ENHANCED OIL RECOVERY – ALKALINE SURFACTANT POLYMER FLOODING (A COMPLETE OVERVIEW)

BY

AMIT PANWAR (R010205009)

ASHISH PATHAK (R010205012)

COLLEGE OF ENGINEERING

UNIVERSITY OF PETROLEUM & ENERGY STUDIES,DEHRADUN

'Enhanced Oil Recovery: Alkaline Surfactant Polymer Flooding

(A Complete Overview)'

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

Bachelor of Technology (Applied Petroleum Engineering)

Batch – (September 2005 – May 2009)

Submitted to:

College of Engineering

Under the guidance of

Mr. Rajeshwar Mahajan

(Asst. Professor, UPES)

Submitted by:

Amit Panwar

&

Ashish Pathak

University of Petroleum & Energy Studies ,Dehradun

May 2009

UNIVERSITY OF PETROLEUM & ENERGY STUDIES

CERTIFICATE

This is to certify that the work content in this report titled "ENHANCED OIL RECOVERY:ALKALINE SURFACTANT POLYMER FLOODING(A COMPLETE OVERVIEW)" has been carried out by **Mr. Amit Panwar** and **Mr. Ashish Pathak** under my supervision and has not been submitted elsewhere for a degree.

Rajeshwar Mahajan
11.05.09.

Mr. Rajeshwar Mahajan
Assistant Professor
College of Engineering

Acknowledgment

We would like to express our sincere thanks to University of Petroleum and Energy Studies for giving us an opportunity to work on the project "Enhanced Oil Recovery: Alkaline Surfactant Polymer Flooding-A Complete Overview".

The authors are profoundly grateful to Dr. B.P Pandey for his valuable suggestions and inspiration for the project.

The authors are also thankful to Shri.M.K.Saxena(Reservoir Engineer,KDMIPE,ONGC), Shri. Rahul Verma(Senior Engineer,Drilling,ONGC,Dehradun), Shri.P.K.Bhowmick(Head ED,KDMIPE,ONGC,Dehradun), Mr. Chaman Lal (GM,Reservoir Deptt.,KDMIPE,ONGC) and Dr. Pushpa Sharma(KDMIPE,ONGC,Dehradun) for their valuable discussions and guidance for the project.

The authors are also thankful and indebted to Prof. Rajeshwar Mahajan for his valuable suggestions, keen interest and constructive guidance, timely and generous help beyond measures at all the stages during the progress of the project work.

Amit Panwar

Ashish Pathak

B. Tech. (A.P.E.)

University of Petroleum and Energy Studies

Abstract

Nearly $2.0*10^{12}$ barrels (0.3 × 1012 m^3) of conventional oil and 5.0 × 1012 barrels (0.8 × 1012 m^3) of heavy oil will remain in reservoirs worldwide after conventional recovery methods have been exhausted. Much of this oil would be recovered by Enhanced Oil Recovery (EOR) methods, which are part of the general scheme of Improved Oil Recovery (IOR). The choice of the method and the expected recovery depends on many considerations, economic as well as technological.

This Project discusses the various EOR Methods (thermal and non-thermal) and their screening criteria's as well. The reservoir properties like the porosity, permeability, wettability, etc. and the reservoir temperature, pressure and depth are some of the factors that are responsible for the applicability of different EOR processes for different reservoirs.

The project lays emphasis on the various chemical recovery methods, with special emphasis on ASP (Alkaline Surfactant and Polymer Flooding). ASP flooding combines the effect of alkaline, surfactant and polymer technology to achieve surplus recovery of oil, which is more that the individual recoveries obtained by either alkaline, surfactant or polymer flooding alone.

ASP flooding is effective in recovering unswept oil by improving the mobility ratio (by the use of polymer), and by reducing residual oil saturation or decreasing the interfacial tension between oil and water (by using surfactants and alkalis). Parameters such as mineralogy, permeability and viscosity ranges, temperature, salinity, have an impact on the feasibility of the process and also on the economics.

One of the key oil recovery problems in oil wet reservoirs is overcoming the interfacial tension (IFT) force that holds the oil to the surface of the rock. In water wet reservoirs surface tension leads to the creation of bubbles of oil, which leads to the blockage of pore spaces. Thus, IFT is the primary reason because of which the reservoirs become increasingly impermeable to oil, as the water saturation increases. If the interfacial tension is brought down to about 10^{-3} dynes/cm, then additional recovery of about 10-20% of IOIP can be expected. Alkalis and Surfactants are helpful in reducing the IFT between oil and water by 100 folds and thus help in recovery of surplus oil from the reservoir.

The project also deals with a case study of the application of ASP flooding, in field X sand S-II on a pilot scale. The economics for the project has also been worked out.

Further some examples of fields where ASP flooding has been conducted is included in the project, and also it's merits and demerits are included.

Contents

LIST OF TABLES i
LIST OF FIGURES ii
ABBREVIATIONS v

CHAPTER 1: INTRODUCTION 1

1.1 Primary Recovery 1
1.1.1 Depletion Drive 1
1.1.2 Gas Cap Expansion 1
1.1.3 Water Drive 2
1.1.4 Gravity Drainage 2
1.2 Secondary Recovery 2
1.2.1 Water Flooding 2
1.2.2 Requirement of Injection Water 3
1.2.3 Sources of Water for Injection 3
1.2.4 Studies Required for Designing Water for Injection 3
1.3 Tertiary Recovery/EOR Phase 4
1.3.1 Concept Involved in the recovery processes 4

CHAPTER 2: ENHANCED OIL RECOVERY (VARIOUS PROCESSES) 5
2.1 **What is Enhanced Oil Recovery** 5
2.2 **The EOR Methods** 7
2.3 **Recovery Efficiency** 7
2.3.1 Volumetric Sweep Efficiency 7
2.3.2 Displacement Efficiency 8
2.3.3 Efficiency due to conformance 8
2.4 **Mobility and Mobility Ratio** 8
2.5 **Recovery Efficiency (Factors) for EOR Processes** 12
2.6 **Screening Criteria of Various EOR Processes** 12
2.6.1 Screening Criteria of Various EOR Processes(Based on API Gravity of Crude Oil) 12
2.6.2 PREFERRED OIL VISCOSITY RANGES FOR ENHANCED RECOVERY METHODS 13
2.6.3 PERMEABILITY GUIDES FOR ENHANCED RECOVERY METHODS 13
2.6.4 DEPTH LIMITATION FOR ENHANCED OIL RECOVERY METHODS 14
2.7 **Miscible Flooding Methods** 14
2.7.1 Miscible Slug Process 14
2.7.2 Enriched Gas Drive 15
2.7.3 Vaporizing Gas Drive 15
2.7.4 CO_2 Miscible 15
2.7.5 N_2 Miscible 16
2.8 **Thermal EOR Methods** 16
2.8.1 Cyclic Steam Injection 17
2.8.2 Cyclic Steam Injection 18

2.8.3 Steam Assisted Gravity Drainage (SAGD) 18
2.8.4 In Situ Combustion...19
2.9 **Chemical Flooding Methods**...20
2.9.1 Surfactants and Surfactant Assisted Water Flood...21
2.9.2 Polymer...22
2.9.3 Alkaline...25
2.9.4 Micellar Flooding...27
2.9.5 Micellar-Polymer Flooding...28
2.10 **Alkaline Surfactant Polymer Flooding**...29
2.10.1 Mechanism...29
2.10.2 Several variations...29

CHAPTER 3 – CASE STUDY 31
3.1 INTRODUCTION...31
3.1.1 GENERAL HISTORY...31
3.1.2 ALKALI-SURFACTANT –POLYMER (ASP) FLOODING & ITS SCOPE
FOR IMPROVING OIL RECOVERY IN FIELD- X SAND S-II...32
3.2 RESERVOIR GEOLOGY..34
3.2.1 STRUCTURE...34
3.2.2 SAND MODEL...34
3.2.3FIELD X UNIT SUB-LAYERS...35
3.2.4LITHOLOGY..35
**3.3FIELD DEVELOPMENT & RESERVOIR
CHARACTERISTICS**...36
3.3.1 FIELD DEVELOPMENT..36
3.3.2 RESERVOIR, ROCK AND FLUID PROPERTIES..36
3.3.3 RESERVOIR PERMEABILITY VARIATION...37
3.3.4 RESERVOIR OIL VISCOSITY VARIATION...38
3.3.5 ADVERSE MOBILITY RATIO..38
3.4 **LABORATORY STUDIES**..40
3.4.1 BACK GROUND..40
3.4.2 BRIEF RESULTS...41
3.4.3 SLUG SIZE OPTIMIZATION...42
3.4.4 DISPLACEMENT EFFICIENCY AT TERTIARY (ROS) STAGE..42
3.4.5 DISPLACEMENT EFFICIENCY BY POLYMER FLOODING...43
3.5 **ASP FLOOD PERFORMANCE CALCULATION**...45
3.5.1 CAPILLARY NUMBER CORRELATIONS METHOD...45
3.5.2 FRACTIONAL FLOW THEORY, BUCKLEY-LEVERETT METHOD...46
3.5.3 DISPLACEMENT EFFICIENCFY METHOD...48
3.6 **FIELD PILOT DESIGN**..50
3.6.1 SITE AND PATTERN SELECTION..50

3.6.2 DETAILS OF PILOT WELLS....51
3.6.3 PETRO-PHYSICAL PROPERTIES....51
3.6.4 PRESSURE-PRODUCTION....51
3.6.5 PRE-PILOT EVALUTION....51
3.6.6 FLUID INJECTION PROGRAMME....52
3.6.7 ASP SLUG....52
3.6.8 MOBILITY BUFFER....52
3.6.9 CHASE WATER....53
3.6.10 SURFACE FACILITIES....53
3.6.11 PILOT PERFORMANCE MONITORING PROGRAMME....55
3.7 **TECHNO-EONOMIC ANALYSIS**....56
3.7.1 ECONOMIC CALCULATION 57
3.8 **CONCLUSIONS AND RECOMMENDATIONS**....59
3.8.1 CONCLUSIONS 59
3.8.2 RECOMMENDATIONS....60

CHAPTER 4- CASE STUDIES of SOME OTHER FIELDS....99

4.1 Daqing Oil Field....99
4.1.1 ASP Flooding in Daqing Oil Field....99
4.2 B1-FBX Large Spacing ASP Pilot Test....100
4.3 XII-Z Commercial-Scale ASP Test....101
4.4 Testing the ASP Process in Other Oil Fields....101
4.5 Karamay....102
4.6 Conclusions From the ASP Pilot Tests....102
4.7 ASP Pilot Lawrence field Illinois....104
4.7.1 Background....105
4.7.2 EOR Technologies....105
4.7.3 Lawrence Field....105
4.7.4 ASP Flood....107
4.7.5 Summary....108

CHAPTER 5- CONCLUSION....109

BIBLIOGRAPHY....110

List of Tables

Table 1: Predicted v/s actual performance for Field X main pays....61

Table 2: Reservoir Properties of Sand....62

Table 3: Permeability Data....63

Table 4: Composition of Field X Crude....64

Table 5: Variation in Oil Viscosity of Sand II....65

Table 6: Characteristics of Petroleum Sulphonates Used....66

Table 7: (I)Selection & Optimisation of Alkali Concentration....67

(II)Selection & Optimisation of Surfactant Concentration....67

(III)IFT Reduction Through Alkali-Surfactant Blends....68

Table 8: Results of ASP flood displacement experiments (Field X Sand S-II)....69

Table 9: Petrophysical Properties of the Pilot Wells....70

Table 10: (I)Pressure Data of the Pilot Wells....71

(II)Production Data of the Pilot Wells....71

Table 11: Injection Schedule- Inverted 5 Spot Pattern....72

Table 12: Sampling Schedule....73

Table 13: Cost Estimated of Sand II (Inverted 5-Spot Pattern)....74

Table 14: Operational and Chemical Costs....75

Table 15: Estimated Oil Recovery Against Fluid Injection: One Inverted Five Spot Pattern: Sand II....77

List of Figures

Figure 1.1- Recovery Methods....4

Figure 2.1- Why EOR is necessary....5

Figure 2.2-EOR Target for different hydrocarbons....6

Figure 2.3- Different Types of EOR Processes....6

Figure 2.4- Water flood patterns....10

Figure 2.5- Schematic of areal sweep in a uniform reservoir model for five spot....10

