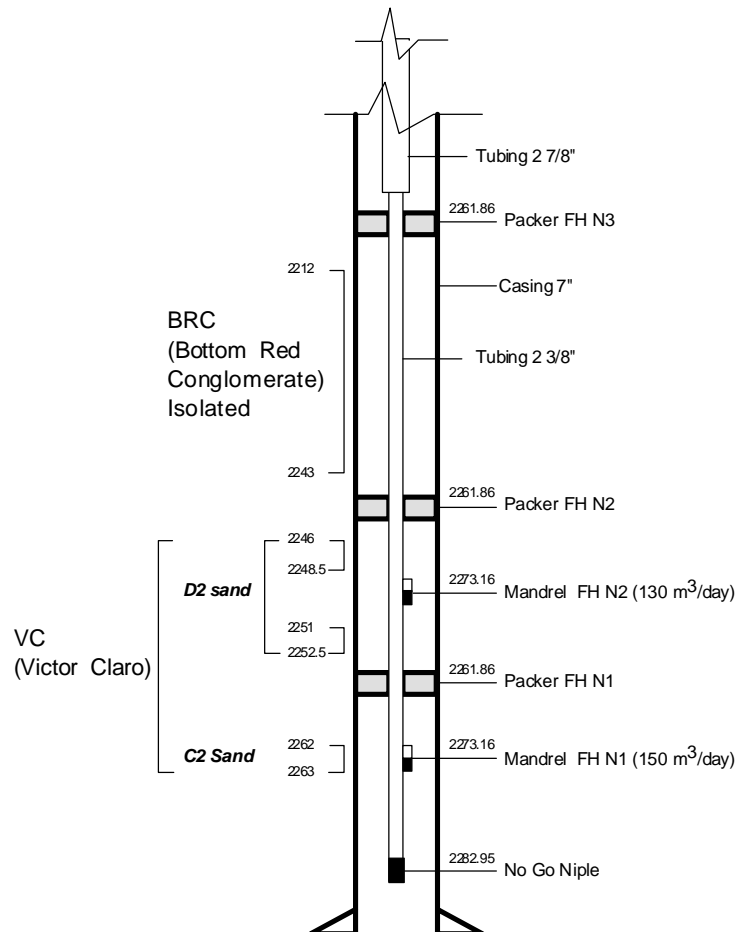


Figure 42: PB-191 (Injector), Selective Instalation in D2, C2 Sands

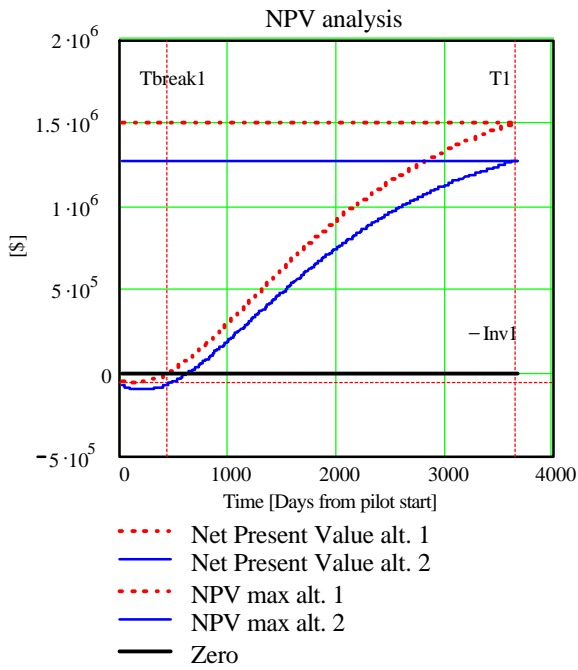


Figure 43: MEOR, NPV Evolution (Case 1, Minimal)