Figure 2.6- Areal sweep efficiency at water breakthrough for a five spot....11

Figure 2.7- Effect of mobility ratio on vertical sweep efficiency....11

Figure 2.8- Cyclic Steam Stimulation....17

Figure 2.9-SAGD Process....19

Figure 2.10-World Scenario of the use of chemical recovery methods....21

Figure 2.11-Surfactant Flood....22

Figure 2.12- Comparison of viscosities of two types of polymers at 1000 ppm in 1% NaCl at 74 Degree Fahrenheit....23

Figure 2.13-Idealised View of an ASP Flood....29

Figure 3.1-Generalised Statigraphy of the Pay Horizons....78

Figure 3.2- A Schematic View of the ASP Flood Process....79

Figure 3.3- Selection of Best Surfactant in Terms of IOR....80

Figure 3.4- Fraction of Inject Surfactant Conc. Eluted v/s Pore Volume Injected

Surfactant Adsorption : Contd. Slug....81

Figure 3.5- Fraction of Inject Alkali Conc. Eluted v/s Pore Volume Injected

Alkali Adsorption: Contd. Slug....82

Figure 3.6- Slug Size Optimisation....83

Figure 3.7- Fraction of Inject Alkali/Surfactant Conc. Eluted v/s Pore Volume Injected

Adsorption Study..84

Figure 3.8- Displacement Efficiency v/s PV Injected..85

Figure 3.9- Fraction of Inject Alkali/Surfactant Conc. Eluted v/s Pore Volume Injected

Adsorption Study at Tertiary Stage..86

Figure 3.10- Displacement Efficiency v/s Pore Volume Injected

Polymer Flooding At Secondary Stage...87

Figure 3.11- Displacement Efficiency v/s Pore Volume Injected

Comparative Displacement Efficiency...88

Figure 3.12- Capillary no. Correlation Method...89

Figure 3.13- Fractional Flow Curve (At Secondary Stage) 90

Figure 3.14- Fractional Flow Curve (At Tertiary Stage) 91

Figure 3.15- Performance Graph of Well no.-6...92

Figure 3.16- Performance Graph of Well no.-45...93

Figure 3.17- Performance Graph of Well no.-52...94

Figure 3.18- Performance Graph of Well no.-90...95

Figure 3.19- Performance Graph of Well no.-118...96

Figure 3.20- Flow Diagram of ASP Flooding Injection
Plant..97

Figure 3.21- ASP Case Study...98

Figure 4.1-FBX ASP pilot test results (central producing wells) 101

Figure 4.2- Lawrence Field showing the ASP pilot and Plains Illinois, Inc.'s holdings......................104

Figure 4.3- Core photo showing Cypress Sandstone interval 4(D). The Cypress Sandstone is the most porous and permable unit in Cypress. The core shows mottled iron staining. Rip-up clasts form permeablility barriers......106

Figure 4.4- The Pilot ASP flood pattern indicating close spacing of ASP and water injectors and producing wells......107

Figure 4.5- Decline curves at the Lawrence Field ASP pilot. Production had peaked and was in a steep decline following 96 years of primary and waterflood recovery. The projected ASP flood will increase ultimate recovery and extend reservoir life......108

Abbreviations

IOIP- Initial oil in place

EOR- Enhanced oil recovery

W/C- Water cut

GOR- Gas oil Ratio

IFT- Inter facial tension

SAGD- Steam assisted gravity drainage

Chapter 1-

Introduction-

The use of reservoir energy to produce oil and gas generally results in a recovery of less than 50% of the original oil in place. Secondary recovery techniques, in which external energy is added to a reservoir to improve the efficiency of the primary recovery mechanisms, have been in use for many years. The injection of water to supplement natural water influx has become an economical and predictable recovery method and is applied worldwide. Less commonly gas injection has been used to displace oil down dip in "attic" oil recovery projects or to maintain gas cap pressure. Still both primary and secondary recovery techniques have only been effective in producing one third of the oil produced. The processes developed to increase recovery from reservoirs considered depleted by primary mechanism and secondary methods of water or gas injection, were historically termed as tertiary recovery techniques. However, because some of these processes may be applied earlier in life of a reservoir , perhaps even in the first day of production , the "tertiary" term is no longer appropriate here, and as a result , the term enhanced oil recovery methods has been introduced as the term to be used for all processes that attempt to alter the physical forces that control the movement of oil within the reservoir.

Both conventional water and gas injection, and the more unconventional enhanced oil recovery methods can collectively be termed improved oil recovery methods.

The methods of primary and secondary recovery are as under-

1.1Primary Recovery

1.1.1Depletion Drive

- As the reservoir pressure decreases with production, gas dissolved in oil evolves and displaces oil.
- Reservoir energy to displace oil is due to fluid and rock compressibility.
- Recovery : 5-30%.

1.1.2Gas Cap Expansion

- Gas compressed in gas cap (if exists) expands as reservoir pressure declines.
- Pressure can be kept by gas injection.
- If water is injected oil displaced by water may trap the gas entrance from the gas cap

- Recovery: 20-40%

1.1.3WATER DRIVE

There may exist an aquifer near reservoir.

- Water compressed in the aquifer expands once the reservoir pressure decreases by production. .
- Recovery : 35-75%.

1.1.4 GRAVITY DRAINAGE

- In thick and well connected in vertical direction or inclined reservoirs, gas moves upward to replace the space left by oil. It is a rather slow process because gas is more mobile than oil and the mobility of oil controls the process.
- Recovery: 25-90%

1.2Secondary Recovery

Pressure Maintenance

Water

Gas

Water Flooding

- To maintain reservoir pressure
- To displace oil by increasing viscous forces

1.2.1Water Flooding-

Water Flooding is a secondary recovery process in which water is injected in reservoir to obtain additional oil recovery by displacement of reservoir oil to the producing well after the reservoir has approached its economic productive limit by primary recovery method. Water injection is the proven method for additional oil production from oil fields.

Thus water injection is performed:

-To maintain the reservoir pressure and thus the optimum energy of the fluids present in the reservoir.

-To displace the oil towards the producer well.

1.2.2 REQUIREMENT OF INJECTION WATER

-Low suspended solids.

-Compatible with formation fluids.

-Compatible with formation rock.

-Free from dissolved oxygen.

-Non corrosive and chemically stable.

-Free from harmful bacteria

1.2.3SOURCES OF WATER FOR INJECTION

-Effluent water

-Sea water (in off shore area)

-Fresh water from rivers, lakes and tube well etc.

-Mixture of two or more waters

1.2.4STUDIES REQUIRED FOR DESIGNING WATER FOR INJECTION:

-The first step in determining the suitability of any water for injection is to analyze the proposed injection water for physical, chemical and biological constituents because petroleum reservoir rocks behave like filters and are susceptible to plugging by any type of solid material which may be suspended in or precipitated from any injection fluid.

-The composition of formation water and mineralogy of the rock are to be studied because formation water and rocks may react with injection water and may cause injectivity problems. Clay such as smectite, kaolinite is sensitive to injection water. Permeability reduction may occur due to clay dispersion and clay swelling. To overcome these problems certain water quality tests are necessary to determine such variables as the amounts and composition of solids, compatibility of injection water with reservoir rock and fluids, degree of corrosion and scaling tendency and presence of harmful bacteria.

1.3 Tertiary Recovery/EOR Phase -

The tertiary recovery is also a supplementation of natural reservoir energy; however it is defined as that additional recovery over and above what could be recovered from primary and secondary recovery methods.

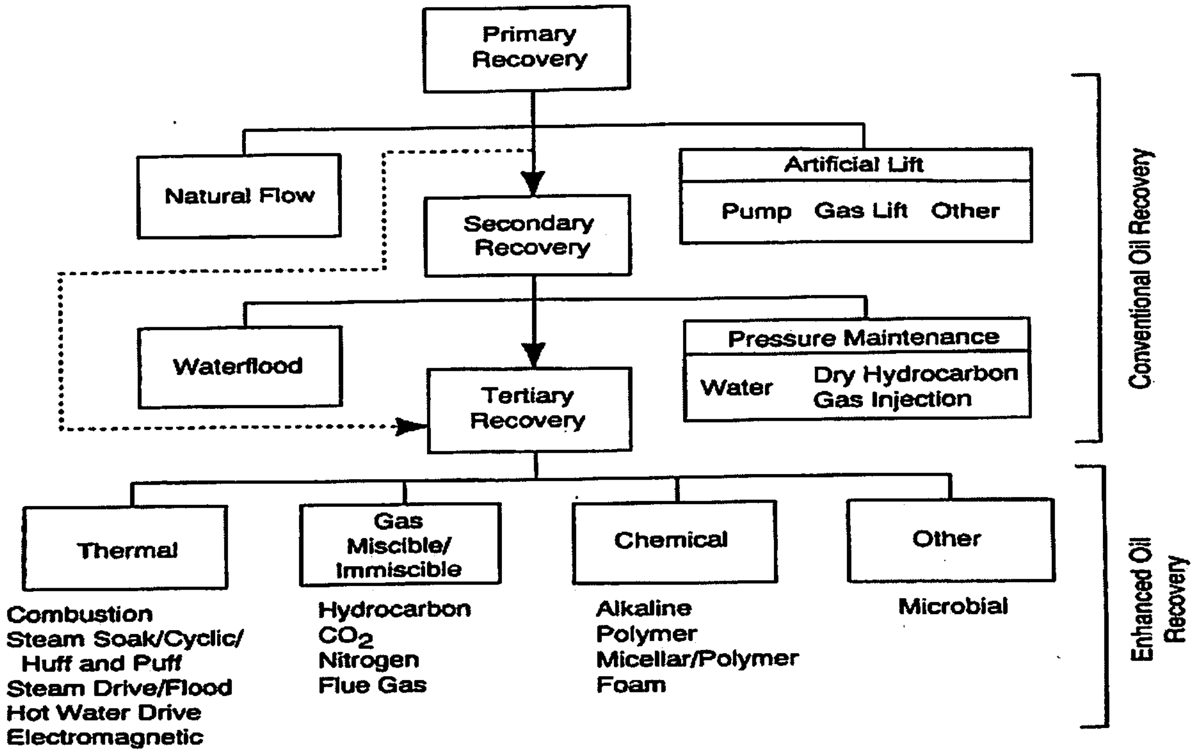


Figure 1.1- Recovery Methods

1.3.1 Concept Involved in the recovery processes-

*TO INCREASE EFFECTIVENESS OF OIL REMOVAL FROM PORE OF THE ROCK

*TO INCREASE THE VOLUME OF ROCK CONTACTED BY DISPLACING FLUID.

*REDUCE OR ELIMINATE THE CAPILLARY FORCES THAT TRAP THE OIL WITHIN THE PORES

*TO MINIMISE THE EFFECT OF GRAVITY FORCES

*TO REDUCE THE VISCICITY OF OIL SO AS TO IMPROVE THE MOBILITY

Chapter 2 – EOR (VARIOUS PROCESSES)

2.1What is Enhanced Oil Recovery-

Enhanced Oil Recovery, or "EOR," is the use of any process or technology that enhances the displacement of oil from the reservoir, other than primary recovery methods. Enhanced Oil Recovery methods and technologies' enhancements or improvements of the primary recovery methods are also known as secondary recovery methods and may be utilized in the recovery of oil at any stage of production. Enhanced oil recovery method refers to any recovery method other than primary and the conventional secondary recovery methods through "flooding" (water or fire) or through injecting steam or gas such as nitrogen or carbon dioxide. All tertiary recovery methods are enhanced, but not all enhanced methods are tertiary.