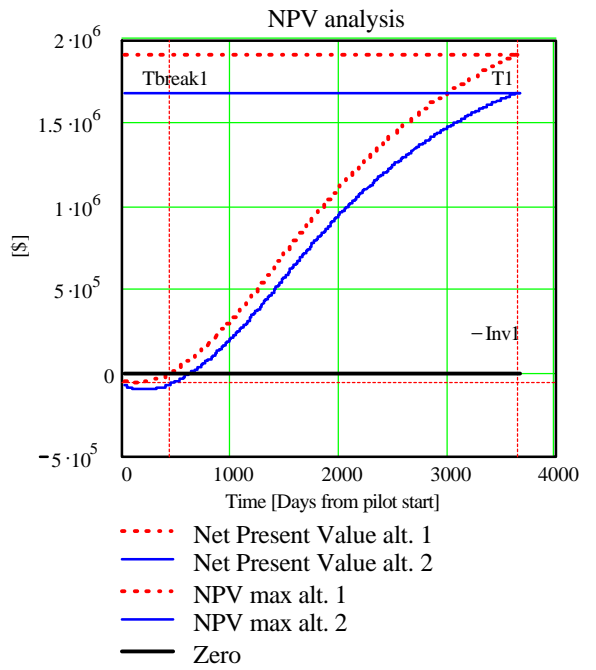


Figure 44: MEOR, NPV Evolution (Case 3)

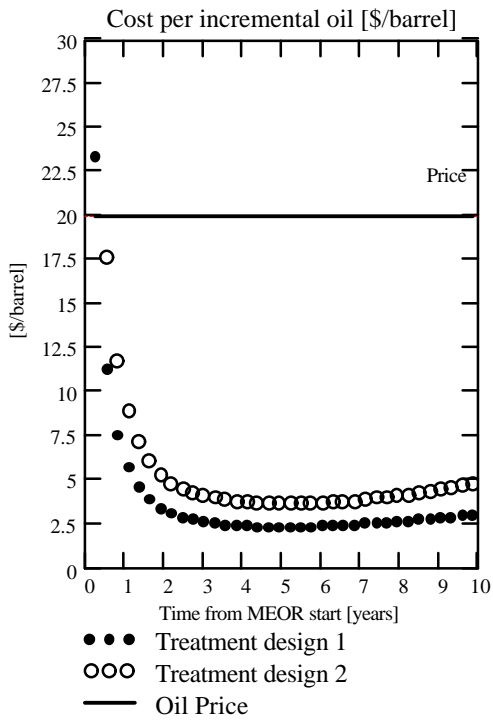


Figure 45: Cost per Incremental Barrel Evolution (Case 1, Minimal)

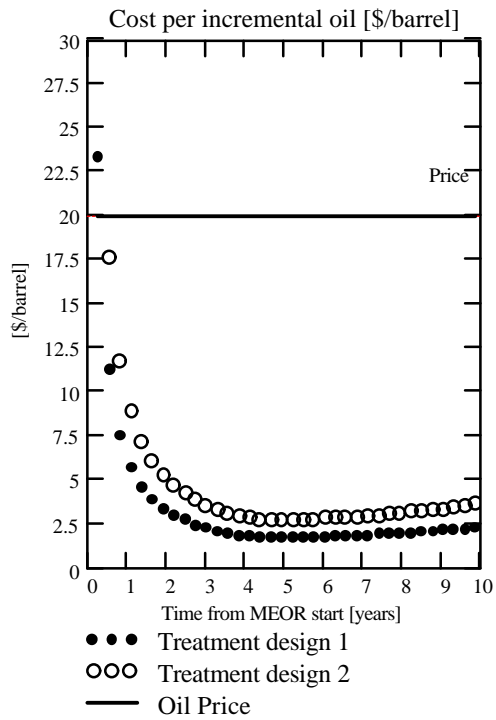


Figure 46: Cost per Incremental Barrel Evolution (Case 3)

TRC Reservoir		
General Information	Top Depth [m]	2190
	Average Pay Thickness [m]	7
	Productive Area [km ²]	32.2
	OOIP (MMm ³ std)	76.1
	Reservoir Temperature [°F]	226
	Initial Pressure [Psia]	2600
Petrophysical Properties	Saturation Pressure [Psi]	650
	Average Porosity [%]	18
	Average Permeability [mdarcys]	370
	Initial Water Saturation [%]	34
Fluid Properties	Residual Oil Saturation [%]	27
	Specific Gravity [°API]	30.2
	Oil Viscosity [cp]	4.5
	Oil Volume Factor [@ P _{initial}]	1.123
	Gas - Oil Ratio [m ³ /m ³]	20
Formation Water Salinity [ppm]	28100	