2.2 Why EOR-

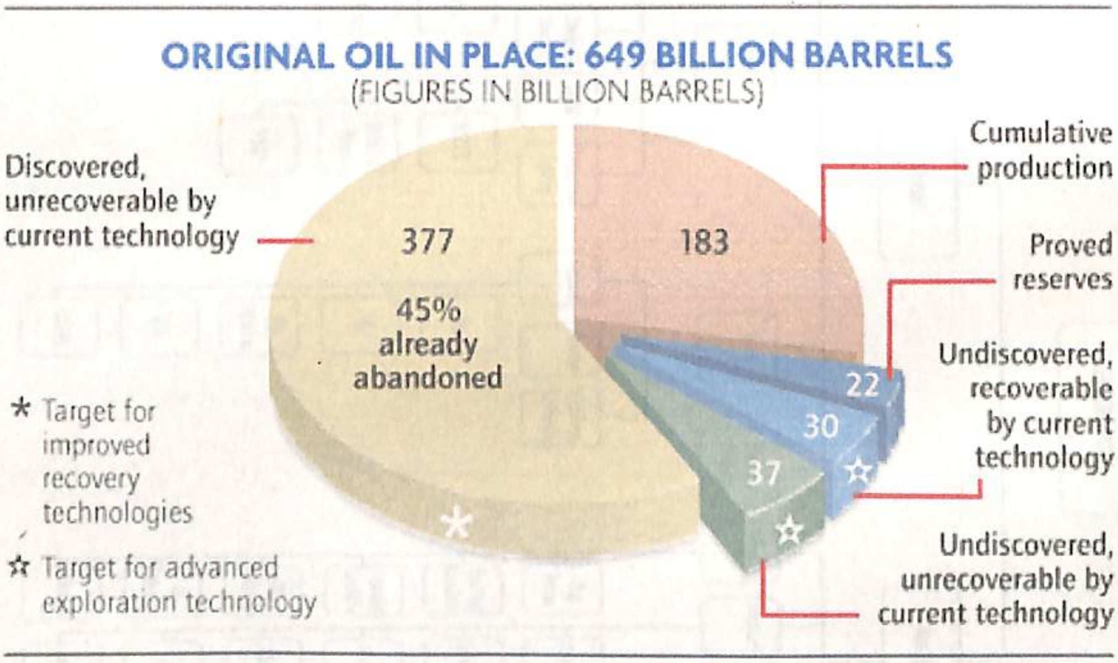


Figure 2.1- Why EOR is necessary

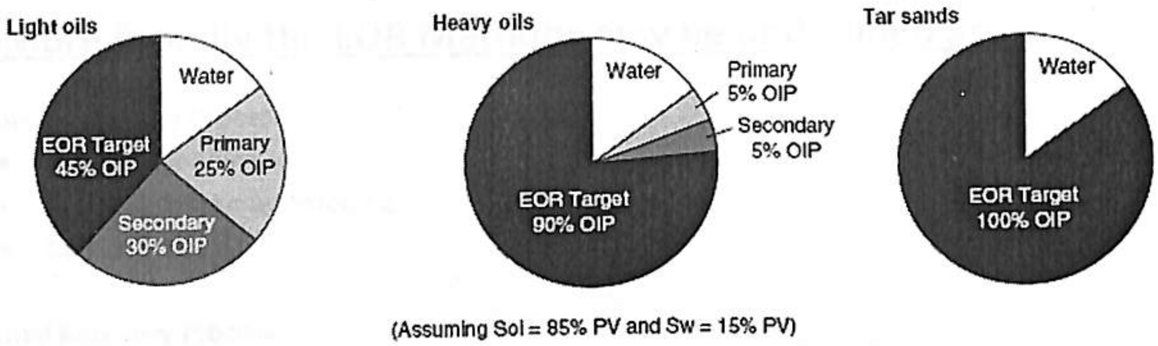
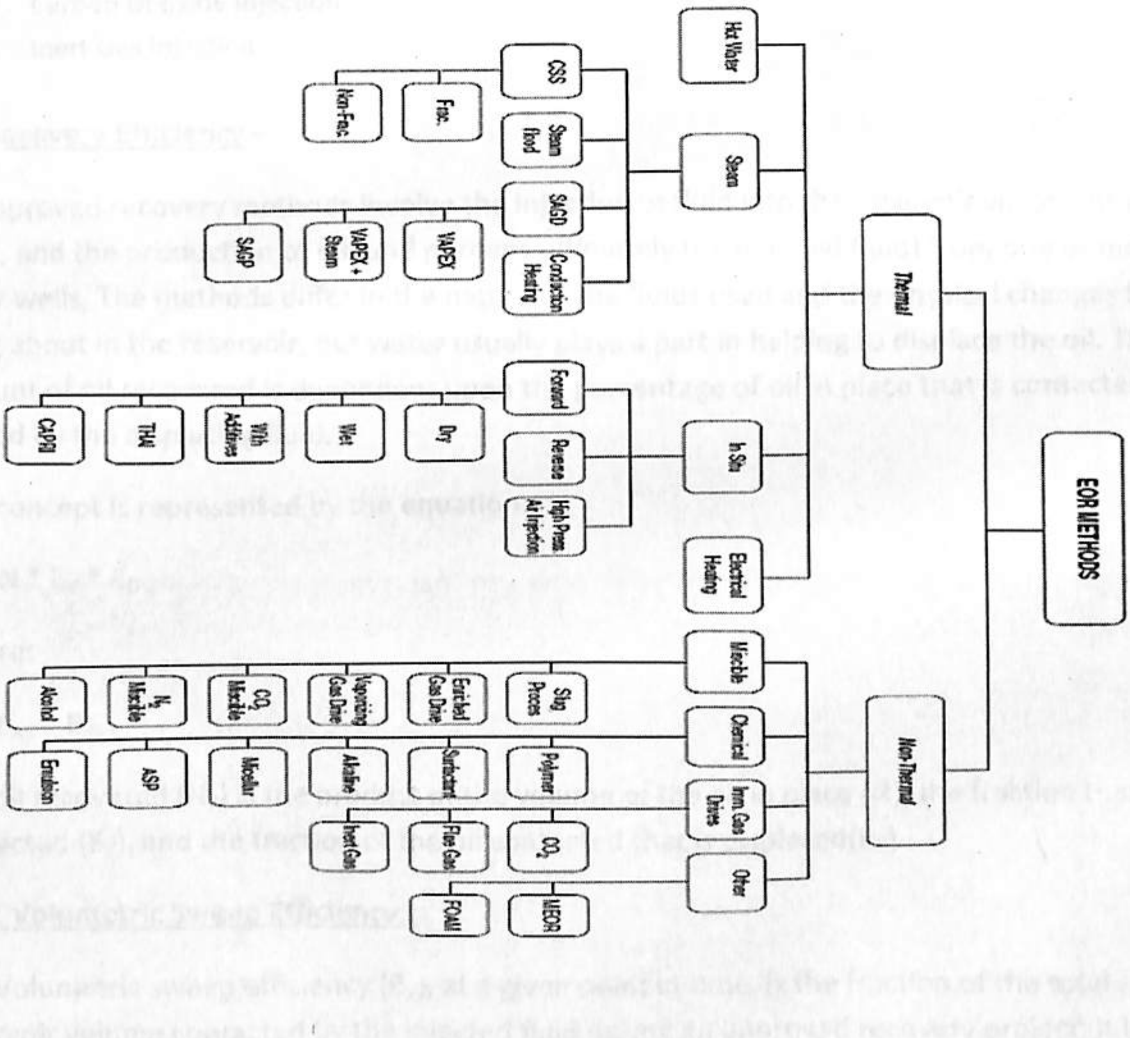


Figure 2.2-EOR Target for different hydrocarbons

Figure 2.3- Different Types of EOR Processes-



2.2More Broadly the EOR Methods may be underlined as-

Chemical Recovery Process

- Polymer Flooding
- Surfactant Polymer Flooding
- Caustic Flooding

Thermal Recovery Process

- Steam Flooding
- In Situ Combustion

Miscible Recovery Process

- Miscible Hydrocarbon Displacement
- Carbon Di-oxide Injection
- Inert Gas Injection

2.3 Recovery Efficiency –

All improved recovery methods involve the injection of fluid into the reservoir via one or more wells, and the production of oil (and perhaps ultimately the injected fluid) from one or more other wells. The methods differ in the nature of the fluids used and the physical changes they bring about in the reservoir, but water usually plays a part in helping to displace the oil. The amount of oil recovered is dependent upon the percentage of oil in place that is contacted and moved by the displacing fluid.

This concept is represented by the equation:

$N_P = N * E_V * E_D$

Where:

$E_V = E_{AS} * E_{VS}$.

The oil recovered (N_P) is the product of the volume of the oil in place (N), the fraction that is contacted (E_V), and the fraction of the oil contacted that is displaced(E_D).

2.3.1 Volumetric Sweep Efficiency:

The Volumetric sweep efficiency (E_V), at a given point in time, is the fraction of the total reservoir volume contacted by the injected fluid during an improved recovery project. It is composite of the areal sweep efficiency (E_{AS}),and the vertical sweep efficiency(E_{VS}).The areal sweep of water through an oil reservoir depends upon where the water is injected relative to where the oil is produced. It should also be pointed out that areal variations in permeability will have a major effect on the ability of the displacing phase to sweep the reservoir. Vertical sweep efficiency (EVS) also depends upon the mobility ratio and, in addition, on the vertical distribution of permeability within the reservoir.

2.3.2 Displacement Efficiency.

The displacement efficiency refers to the fraction of the oil in place that is swept from a unit volume of the reservoir. displacement efficiency is a function of fluid viscosities and the relative permeability characteristics of the reservoir rock (mobility ratio), of the "wettability" of the rock, and of pore geometry.

The relative permeability characteristics of a reservoir rock and the fluid viscosities are the properties used to determine the displacement efficiency. the relative permeability reflects the composite effect of pore geometry, wettability ,fluid distribution and saturation history on the fluid flow behavior of the rock – fluid system.The displacement efficiency for a waterflood can be calculated using the fluid viscosities and the water-oil relative permeability characterstics.

2.3.3 Efficiency due to conformance

This depends onFluid –Rock Properties like

- Wettability
- Ion Exchange capacity if Media
- Capability of adsorption
- Other lithological parameters

The value of this factor varies from zero to one.

2.4 Mobility and Mobility Ratio-

When oil is swept from a reservoir by water, an important factor in determining the areal and vertical sweep efficiencies is the difference in the mobilities of the two fluids. The mobility of any fluid in a porous medium such as reservoir rock is directly proportioned to its velocity of flow and is equal to the effective permeability to that fluid divided by the fluid viscosity . For oil this would be equal to k_o/μ_o. Because our reservoir permeability information is available in terms of relative permeability , the mobility is expressed as:

$\lambda = (k_{ro})k/\mu_o$

The mobility ratio is defined as the mobility of the displacing phase in the portion of the reservoir contacted by the injected fluid, divided by the mobility of the displaced phase in the non invaded portion of the reservoir . In the case of water displacing oil (water flooding):

$M_{wo} = [(k_{rw})*k*\mu_o] / [(k_{ro})*k*\mu_w]=(k_{rw}* \mu_o)/(kro* \mu_w)$

If M is less than or equal to one, it means that the oil is capable of travelling at the same or greater velocity than the water, under the same conditions. The water, therefore , will not bypass the oil and will instead push it ahead. If M is greater than one, the water is capable of moving faster than the oil and will bypass some of the oil , leaving unswept areas behind. An increase in the viscosity of the oil will cause the mobility ratio to increase. This is logical, as one can imagine attempting to push a viscous, heavy oil through a pore system and having the less viscous water "finger" through or around the slow moving oil. An obvious approach to improving the mobility ratio would be to decrease the difference in oil and water viscosities , by increasing the water viscosity and/or decreasing the oil viscosity.

The areal sweep of water through an oil reservoir depends upon where the water through an oil reservoir depends upon where the water is injected relative to where the oil is produced. A wide variety of flooding patterns have been used in the oil field and some of these are reproduced as in figure 2.4. Laboratory models have enabled researchers to measure to measure the areal sweep efficiencies for different mobility ratio flood pattern combinations. For example , if wells are spaced in a five-spot pattern and are producing from a homogeneous uniform reservoir , the areal sweep efficiency at the point in time when the displacing phase breaks through to the producing well has shown to be about 68% to 72% for a mobility ratio of 1.0. Figure 2.5 shows, in stages, the sweep of a five spot model as the injected fluid moves to breakthrough. Figure 2.6shows how the areal sweep efficiency at breakthrough for this pattern changes with the mobility ratio. Sweep efficiency at the breakthrough is important because, generally, little additional oil is recovered by injecting water after a channel of water flow exists between injector and producer.

It should also be pointed out that areal variations in permeability will have a major effect on the ability of the displacing phase to sweep the reservoir. For this reason, the reservoir engineer now works closely with the development geologist to define the reservoir environment.

Vertical sweep efficiency (E_{VS}) also depends upon the mobility ratio and, in addition, on the vertical distribution of permeability within the reservoir. The laboratory determined areal sweep efficiencies mentioned assume a homogeneous reservoir. If the permeability varies vertically, as in often the case in a real reservoir, an injected fluid will move through the reservoir with an irregular vertical front, moving more rapidly in the more permeable sections. The sweep efficiency at breakthrough will depend on the degree of difference in permeabilities and on the mobility ratio. Figure 2.7 shows how changes in the mobility ratio is greater than 1.0, the displacing phase has more mobility than the displaced phase. Thus, as displacing fluid enters the high permeability zone, the total resistance to flow decreases in that zone and the flow in that zone increases. When breakthrough eventually occurs, a greater portion of the lower permeability zone is unswept . When M is less than 1.0, the channeling effect is less pronounced.

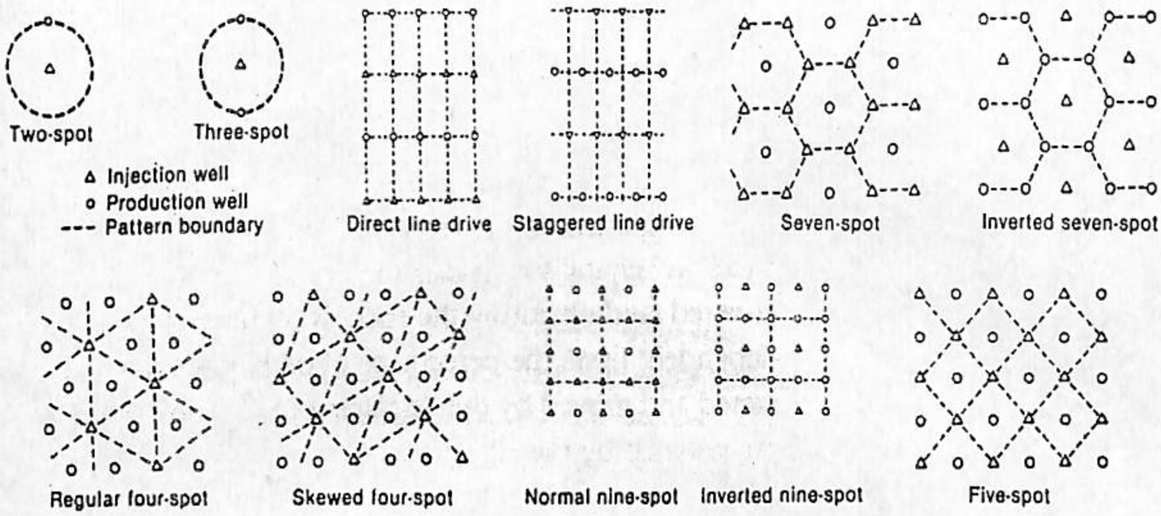


Figure 2.4- Water flood patterns

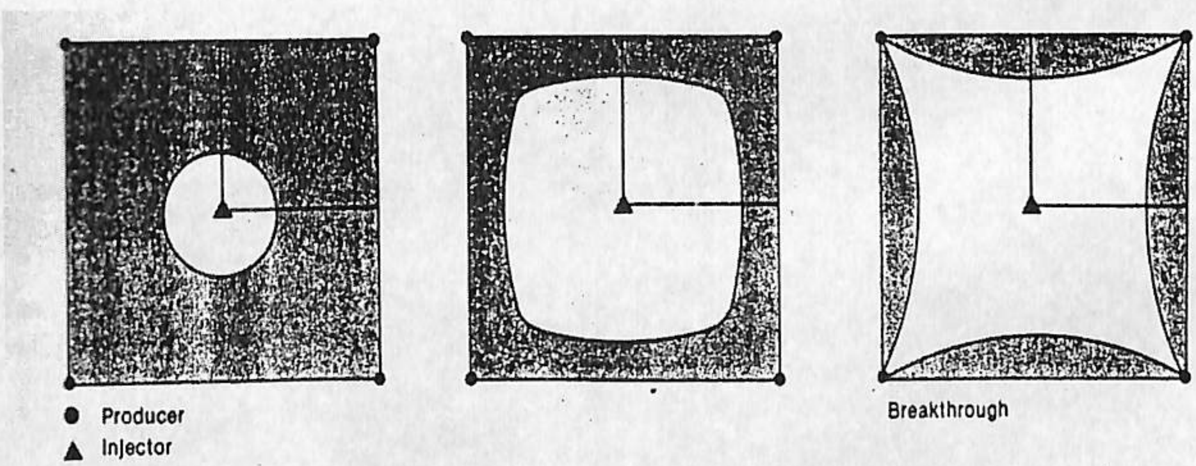


Figure 2.5- Schematic of areal sweep in a uniform reservoir model for five spot pattern(M=1)

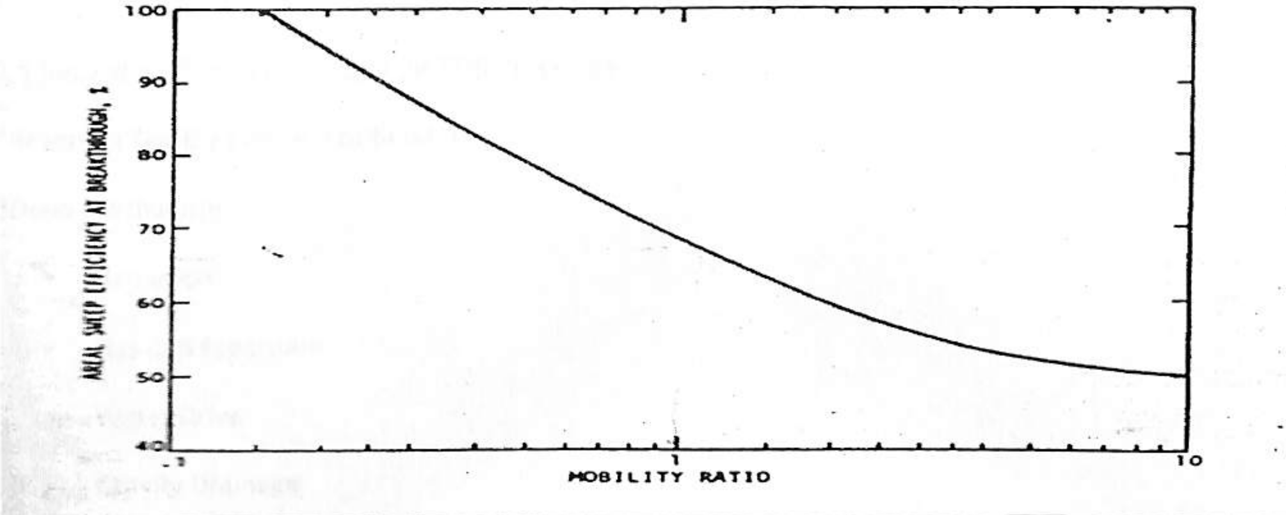


Figure 2.6- Areal sweep efficiency at water breakthrough for a five spot pattern

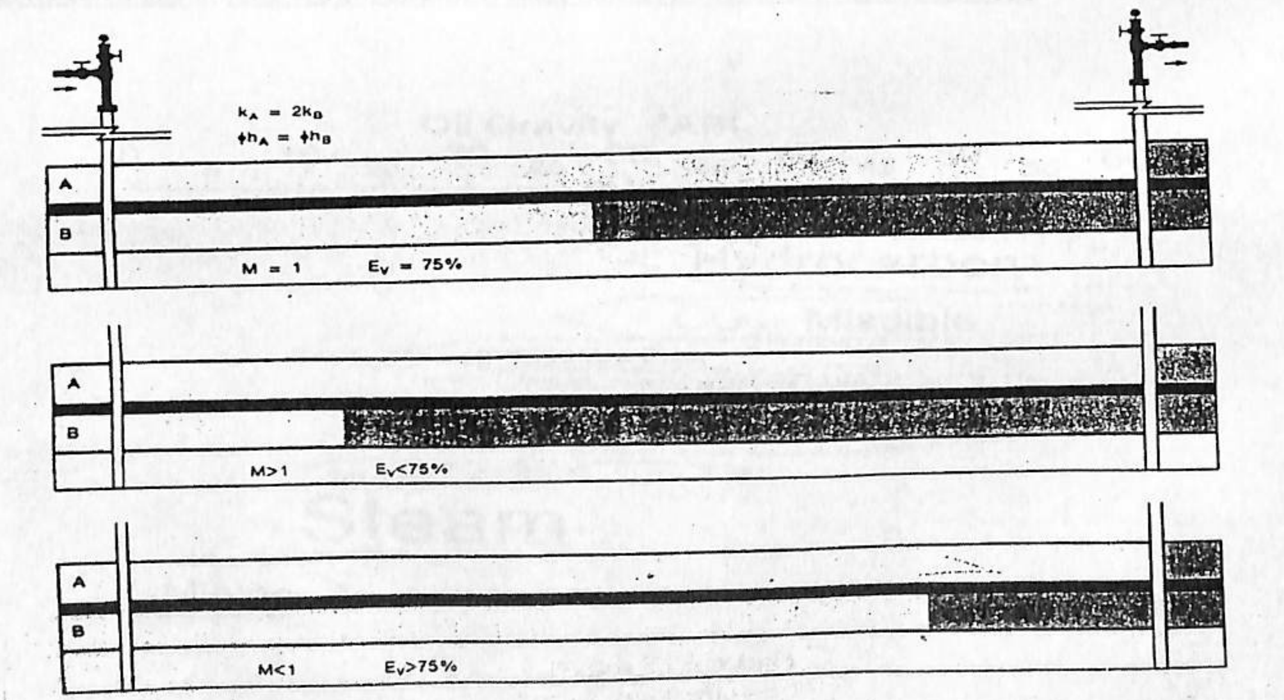


Figure 2.7- Effect of mobility ratio on vertical sweep efficiency

2.5 Recovery Efficiency (Factors) for EOR Processes-

*Reservoir Quality (Phi, K, continuity)

*Drive Mechanism

- Depletion
- Gas Cap Expansion
- Water Drive
- Gravity Drainage
- Combination

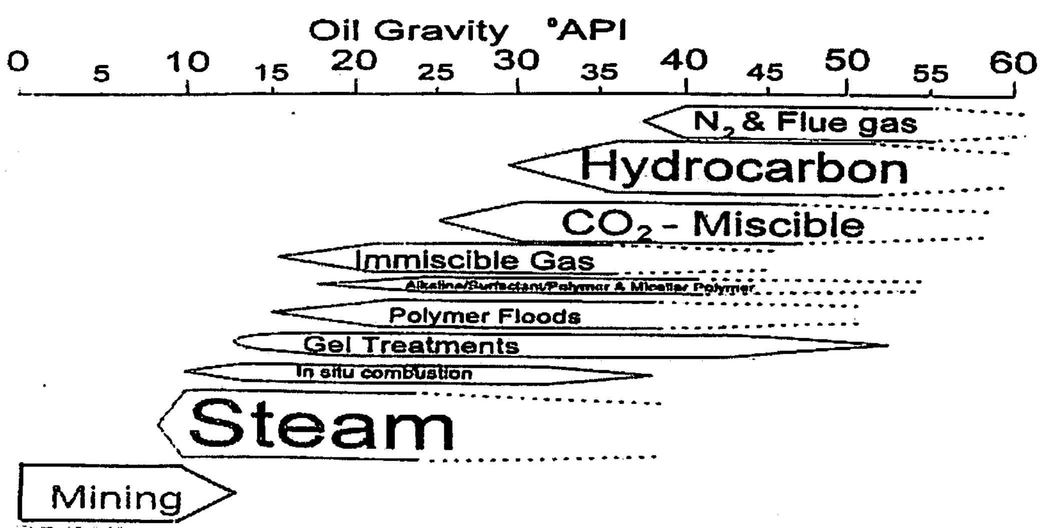
*Well spacing

*Time

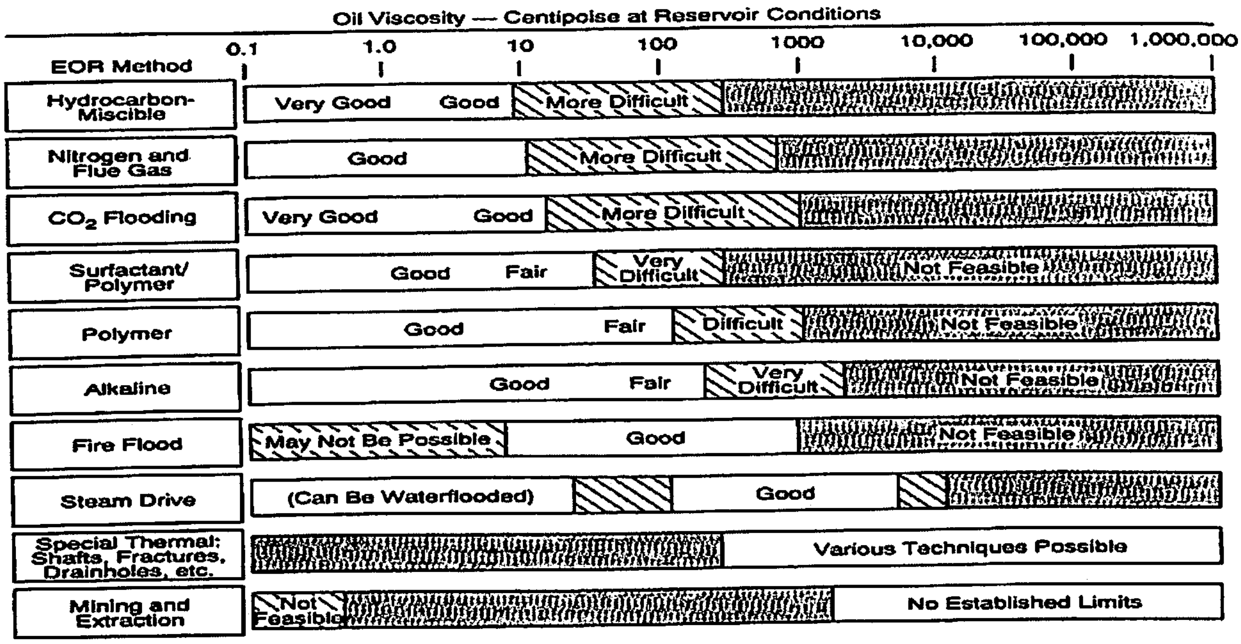
*Type Of Fluids (Gas, Oil, Heavy Oil, Tar)