Table 3: TRC Reservoir Characteristic

BRC Reservoir		
General Information	Top Depth [m]	2220
	Average Pay Thickness [m]	11
	Productive Area [km ²]	66.4
	OOIP (MMm ³ std)	64.9
	Reservoir Temperature [°F]	230
	Initial Pressure [Psia]	2600
Petrophysical Properties	Saturation Pressure [Psi]	573
	Average Porosity [%]	18
	Average Permeability [mdarcys]	50
	Initial Water Saturation [%]	47
Fluid Properties	Residual Oil Saturation [%]	26
	Specific Gravity [°API]	29.2
	Oil Viscosity [cp]	9.5
	Oil Volume Factor [@ P _{initial}]	1154
	Gas - Oil Ratio [m ³ /m ³]	25
Formation Water Salinity [ppm]	36300	

Table 4: BRC Reservoir Characteristic

VC Reservoir		
General Information	Top Depth [m]	2255
	Average Pay Thickness [m]	7
	Productive Area [km ²]	75.0
	OOIP (MMm ³ std)	59.3
	Reservoir Temperature [°F]	230
	Initial Pressure [Psia]	2600
Petrophysical Properties	Saturation Pressure [Psi]	574
	Average Porosity [%]	20
	Average Permeability [mdarcys]	200
	Initial Water Saturation [%]	41
Fluid Properties	Residual Oil Saturation [%]	28
	Specific Gravity [°API]	29.0
	Oil Viscosity [cp]	10.0
	Oil Volume Factor [@ P _{initial}]	1.110
	Gas - Oil Ratio [m ³ /m ³]	15
Formation Water Salinity [ppm]	40000	

Table 5: VC Reservoir Characteristic (LRB is having similar parameters)

Well	Category	Formation	Sand	Geometry			Case A	Case B	Pethophysic
				Interval [m.b.s]	I-P Distance [m]	Thickness [m]	Flooded Area [m2]	Flooded Area [m2]	Porosity [%]
PB-191	Injector	VC	D2-C2	2246-2252.5/2262-2263	0	4	0	0	20
PB-83	First line - Producer	VC	D2-C2	2220-2224/2230-2233	412	9	195897	247739	21.2
PB-109	Non Active - Producer	VC	D2-C2	2227.5-2231.5/2240-2242	482	7.5	0	82299	15
PB-111	First line - Producer	VC	D2-C2	2226.5-2231.5/2237.5-2241	789	6	169896	187718	14.5
PB-212	Second line - Producer	VC	D2-C2	2207.5-2211/2216-2218	764	4.4	0	0	20.9
PB-220	First line - Producer	VC	D2-C2	2219-2222/2224.5-2235	496	11	137370	62900	14.5

Table 6: PB-191 Pattern Characteristics and Geometry

Well	Category	Formation	Sand	Fluid Saturations				PVT data
				S _{or} [%]	S _{oi} [%]	S _{wi} [%]	S _{wmst} [%]	B _{oi} @ 800 psi [rb/stb]
PB-191	Injector	VC	D2-C2	28	59	41	56.3	1.125
PB-83	First line - Producer	VC	D2-C2	28	59	41	56.3	1.125
PB-109	Non Active - Producer	VC	D2-C2	28	59	41	56.3	1.125
PB-111	First line - Producer	VC	D2-C2	28	59	41	56.3	1.125
PB-212	Second line - Producer	VC	D2-C2	28	59	41	56.3	1.125
PB-220	First line - Producer	VC	D2-C2	28	59	41	56.3	1.125

Table 7: PB-191 Pattern Saturations and Fluid Parameters Assumed at MEOR start

Oil in Place at MEOR start	
Case A [stm3]	Case B [stm3]
0.0	0.0
52161.9	65966.0
0.0	12920.9
20627.6	22791.5
0.0	0.0
30577.3	14001.0
Total A	Total B
103367	115679

Table 8: PB-191 Pattern Moveable Oil In Place

Well	Cum. Oil		Cum. Oil Difference [stm3]	MEOR/Conventional Decline Improvement		Fluid Allocation Factors Case B [%]	MEOR Fractional Recovery	
	At MEOR _{pilot start} [stm3]	At MEOR _{pilot end} [stm3]		From Case 1 [%]	From Case 3 [%]		Case 1 [%]	Case 3 [%]
PB-83	77	79.8	2.8	14.3	33.9	21	3.9	9.2
PB-109	99.7	0	0	0	0	0	0.0	0.0
PB-111	211.1	221.1	10	14.3	33.9	12	3.3	7.8
PB-212	12	16.7	4.7	0	0	0	0.0	0.0
PB-220	13.1	22.1	9	14.3	33.9	20	3.8	9.1