2.6 Screening Criteria of Various EOR Processes

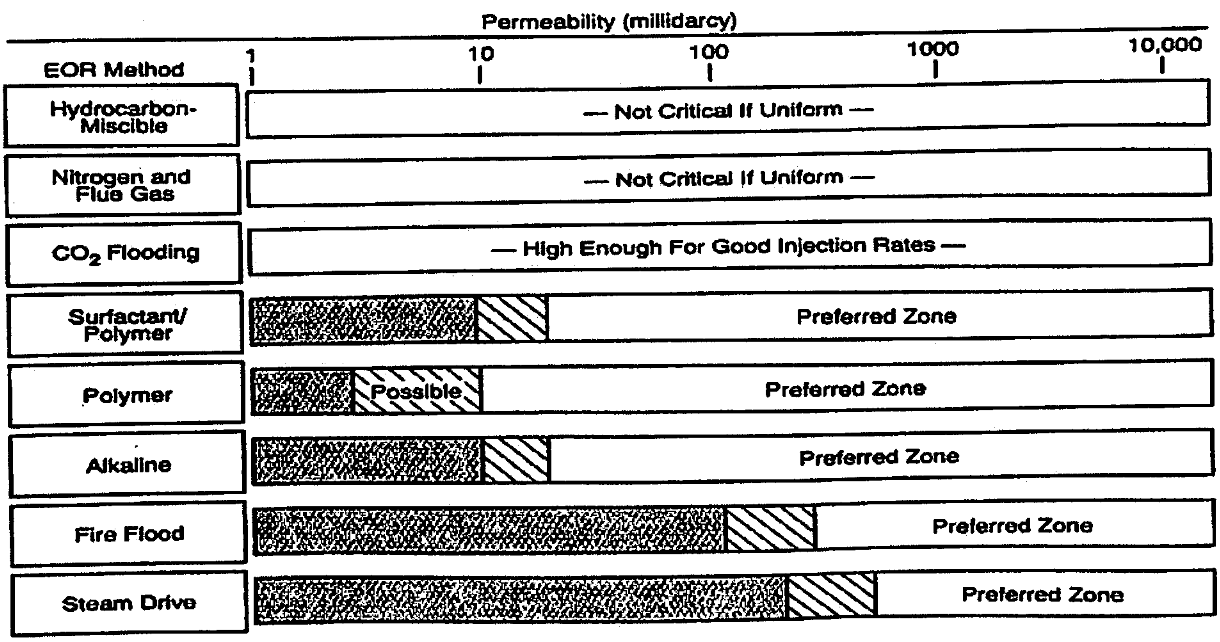
2.6.1 Screening Criteria of Various EOR Processes(Based on API Gravity of Crude Oil)-



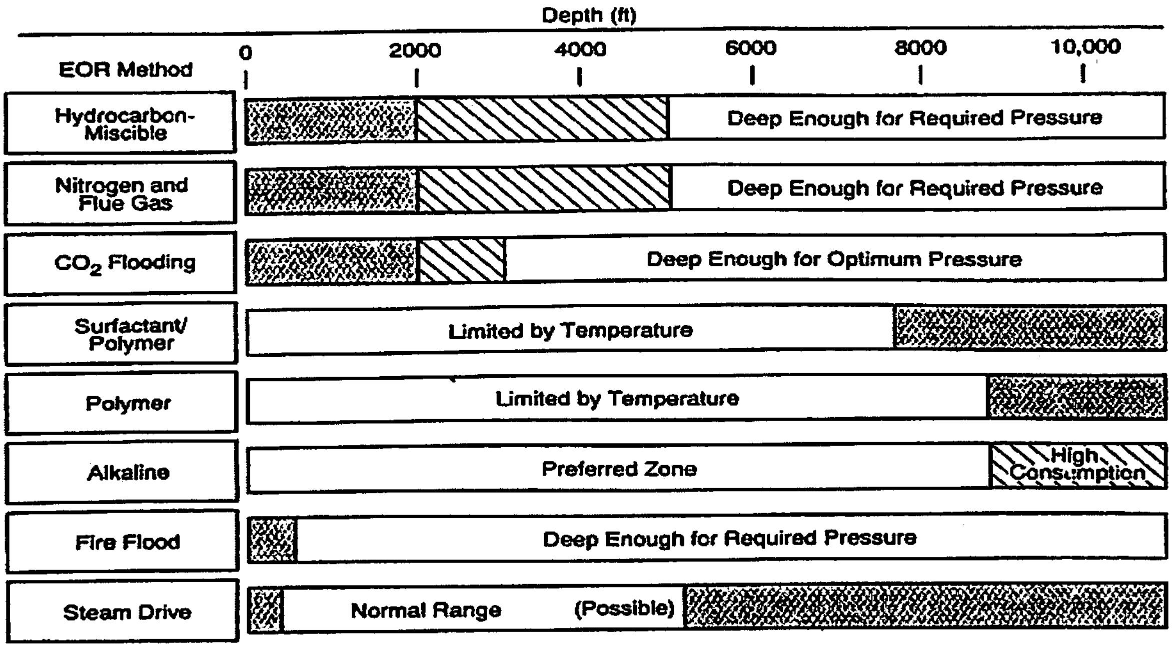
2.6.2 PREFERRED OIL VISCOSITY RANGES FOR ENHANCED RECOVERY METHODS



2.6.3 PERMEABILITY GUIDES FOR ENHANCED RECOVERY METHODS



2.6.4 DEPTH LIMITATION FOR ENHANCED OIL RECOVERY METHODS



2.7 Miscible Flooding Method-

Miscible flooding implies that the displacing fluid is miscible with the reservoir oil either at first contact (SCM) or after multiple contacts (MCM). A narrow transition zone (mixing zone) develops between the displacing fluid and the reservoir oil, inducing a piston-like displacement. The mixing zone and the solvent profile spread as the flood advances. The change in concentration profile of the displacing fluid with time is shown in Figure. Interfacial tension is reducedto zero in miscible flooding, therefore, $Nc = \infty$. Displacement efficiency approaches 1 if the mobility ratio is favourable ($M < 1$). The various miscible flooding methods include:

– miscible slug process,
– enriched gas drive,
– vaporizing gas drive,
– high pressure gas (CO_2 or N_2) injection

2.7.1 Miscible Slug Process

It is an SCM (single contact miscible) type process, where a solvent, such as propane or pentane, is injected in a slug form (4-5% HCPV). The miscible slug is driven using a gas such as methane or nitrogen, or water. This method is applicable to sandstone, carbonate or reef-type reservoirs, but is best suited for reef-type reservoirs. Gravity segregation is the inherent problem in miscible flooding. Viscous instabilities can be dominant, and displacement efficiency can be poor. Reef-type reservoirs can afford vertical gravity stabilized floods, which can give recoveries as high as 90% OOIP. Several such floods have been highly successful in Alberta, Canada. Availability of solvent and reservoir geology are the deciding factors in the feasibility of the process. Hydrate formation and asphaltene precipitation can be problematic.

2.7.2 Enriched Gas Drive

This is an MCM type process, and involves the continuous injection of a gas such as natural gas, flue gas or nitrogen, enriched with C2-C4 fractions. At moderately high pressures (8-12 MPa), these fractions condense into the reservoir oil and develop a transition zone. Miscibility is achieved after multiple contacts between the injected gas and the reservoir oil. Increase in oil phase volume and reduction in viscosity contrast can also be contributing mechanisms towards enhanced recovery. The process is limited to deep reservoirs (>6000 ft) because of the pressure requirement for miscibility.

2.7.3 Vaporizing Gas Drive

This also is an MCM type process, and involves the continuous injection of natural gas, flue gas or nitrogen under high pressure (10-15 MPa). Under these conditions, the C2-C6 fractions are vaporized from the oil into the injected gas. A transition zone develops and miscibility is achieved after multiple contacts. A limiting condition is that the oil must have sufficiently high C2-C6 fractions to develop miscibility. Also, the injection pressure must be lower than the reservoir saturation pressure to allow vaporization of the fractions. Applicability is limited to reservoirs that can withstand high pressures.

2.7.4 CO_2 Miscible

Carbon injection for improved recovery has been applied since the early 1970s in many oil fields on land. Output from large natural carbon sources is piped to the relevant oil fields for injection. Some industrial sources in the region also contribute carbon deliveries.

Injected carbon injection has an efficient sweeping effect in the reservoir, caused by:

- gas-oil miscibility
- compositional effect (swelling and vaporisation)
- reduced oil viscosity
- high density of carbon dioxide compared with oil
- high viscosity of carbon dioxide compared with hydrocarbon gas.

CO2 Miscible method has been gaining prominence in recent years, partly due to the possibility of CO2 sequestration. Apart from environmental objectives, CO2 is a unique displacing agent, because it has relatively low minimum miscibility pressures (MMP) with a wide range of crude oils. CO2 extracts heavier fractions (C5-C30) from the reservoir oil and develops miscibility after multiple contacts. The process is applicable to light and medium light oils (>30° API) in shallow reservoirs at low temperatures. CO_2 requirement is of the order of 500-1500 sm3/sm3 oil, depending on the reservoir and oil characteristics. Many injection schemes are in use for this method. Particularly notable among them is the WAG (Water Alternating Gas) process, were water and CO_2 are alternated in small slugs, until the required CO_2 slug size is reached (about 20% HCPV). This approach tends to reduce the viscous instabilities. Cost and availability and the necessary infrastructure of CO_2 are therefore major factors in the feasibility of the process. Asphaltene precipitation can be a problem in some cases. Currently there are 80 CO_2 floods in North America.

Present position offshore-

So far no application based on carbon injection for offshore IOR has been initiated. Reservoir evaluation and screening studies for offshore carbon injection have been carried out on several Norwegian fields. A lack of readily available carbon sources and the high costs of carbon capture and transport have so far meant that carbon injection into fields on the Norwegian continental shelf would be uneconomic at low to medium oil prices. However, this picture may change in future if cheaper carbon dioxide becomes available for injection – through governmental incentives or reduced costs – and a rise in long-term oil prices.

Challenges-

Special challenges are posed for the offshore use of carbon dioxide by materials corrosion, facilities and excessive well spacing. The use of carbon dioxide in water-alternating-gas (WAG) injection seems to be the most promising option as a tertiary recovery method for fields where the current production strategy is water flooding. Big uncertainties also exist in estimates, while large variations in predictions for IOR from different fields reflect individual reservoir properties and field conditions. The simulation of a carbon dioxide WAG process faces similar challenges to a hydrocarbon WAG.

2.7.5 N_2 Miscible

This process is similar to CO_2 miscible process in principle and mechanisms involved to achieve miscibility, however, N_2 has high MMP with most reservoir oils. This method is applicable to light and medium light oils (>30° API), in deep reservoirs with moderate temperatures. Cantarell N_2 flood project in Mexico is the largest of its kind at present, and is currently producing about 500 000 B/D of incremental oil.