Table 9: Two-Year MEOR Program, Fractional Recovery Inference

Pattern PB-191				
Case: Baseline Hypthosis and MEOR Performance Extrapolation [1]				
Year from MEOR start	MEOR	Cost per	NPV: Net Present Value	
	Incremental Reserves	Incremental Barrel	at selected Price [WTI adjusted]	
	MIR	CIB	15 [\$ /b]	20 [\$ /b]
	[m3]	[\$/Barrel]	[M\$]	[M\$]
1	1255	6.05	-43.7	-21.8
2	3555	3.23	66.4	142.5
3	5178	2.63	227.1	372.2
4	5944	2.41	394.6	608.3
5	6270	2.35	549.4	826.2

Table 10: MEOR, Economic Analysis (Case 1)

Pattern PB-191				
Case: Baseline Hypthosis and MEOR Performance Extrapolation [2]				
Year from MEOR start	MEOR	Cost per	NPV: Net Present Value	
	Incremental Reserves	Incremental Barrel	at selected Price [WTI adjusted]	
	MIR	CIB	15 [\$ /b]	20 [\$ /b]
	[m3]	[\$/Barrel]	[M\$]	[M\$]
1	1255	6.05	-43.5	-22.0
2	3555	3.23	66.4	142.5
3	5561	2.29	242.2	392.0
4	7310	1.83	456.5	691.7
5	8244	1.79	670.8	989.4

Table 11: MEOR, Economic Analysis (Case 2)

Pattern PB-191				
Case: Baseline Hypthosis and MEOR Performance Extrapolation [3]				
Year from MEOR start	MEOR	Cost per	NPV: Net Present Value	
	Incremental Reserves	Incremental Barrel	at selected Price [WTI adjusted]	
	MIR	CIB	15 [\$ /b]	20 [\$ /b]
	[m3]	[\$/Barrel]	[M\$]	[M\$]
1	3339	2.98	65.8	124.6
2	6419	1.92	308.1	464.9
3	7975	1.85	581.2	844.4
4	7888	1.94	817.0	1171.0
5	7308	2.15	1004.0	1432.0

Table 12: MEOR, Economic Analysis (Case 3)

Pattern PB-191				
Case: Baseline Hypthosis and MEOR Performance Extrapolation [4]				
Year from MEOR start	MEOR	Cost per	NPV: Net Present Value	
	Incremental Reserves	Incremental Barrel	at selected Price [WTI adjusted]	
	MIR	CIB	15 [\$ /b]	20 [\$ /b]
	[m3]	[\$/Barrel]	[M\$]	[M\$]
1	3339	2.98	65.8	124.6
2	6419	1.92	308.1	464.9
3	8902	1.49	617.4	892.7
4	10900	1.26	957.9	1359.0
5	11240	1.39	1264.0	1778.0

Table 13: MEOR, Economic Analysis (Case 4)

Pattern PB-191				
Short Term Analysis				
Case	Investment	Pay Out		Annual Cost
		15 [\$ /b]	20 [\$ /b]	
	[M\$]	[Days from MEOR start]	[Days from MEOR start]	[Average]
1	26.1	545	434	52.8
2	26.1	545	434	52.8
3	26.1	159	217	52.8
4	26.1	159	217	52.8

Table 14: MEOR Cases Summary, Short Term Indexes

Annex A

Treatability Indexes

$$NI = \left(\frac{(\mu_{pp}^{control})_{\min SR} - (\mu_{pp}^{control})_{\max SR}}{(\mu_{pp}^{inoculated})_{\min SR} - (\mu_{pp}^{inoculated})_{\max SR}} \right)_{TMD} \quad \text{..... (Eq. 1)}$$

$$DV = \left(\frac{\sum_{i=\min SR}^{\max SR} (\mu_{pp_i})^{control} - \sum_{i=\min SR}^{\max SR} (\mu_{pp_i})^{inoculated}}{\sum_{i=\min SR}^{\max SR} (\mu_{pp_i})^{control}} \right)_{TMD} \quad \text{..... (Eq.2)}$$