2.8 Thermal EOR Methods-

Thermal EOR entails introducing heat into the reservoir in a controlled manner to reduce oil viscosity. This method typically targets highly viscous, or heavy, crude oils. Because heavy oil is such an important

component of the U.S. oil resource base, yet h
area to it—including "cold" recovery methods

Heavy oil is recovered by introducing heat into
Steam flooding and in situ combustion or air in
methods. Steam flooding is used extensively in
cold production and sand injection and horizor
mainly in Canada and Venezuela, which have e
by injecting steam into reservoirs that are rela
moderately viscous oil. The dominant mechani
viscosity of the oil, allowing flow to the wellbo
distribution are being overcome. Steam floodi

In situ combustion introduces heat in the reser
burn portions of the oil to displace additional c
through continuous injection of air into the res
contributes to operational problems. Both stea
facility costs and require special safety measur

2.8.1 Cyclic Steam Injection-

Cyclic steam stimulation [is a "single well" proc
In the initial stage, steam injection is continue
days for heat distribution, denoted by soak. Fo
increases quickly to a high rate, and stays at th
months. Cycles are repeated when the oil rate
lower, and it increases as the number of cycles
heat distribution as well as capture of the mob
payout, however, recovery factors are low (10-
pressure. The process becomes more complex

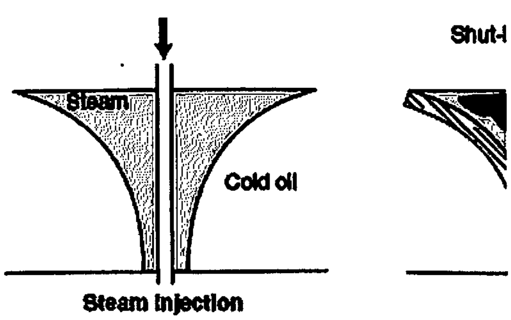


Figure 2.8- (

2.8.2 Steam Flooding-

Steam flooding is a pattern drive, similar to water flooding, and performance depends highly on pattern size and geology. Steam is injected continuously, and it forms a steam zone which advances slowly. Oil is mobilized due to viscosity reduction. Oil saturation in the swept zone can be as low as 10%. Typical recovery factors are in the range 50-60% OIP. Steam override and excessive heat loss can be problematic.

2.8.3 Steam Assisted Gravity Drainage (SAGD)-

SAGD was developed for the in situ recovery of the Alberta bitumen. The process relies on the gravity segregation of steam, utilizing a pair of parallel horizontal wells, placed 5 m apart (in the case of tar sands) in the same vertical plane. The schematic is shown in Figure 2.9. The top well is the steam injector, and the bottom well serves as the producer. Steam rises to the top of the formation, forming a steam chamber. High reduction in viscosity mobilizes the bitumen, which drains down by gravity and is captured by the producer placed near the bottom of the reservoir. Continuous injection of steam causes the steam chamber to expand and spread laterally in the reservoir. High vertical permeability is crucial for the success of SAGD. The process performs better with bitumen and oils with low mobility, which is essential for the formation of a steam chamber, and not steam channels. SAGD has been more effective in Alberta than in California and Venezuela for the same reason. SAGD is highly energy intensive. Large volumes of water are required for steam generation, and the natural gas consumption for steam generation ranges between 200- 500 tonnes/sm^3 of bitumen. There had been several attempts to improve the economics of SAGD. Notable examples among SAGD variations are VAPEX, ES-SAGD, and SAGP.

SAGD Variations

VAPEX is the non-thermal counterpart of SAGD, and it works on the same principles as SAGD. Instead of steam, a solvent gas, or a mixture of solvents, such as ethane, propane and butane is injected along with a carrier gas such as N_2 or CO_2. Solvent selection is based upon the reservoir pressure and temperature. The solvent gas is injected at its dew point. The carrier gas is intended to raise the dew point of the solvent vapour so that it remains in the vapour phase at the reservoir pressure. A vapour chamber is formed and it propagates laterally. The main mechanism is viscosity reduction. The process relies on molecular diffusion and mechanical dispersion for the transfer of solvent to the bitumen for viscosity reduction. Dispersion and diffusion are inherently slow, and therefore, are much less efficient than heat for viscosity reduction.

ES-SAGD

This process (Expanding Solvent SAGD) is another variation, where the addition of about 10% steam to the solvent mixture has been suggested to gain a 25% gain in the energy efficiency of VAPEX.

SAGP

Steam and Gas Push is also a variation, where a non condensable gas such as natural gas or nitrogen, is injected with steam to reduce the high demand of steam in SAGD. These processes are in the early stages of development, and are not proven on a commercial scale.

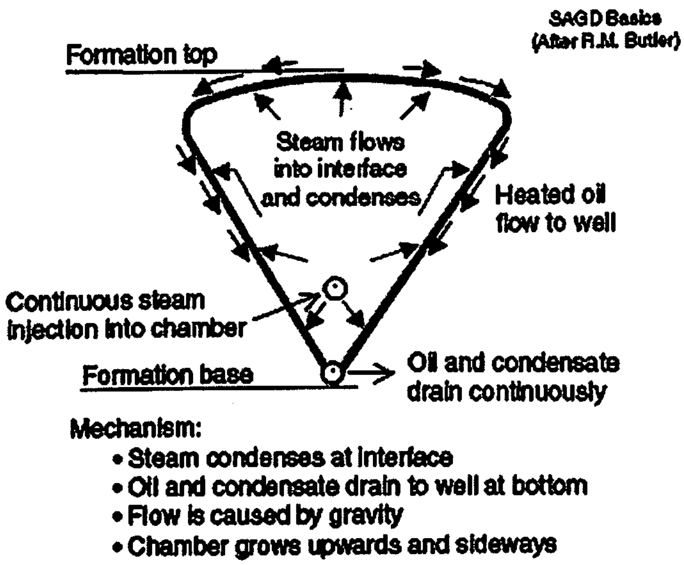


Figure 2.9-SAGD Process

2.8.4 In Situ Combustion-

In this method, also known as fire flooding air or oxygen is injected to burn a portion (~10%) of the in-place oil to generate heat. Very high temperatures, in the range of 450-600°C, are generated in a narrow zone. High reduction in oil viscosity occurs near the combustion zone. The process has high thermal efficiency, since there is relatively small heat loss to the overburden or underburden, and no surface or wellbore heat loss. In some cases, additives such as water or a gas is used along with air, mainly to enhance heat recovery. Severe corrosion, toxic gas production and gravity override are common problems. *In situ* combustion has been tested in many places, however, very few projects have been economical and none has advanced to commercial scale.

The main variations of in situ combustion are:

– Forward combustion,

– Reverse combustion,

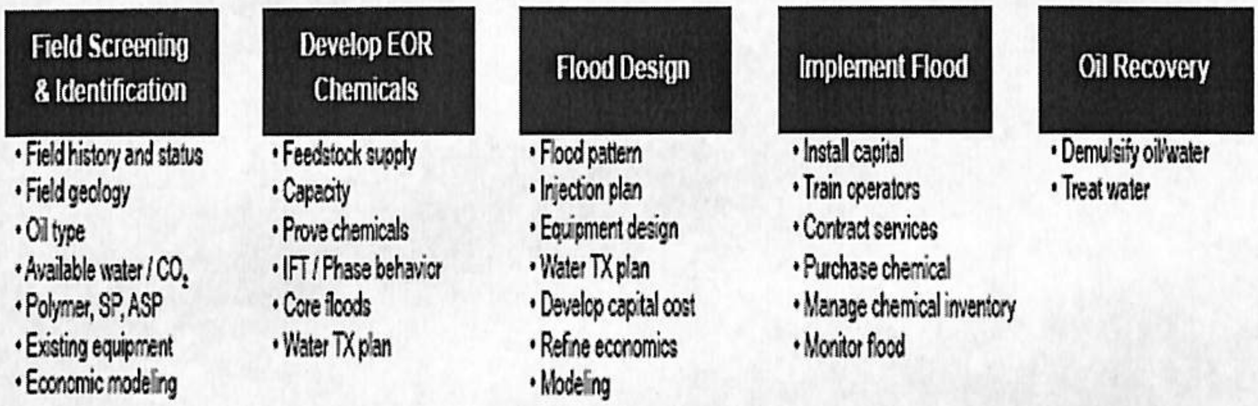
– High pressure air injection.

In forward combustion, ignition occurs near the injection well, and the hot zone moves in the direction of the air flow, whereas in reverse combustion, ignition occurs near the production well, and the heated zone moves in the direction counter to the air flow. Reverse combustion has not been successful in the field because of the consumption of oxygen in the air before it reaches the production well. High pressure air injection involves low temperature oxidation of the in place oil. There is no ignition. The process is being tested in several light oil reservoirs in the USA.

2.9 Chemical Flooding Methods-

Chemical EOR entails injecting chemicals either to reduce interfacial tension between the in-place crude oil and injected water, allowing the oil to be produced, or injecting other chemicals that can shut off excess water production, thus improving the "sweep" of a reservoir.

The various aspects of implementation of a chemical EOR project is summarized below-



Chemical EOR methods utilize:

-Polymers

-Surfactants

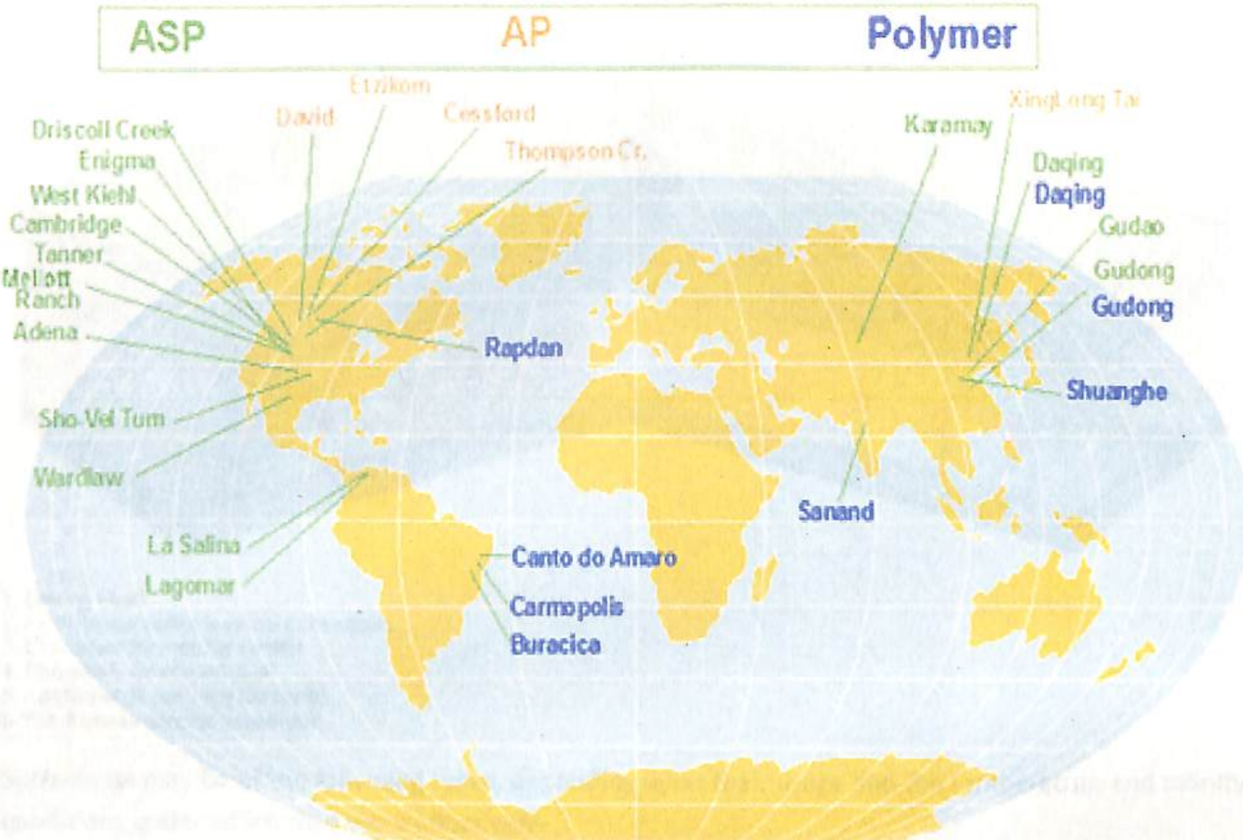
-Alkaline agents

-Combinations of such chemicals

-ASP (Alkali-Surfactant-Polymer) flooding

-MP (Micellar-Polymer) flooding

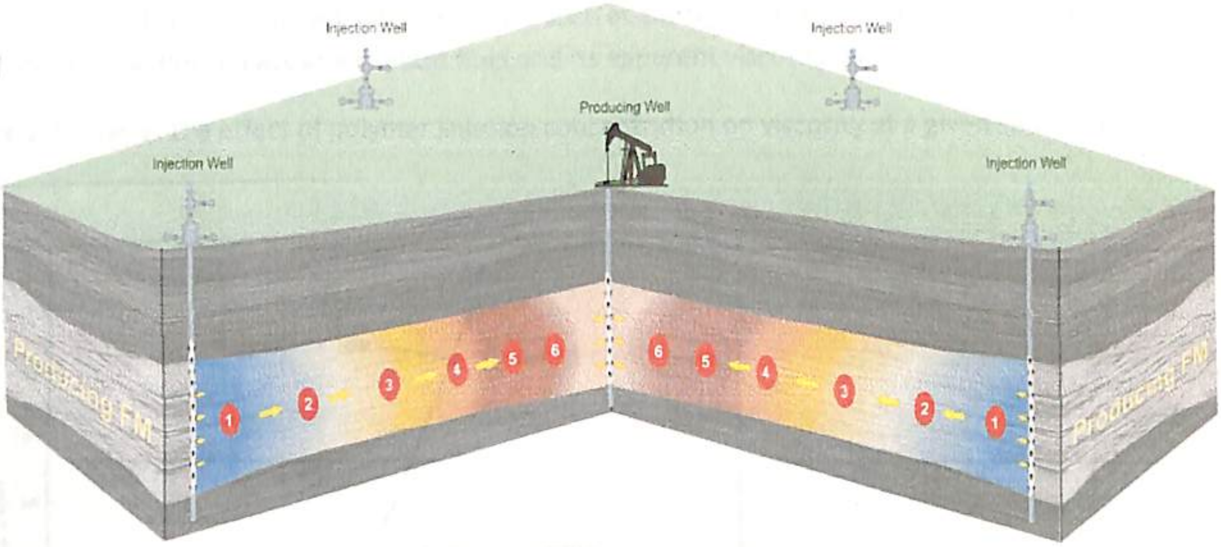
Figure 2.10-World Scenario of the use of chemical recovery methods-