$$EOR = \frac{1}{1 - DV} \quad \text{..... (Eq. 3)}$$

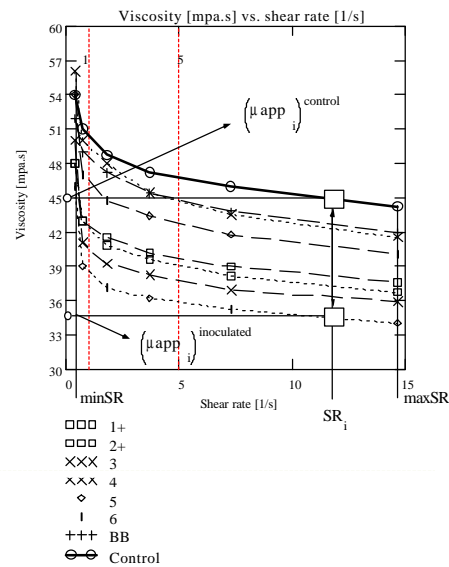


Figure 47: Methodology to Analyze Microbial Sub-communities Influence in Oils

Annex B

Geochemical Methods and instrumentation

Fractionation by Liquid Chromatography: Asphaltenes are precipitated with hexane and soluble fraction is separated into saturate hydrocarbons, aromatic hydrocarbons and resins/NSO compounds on a silica column by successive elution with hexane, benzene, and benzene-methanol. The solvents are evaporated and weight percent of each fraction is determined.

Gas Chromatography (GC): The whole oil is analyzed with a Varian model 3300 gas chromatograph fitted with a 50 m fused silica capillary column. Analytical data are processed with a Nelson Analytical Model 3000 chromatography data system.

Very High Resolution C₇ Gas Chromatography: A sample of oil is injected directly into a Varian model 3400 gas chromatograph fitted with a split injector and a Quadrex 100 meter fused silica capillary column. The GC run is isothermal at 35°C while collecting the data from C₂ – C₈, then heated to purge the remaining sample from the column. Analytical data are processed with a Nelson Analytical model 3000 chromatographic data system and IBM computer hardware.

Biomarker Analysis (GC-MS): The saturate or aromatic fractions separated by liquid chromatography from whole oils or source rocks extracts are injected into a HP5890 gas chromatograph coupled to the HP5971A MSD. The **Selected Ion Monitoring (SIM)** capabilities of the computer data acquisition system permit specific ions to be monitored. Ion m/z = 191 allows characterization of specific saturate triterpenoid compounds and m/z = 217 certain saturate steranes. The ions m/z = 253 and 231 are respectively specific for mono and triaromatic steroids; m/z = 156 and 170, for C₂-naphthalenes; m/z = 178 and 192, for phenanthrene and methylphenanthrenes, respectively; m/z = 184 and 198, for dibenzothiophene and methyl dibenzothiophene, respectively.

Rheological Methods and instrumentation

Basically, lab procedures consisted of serial inoculations of oil with different microbial sub communities, followed with 48 to 96 hours of controlled atmosphere incubation program at specific temperatures. Fluid samples and their replicates are taken at wellhead conditions for every producer well pertaining to the pattern under screening following a specific timetable during pre- and post-MEOR stages. The oil and formation water is separated from the original sample and divided in a set of small portions to be inoculated and coded with different combination of anaerobic-facultative microorganisms. The serial rheology (using Brookfield DVIII viscometer with ULA adapters) analysis produces control and inoculated set of apparent viscosity vs. shear rate and apparent viscosity vs. temperature curves permitting to elaborate **MEOR treatability indexes (NI, DV and EOR)**. These Indexes help to decide the best combination of microbial products to use with the target oil/formation water combination under testing. In waterflooding applications, the control (non inoculated samples) and inoculated bottles are incubated at specific temperatures for at least a 400 hours period. Every 24 to 48 hours is running a serial rheology procedure on control and inoculated sub-samples taken from the oil and water phases from the corresponding serial bottles. To track compositional changes and correlate with viscosity alterations, small portions of oil (1 ml) are sampled to run High Resolution Whole Oil Chromatography. Microbial activity in water phase is checked periodically. The study of external solvents (nC₁₂-nC₁₄ alkane range) matched with the biogenerated ones (internal solvents) is also a common practice during pre-MEOR evaluation. Serial bottles of inoculated oils are incubated and tested upto reach 400 hours of residence time.

Annex C

Thompson Compositional Values

$$H = \left[\frac{k}{\sum_{i=c}^{i=l} \text{Compound } i} \right] \times 100 \dots\dots\dots (\text{Eq. 4})$$

$$F = \frac{k}{l} \dots\dots\dots (\text{Eq. 5})$$

$$B = \frac{m}{k} \dots\dots\dots (\text{Eq. 6})$$

$$I = \left(\frac{d + g}{h + i} \right) \dots\dots\dots (\text{Eq. 7})$$

$$A = \frac{b}{a} \dots\dots\dots (\text{Eq. 8})$$

$$R = \frac{k}{d} \dots\dots\dots (\text{Eq. 9})$$

All values are normalized areas [%] from GC chromatography.

With:

- a* = *n* - HEXANE
- b* = BENCENE
- c* = CYCLOHEXANE
- d* = 2 - METHYLPENTANE
- e* = 2,3 - DIMETHYLHEXANE
- f* = 1,1 - DMCP
- g* = 3 - METHYLHEXANE
- h* = 1 - cis, 3 - DMCP
- i* = 1 - trans, 3 - DMCP + 3 - EP
- j* = 1 - trans, 2 - DMCP
- k* = *n* - HEPTANE
- l* = METHYLCYCLOHEXANE
- m* = TOLUENE

- H* : Heptane Value
- F* : Paraffinity
- B* : Aromaticity (1)
- I* : Isoheptane Value
- A* : Aromaticity (2)
- R* : Paraffin Branching value

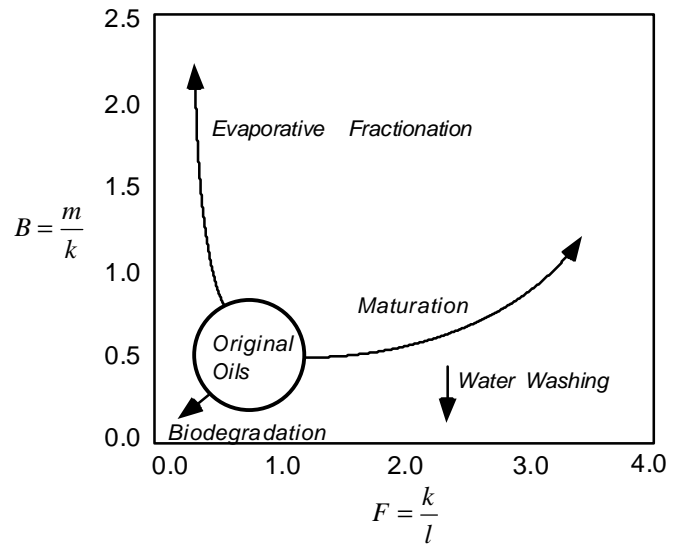


Figure 48: Interpretation Guide (Table 2)

Annex D

Calculation of Recovery Factor (RF) using reservoir discretization schemes based on streamlines patterns:

$$RF_{to}^t = \frac{\sum_{producer=1}^{producer=M} \left(\int_{to}^t q_o(t) \cdot dt \right)}{\sum_{injector=1}^{injector=L} \sum_{producer=1}^{producer=M} \sum_{streamtube=1}^{streamtube=N} \left(\sum_{\mathbf{x}_o}^{\mathbf{x}_f} A_{\mathbf{x},to} \cdot h_{\mathbf{x},to} \cdot f_{\mathbf{x},to} \cdot \left(\frac{(1 - Sor - Swirr - Swmov)_{\mathbf{x},to}}{Bo_{\mathbf{x},to}} \right) \right)_{Streamline(k)}} \quad \text{.....(Eq. 10)}$$

$$MOIP_{Streamtube(k)}^{to} = \left(\sum_{\mathbf{x}_o}^{\mathbf{x}_f} A_{\mathbf{x},to} \cdot h_{\mathbf{x},to} \cdot f_{\mathbf{x},to} \cdot \left(\frac{(1 - Sor - Swirr - Swmov)_{\mathbf{x},to}}{Bo_{\mathbf{x},to}} \right) \right)_{Streamline(k)} \quad \text{.....(Eq. 11)}$$

With:

RF_{to}^t = recovery factor considering (t-to) time interval, stock tank condition