2.9.1 Surfactants and Surfactant assisted water flood-

Surfactant Assisted Water Floods are employed in low permeability reseviors (0.1 - 100 mD) where it is difficult to inject water. This process can also be employed as a tertiary recovery method where conditions are such that polymer and/or alkali cannot be introduced into the reservoir. This could be the case where the permeability is too low, the temperature is too high, or the salinity is too high to include polymer. This process can also be used where the amount of divalent cations is too high to use alkali. A Surfactant Assisted Water Flood increases oil recovery by increasing injectivity and lowering interfacial surface tension.

Figure 2.11-Surfactant Flood



1. Driving Fluid
2. Fresh water buffer to protect chemicals
3. Chemicals for mobility control
4. Chemicals for releasing oil
5. Additional oil recovery (oil bank)
6. Pre-fl ush to condition reservoir

Surfactants may be of the following types, depending upon their usage and the temperature and salinity conditions under which they work effectively-

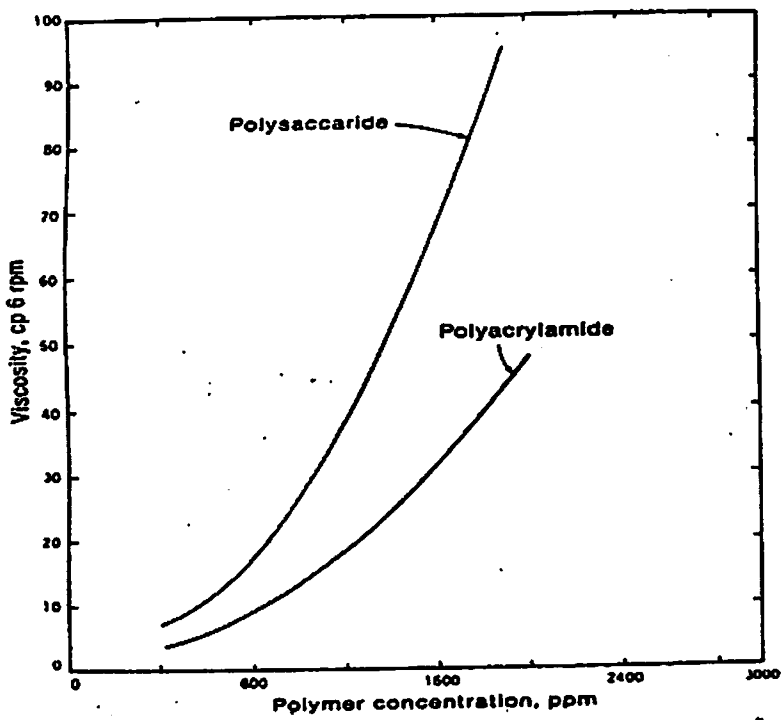
- Anionic
- Cationic
- Non ionic
- Zwitterionic- Amphoteric

The basic structure of a surfactant has a hydrophilic head and a hydrophobic tail. Surfactant are either used to stabilize the emulsion or to break it depending upon the use. Hence, its quantity is determined to.

2.9.2 Polymer-

An obvious approach to improving the mobility ratio would be to increase the effective viscosity of the injected water before injection into the reservoir. This can be done by the addition of long chain molecules, called polymers (the jelly like component in your tube of shampoo). Although there are many polymers available for this approach, the most economically attractive examples are polysaccharides (xanthum gum) and polyacrylamides. The polysaccharides are produced by microbial action while the polyacrylamides are synthetically produced chemicals with a wide range of molecular weights and chain lengths. Polysaccharides are relatively economical and stable, but are prone to bacterial and thermal degradation. A commercial polymer solution is a non-newtonian fluid. Its behavior is generally characterized as pseudoplastic; that is, its resistance to flow and its apparent viscosity are lower at low-flow velocities. However, at very high velocities, such as those that may exist near the injection wells, the polymer solution can act as a dilatant fluid and its apparent viscosity will increase.

Figure 2.12 shows the effect of polymer solution concentration on viscosity at a given shear rate.



<u>Figure 2.12- Comparison of viscosities of two types of polymers at 1000 ppm in 1% NaCl at 74 Degree Fahrenheit</u>

In addition to increasing water viscosity and thereby reducing the mobility ratio, polymer flooding also improves areal and vertical sweep efficiency by reducing the relative permeability to the polymer solution. Apparently this is accomplished by adsorption of the polymer onto the rock grains, by entrapment of polymer molecules in pore throats, and by the inability of the polymer-laden solution to enter small pore channels. Overall, the reduction in permeability allows the preferential filling of the high-permeability streaks or zones in the reservoir with a viscous slug, lowering the velocity of flow and increasing the sweep of the lower permeability zones.

Polymer flooding does not decrease the residual oil saturation significantly in the swept zone. Its primary importance is in the improvement of the areal and vertical sweep efficiencies and the acceleration of oil production before the economic limit of water-oil production ratio is reached. Polymer flooding is most efficient when begun early in the life of a water flood, particularly when mobility ratios are poor (2 to 20) and significantly permeability variations exist.

Water and Oil Mobilities

When water displaces oil through the reservoir's porous volume, the velocity of the displacement is proportional to the water mobility;

$\lambda_w = kw / \mu w$

where; kw is the effective permeability of the rock to water in the water swept zone of the reservoir and μw is the water viscosity. Water is the displacing phase and oil is the displaced phase. The oil also has a mobility

$\lambda_o = ko / \mu o$

where; ko is the effective permeability of the rock to oil in the oil bank and μo is the oil viscosity. Since the flow takes place under the same pressure gradient, the flow velocity is the same in the water swept area and in the oil bank zone only when $\lambda_w = \lambda_o$ and the ratio
$\lambda_w / \lambda_o = 1$.

Mobility Ratio Concept

The mobility ratio concept described by Craig (1980) is defined as the mobility of the displacing phase to the mobility of the displaced phase. In water flooding,

$Mw\text{-}o = \lambda_w / \lambda_o = (kw\ \mu o)/ (ko\ \mu w)$

or, dividing by the absolute permeability, the water-oil mobility ratio;

$Mw\text{-}o = \lambda_w / \lambda_o = (krw\ \mu o)/ (kro\ \mu w)$

where ; krw is the relative permeability to water at the average water saturation behind the water front and, kro is the relative permeability to oil ahead of the flood front at irreducible water saturation. It is obvious that when the mobility ratio is greater than unity, since μw is less than μo, water flows at higher velocity through the path of least resistance and breaks through into producing well prematurely.

The role of water soluble polymers is to increase the water viscosity and also to reduce the permeability of the rock to water. After water breakthrough into the producers, the flow of the two phases (water and oil) in the swept area of the reservoir is controlled by the fractional flow equation of Buckley and Leverett.

$$fw = 1 / [1 + (ko / \mu o)/ (\mu w / kw)]$$

fw = fraction of water in the flowing stream passing any point in the swept area,
ko, kw = effective rock permeability's to oil and to water respectively, at one given water saturation at one point in the reservoir
μo, μw = oil and water viscosities.

Again it is easy to observe when water viscosity μw increases and the permeability of the rock to water kw decreases, the fractional flow of oil;

$$fo = 1- fw = 1- \{1 / [1 + (kro / \mu o)/ (\mu w / krw)]$$

will increase, improving the rate of oil recovery. Permeability reduction and a higher water viscosity will increase the resistance to flow of the polymer solution diverting it toward areas unswept by water.

2.9.3 Alkaline-

Alkaline or caustic flooding is another method by which oil displacement efficiency can be improved. The benefits of this process have been known for a long time and were first observed by Squires (1917) and later by others. However, not until 1942 did Subkow offer the explanation those alkaline agents such as sodium hydroxide could react with naturally occurring organic acids in crude oil to produce soaps at the water-oil interface. The effect produced in a reservoir appears to be similar to that of micellar solutions. The difference is that alkaline flooding reduces the interfacial tensions (IFT) with surfactants generated in situ.
Despite the fact that alkaline agents are less expensive, the benefits expected from alkaline flood have not been confirmed by firm field results and still remain a possibility rather than a reality. Indeed, the major difficulty is that the process appears to be highly dependent on minerals on the surface of reservoir rock, which are not chemically inert, and on the crude oil and injection fluid characteristics. Efforts have been made, especially in the last decade to understand better the recovery mechanisms generated in alkaline flooding. Since alkaline agents are cost-efficient materials, their use, along with surfactant and/or polymer, could reduce the amount of high-cost surfactant and co-surfactant required in micellar flooding. A re-evaluation of alkaline flooding is taking place in order to find ways to reduce

the reaction of alkaline agents with reservoir minerals and to take advantage of the combined alkaline/surfactant mixture effect.

Displacement Mechanisms

Several mechanisms have been suggested regarding oil displacement by alkaline flooding. There are in fact four different mechanisms based on oil emulsification and wettability reversal. It is known that fluid distribution within the pore spaces of a rock reservoir during (alkaline) water flood depends upon the wetting and non-wetting phase saturation and upon the direction of the saturation change. In a water-wet rock reservoir, the injected water increases the wetting phase saturation, the residual oil being the discontinuous phase. In an oil-wet rock reservoir, the injected water decreases the wetting phase saturation, the residual oil being the continuous phase. It was observed also that residual oil saturation always depends on the dimensionless ratio of viscous to capillary forces defined as the capillary number: $n\mu$ / sf :(velocity x viscosity of the displacing water) / (interfacial tension between water and oil phases x porosity). When the capillary number value can be increased from 10^{-6} (conventional water flood) to 10^{-4} or more, the residual oil saturation decreases.

1.The alkaline solutions increase the capillary number value by reacting with the organic acids present in some crude oil to form emulsifying soaps. The petroleum soap or surfactant formed emulsifies oil and water and reduces the interfacial tension by two or three orders of magnitude. This mechanism is referred to as emulsification and entrainment because the oil-in-water emulsion formed is entrained by the fluid flow and can then be produced. The residual oil saturation is lowered and an incremental increase in oil recovery can result.

2.When the displacement takes place in an oil-wet reservoir, where residual oil is a continuous phase, the alkaline agent changes the injection water pH and the rock wettability is reversed from oil-wet to water-wet. This mechanism is defined as wettability reversal.

3.Even in the water-wet reservoirs the discontinuous, non-wetting residual oil phase can be changed to a continuous wetting phase if proper conditions of reservoir temperature, pH, and salinity of the alkaline solution are met .The mechanism is referred as wettability reversal from water wet to oil-wet. The presence of water droplets in the continuous oil-wet phase raises the pressure gradient of the flow through porous medium. The capillary forces are overcome and residual oil saturation is reduced.

4.A fourth mechanism, emulsification and entrapment, explains that additional oil could be produced because of the entrapment of the oil emulsion droplets by small pores. Because the flow is diverted into poorly swept or unswept areas, it improves the volumetric sweep efficiency, especially in water flooded viscous oil reservoirs or in heterogeneous reservoir.

Eg.- sodium hydroxide, sodium silicate and sodium carbonate.