$MOIP_{Streamline(k)}^{to}$ = moveable oil in place at time to and for streamline k, stock tank conditions, [std m³]

$A_{\mathbf{x},to}$ = cell area at position \mathbf{x} , along streamline, time to, [m²]

$h_{\mathbf{x},to}$ = net interval at position \mathbf{x} along streamline, time to, [m]

$f_{\mathbf{x},to}$ = porosity at position \mathbf{x} along streamline, time to

$Bo_{\mathbf{x},to}$ = volume factor at position \mathbf{x} , along streamline, time to, [std m³/reservoir m³]

$Swmov_{\mathbf{x},to}$ = moveable watersaturation at position \mathbf{x} along streamline, time to

Bo = volume factor, [std m³/reservoir m³]

N = number of active streamlines connecting an especific pair of producer-injector wells

M = number of active producers in the pattern under evaluation

L = number of active injectors in the pattern under evaluation

$Swmov$ = moveable water saturation at MEOR start

$Swirr$ = irreducible water saturation

Sor = residual oil saturation

$q_{o(t)}$ = oil rate at time t, [m³/day]

t =final time [days]

to =initial time[days]

Assumptions:

- 1) Monolayer reservoir
- 2) Moveable oil as reference
- 3) No inter-layer cross flow
- 4) Convective-diffusive flow
- 5) Active streamlines pattern remain stable during (t-to)
- 6) Streamline pattern validated by tracers and subjacent geology (micro and macro heterogeneities)

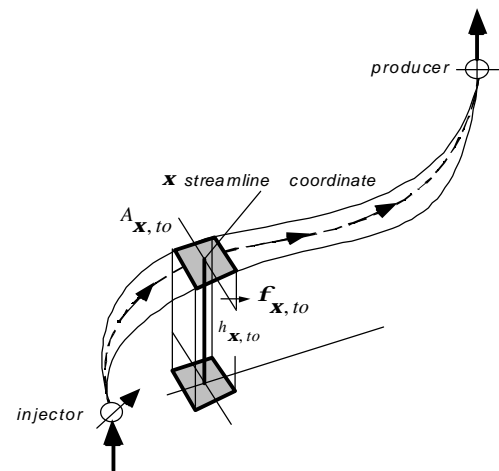


Figure 49: Reservoir Discretization, Streamline (k) and Boundaries

Nomenclature

μ_{app} = apparent viscosity, [cp]
 B_{oi} = volume factor, [std m^3 /reservoir m^3]
 DV = Delta Viscosity index
 EOR = EOR index
 GOR = gas oil relationship, [m^3/m^3]
 SR = shear rate, [1/s]
 $maxSR$ = maximum explored Shear Rate, [1/s]
 $minSR$ = minimum explored Shear Rate, [1/s]
 $MEOR_{(t_i)}$ = productivity index ratio, MEOR performance index, dimensionless
 NI = Newtonian index
 $Q_{meor(t_i)}$ = oil rate after MEOR, [m^3/day]
 $Q_{o(t_i)}$ = oil rate before MEOR, [m^3/day]
 $q_{o(t)}$ = oil rate at time t , [m^3/day]
 S_o = oil saturation
 S_w = water saturation
 S_{wmst} = water saturation at MEOR start
 S_{wirr} = irreducible water saturation
 S_{wc} = connate water saturation
 S_{or} = residual oil saturation
 $K_{ro}(S_{wirr})$ = oil relative permeability at S_{wirr}
 $K_{rw}(S_{or})$ = water relative permeability at S_{or}
 TMD = Temperature of Maximum Discrimination of rheological properties, [$^{\circ}F$]
 J_{lim} = post MEOR decline commencement year
 T_{elc} = time to economic limit
 N/P = nitrogen to phosphorus ratio
 $Co\ N-P$ = Initial concentration of nitrogen and phosphorus [ppm]
 $I-P$ Distance = injector to producer distance [m]
 D_{MEOR} = effective MEOR decline [1/day]
 D_{conv} = effective conventional decline [1/day]

Subscripts

$control$ = original sample condition (pre MEOR)
 $inoculated$ = Inoculated sample condition
 e = natural logarithms base, 2.7172...
 i = data point, spatial reference
 j = producer reference
 x = streamline axial coordinate
 m = microbial enhanced
 max = maximum
 min = minimum
 o = original, initial
 t = time