Method Description

The basic alkaline flooding process starts with a softened water pre-flush injection followed by the injection of an alkaline solution of about 10 to 30 percent PV and by continuous injection of drive water. Numerous variations have been proposed. The injection of a polymer slug behind the alkaline solution to control mobility and to improve sweep efficiency is desirable if it is cost effective. Because of the complexity of the mineralogy and lithology of petroleum reservoirs the possible reactions between rock-alkaline solution-saline water and oil in the existing conditions of pressure and temperature are considerable. This explains the effort put into laboratory alkaline flooding tests and field trials to design properly the best system for specific reservoir conditions.

The state-of-the-art techniques for alkaline flooding utilize alkaline agents in combination with low concentrations of synthetic surfactant and polymer for mobility control.

2.9.4 Micellar Flooding-

In this Process - Surfactant + Salt (Electrolyte) + Alcohol (Co-Solvent) + Hydrocarbon are added to injection water to enhance oil recovery by reducing interfacial tension, modifying the rock wettability and emulsifying the oil.

Slug Size-

5-15% PV for high surfactant concentration.

15-50% PV for low surfactant concentration.

Followed by 50% PV of Polymer Thickened water Concentration 50-2000ppm .

Some Facts-

- Utilizes micro emulsion and polymer buffer slugs
- Miscible-type displacement
- Successful in banking and producing residual oil
- Process Limitations:
  - Chemical slugs are costly
  - Small well spacing required
  - High salinity, temperature and clay
  - Considerable delay in response

- Emulsion production

2.9.5 MICELLAR-POLYMER FLOODING

It is well known that the water and oil will not mix until a third component, soap or surfactant, that has affinity for both water and oil, is added. The use of an aqueous soap solution to reduce the interfacial tension of the oil-water system in order to displace the residual oil was first recommended by Atkinson. During the following years laboratory studies and reported research have shown that it is necessary to reduce and maintain the interfacial tension at 0.01 to 0.001 dyne/cm have an effect on the residual oil.

Principle and Characteristics:

The micellar solution composition which assures a gradual transition from the displacement fluid water to the oil displaced, without the presence of an interface, is as follows:

Surfactant 10-15 %
Oil 25-70 %
Water 20-60 %
Cosurfactant 3-4 %

(Cosurfactant = This is a fourth component, usually alcohol, which can be added to enhance the possibility for the micellar solution to include oil or water)

Water-soluble electrolytes such as inorganic salts may be used in preparing micellar solutions to gain better solution viscosity control. In order to have control of motilities, the micellar solution slug is driven by a polymer slug. This process is called micellar-polymer flooding or MP flooding. The micellar solution operates miscible with reservoir fluids including oil and water without phase separation, thus assuring that nearly 100 percent of the residual oil can be displaced. In the field, however, this high percentage is reduced due to reservoir rock non-uniformity. For instance, oil recovery may actually be 64 percent when areal sweep efficiency is 80 percent and invasion efficiency also is assumed 80 percent. The micellar solutions are different from emulsions due to the microscopic size of the discontinuous phase. The internal phase of a micellar solution is in the form of extremely small droplets of 10~6 to 10~4 mm compared with 10~4 mm and higher for water-oil emulsions. The micellar solutions are also referred to in the literature as surfactant slugs, micro emulsions, soluble oils, and so on. They are translucent, homogeneous, and
thermodynamically stable.

Alkaline Surfactant Polymer Flooding -

ASP is Low Cost high efficiency EOR process. It has the effect of the combined effect of alkaline, surfactant and polymer. It has been observed that ASP leads to a much higher recovery than the use of polymer , alkaline or surfactant alone. Surfactant and alkaline solution lowers the interfacial tension by over a 100 fold and thus, helps the oil to become mobile. The polymer on the other hand controls the mobility of the slug and leads to a higher recovery efficiency.

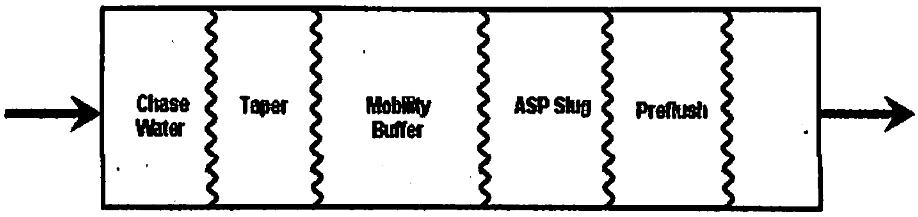


Figure 2.13- Idealised View of an ASP Flood

Slug : Alkali + Surfactant + Polymer

1-2% 1000-2000ppm 200-600ppm

Slug Size: 10-25% PV Followed by polymer in graded form concentration 300-100ppm + Chase Water.

2.10.1 Mechanism

- Lowering the interfacial tension between oil and water
- Solubilization of oil in some micellar system
- Emulsification of oil and water
- Wettability alteration mobility enhancement

2.10.2 Several variations:

- ASP
- SAP

- PAS
- Sloppy Slug

Generally applied in situations where the use of polymers, surfactants and alkaline compounds do not find individual usage. It is a fast growing technique and possesses a higher recovery of hydrocarbons than the use of any other EOR method.

Today, typical implementation of (A)SP in the field (pilot scale) take about 3-4 years. This is mainly because of the lab developmental work that goes into the choice of the various components. Additionally, implementation requires significant capital expenditure for polymer hydration equipment, blending equipment and specialty injection pumps.

The lab work that goes into designing a surfactant flooding project is as follows:

• Fluid analysis (water and oil analysis)

• Fluid-Fluid Work (phase behavior work) to identify alkali and surfactants

- Alkali identification
- Alkali concentration
- Surfactant concentration
- Static adsorption of surfactant on reservoir rock

• Core flood Work

- Oil displacement efficiency
- Adsorption studies

• Simulation or modeling work

Some factors to be considered

Some factors affecting the performance of flood-

- Capillary number
- Gravity number
- Surfactant concentration
- Remaining oil saturation after water flood
- Surfactant and polymer slug size
- Maximum surfactant adsorbed
- Ratio of reservoir brine to optimum salinity

CASE STUDY

CHAPTER 3

3.1 INTRODUCTION

3.1.1 GENERAL HISTORY

The field X started its production from May' 1969.The pay sands are having IOIP of 26.62 MMt with Ultimate reserves of 7.88 MMt. There are three sands i.e. S-I , S-II and S-III distributed throughout the field. Sand S-II is the main reservoir covering almost the entire area in this complex. The Sand characteristics are varying and hydrodynamic communication is not uniform throughout the field. Sand S-II has ultimate reserves of 3.63 MMt and having poor aquifer support.

Detailed simulation study was carried out for main sands in 1987. The envisaged recovery for field was 25.5% of IOIP at 86% water out by 2010. Subsequently,study was conducted in 1993 – 94 and suggested new locations for drilling . As on date all the proposed new locations has been drilled. The envisaged recovery in this study was 26.0% of IOIP by 2012. A.D. with 88% water cut. However, the ultimate recovery as per rec. is 32.0% of IOIP. The main sand S-II has produced 2.08 MMt (18.58% of IOIP) current oil production rate of 317 m^3 /d with an average water cut of 71%.

The initial pressure of the Sand S-II was estimated 144.0 kg/cm^2 at 1340 m datum. In the central part it declined to about 100.0 kg/cm2 by March 07. Therefore, the pressure drop in central part of the field has shown the formulation of the pressure sink. The study was conducted for the feasibility of water injection in Sand S-II for pressure maintenance to improve recovery. The study indicates improvement in oil recovery by injecting water in this main sand. However, the same was not recommended as incremental gain with 20 injectors was found to be less than 1% of in place oil reserves. The peripheral injection in such a hetrogeneous reservoir with poor hydrodynamic communication in many areas is more likely to give low recovery. Pattern injection may be the answer to this problem. As the current pressure in the central region has shown a decline of around 40 to 60 kg/cm^2 from the initial pressure, therefore, well no. 90 was proposed for trial water injection in this area for pressure maintenance.

3.1.2 ALKALI-SURFACTANT –POLYMER (ASP) FLOODING & ITS SCOPE FOR IMPROVING OIL RECOVERY IN FIELD- X SAND S-II

Demand for oil is increasing at a much faster rate compared to increase in production, resulting into widening the gap in demand and supply of oil. also, since the cost of exploration of new oil fields and development of exiting fields is escalating, implementation of cost effective IOR technique to bridge the gap and to keep sustain production is of immense importance. One of such technology is the use of low cost alkaline chemicals combined with Surfactant and Polymers, which is called ASP flooding. Even in the most favourable reservoirs, conventional primary and secondary recovery schemes fail to recover as much as 40-60% of original oil in place. Many reservoirs with less then ideal conditions may still have more than 80 to 90% of he original left after primary and secondary recovery . Such reservoirs are an certainly a attractive target for application of new technology.....

The important features of this technology are

- low cost , high efficiency process.
- Cheaper than other IOR process.

- In use worldwide.

It can be very well be implemented at secondary as well as tertiary stage for wider range of oil characteristics. The process is favorable for reservoir having adverse mobility ratio and also for the oil having high interfacial activity.

ASP flooding has emerged as most economical alternative of conventional micellar-polymer flooding. Processes has economically produced additional oil over water flood in field on pilot scale by reducing the capillary forces trapping the oil and improving the overall contact efficiency . Process is designed to combine the best features of all the three viz surfactant, polymer and alkaline flooding and eliminates some of negative aspects of each process.

In view of above facts, the preliminary laboratory studies for applicability of ASP flood were carried out for Sand S-II in Nov' 1996. Based on encouraging preliminary laboratory results further detailed core flood studies on Natives core were done, results of which are given in the present report. In view of very encouraging core flood results, conceptual design for ASP pilot for Sand S-II is prepared.

3.2 RESERVOIR GEOLOGY

3.2.1 STRUCTURE

The basement configuration of the entire basin is characterised by NNE-SSW trending highs separated by lows of different magnitude. The field is once such prominent high extending North-South . In the area, the north trending faults are postulated based on missing are sub-parallel to each other. The fault pattern does not co-incide with one another. An axial shift has been observed in structures at different levels.

3.2.2 SAND MODEL

GENERAL

Generalized stratigraphy of the pay horizons has been given in the figure-3.1.

The pays are developed between two prominent shale bands (lower and upper shale) and consist of sand, shale , coal and occasionally sideritic siltstone layers. The pays have developed in between two coal sections and also within the top coal as shown in figure-3.1. Due to extensive development throughout the area and the quantum of geological reserves, the 3 different pay zones have been the main objects of development since discovery.

3.2.3 FIELD X UNIT SUB-LAYERS

Interspersed between top and bottom coal and at places within top coal a series of sandstone and silt layers have developed which is known as Field X main pays. The layers of main pay have been designated as S-I, S-II and S-III from top to bottom over major part of the structure.

Starting from bottom, overlying the bottom coal sand S-III has developed which is characteristically present in South, Central and West Field area. Overlyig S-III in Southern and Western part of the field, sand S-II has been developed. S-II is overlain by low resistivity shale which is followed by another group of sand named as S-I.

The sand S-II is main producing sand and having maximum IOIP of 11.19 MMt and other sand S-I & S-III are having 4.77 MMt and 1.87 MMt respectively as per rec. The sand S-II has produced 2.08 MMt of Oil, which is 18.58 % of IOIP as on 1.4.97 . The sand is producing oil at the rate 317 M^3/d with average water cut of 71.0%.

Development of sand S-II is confined to the northern , Western, Central and Southern part of field. The oil pay thickness in the main pool varies from 2.0 to 13.0 m in Central region , 2.0 to 5.5m in West region and 2.0 to 5.0 m in the northern part of the field.

3.2.4 LITHOLOGY

The Field X units consist of alternating bands of sand, shale, coal and occasionally siltstone. The pay sands are fine to very fine grained and moderately well to well sorted. Texturally these sands are sub mature to mature quartz arenite and quartzwacks.

3.3 FIELD DEVELOPMENT & RESERVOIR CHARACTERISTICES

3.3.1 FIELD DEVELOPMENT

First technological scheme was prepared in 1972 for sand II and III after drilling of 21 wells and estimated IOIP 4.79 MMt. Additional 12 wells were recommended for drilling with oil rate 390 m^3/d and envisaged oil recovery of 36.8% at 60% W/c . Detailed simulation study was carried out for Sand II & III in 1982-83 after drilling of 69 wells and established reserves in other pay also. New 33 locations were recommended, out of which released 30, finally 27 were drilled and 3 were concalled. In this study envisaged rate was 700 m^3/d with a plateau period of 6 years and expected recovery was 26% by 2010 A.D. with 88% W/C. Development status was reviewed in May' 1986 and 4 location were released for pay sands and drilled. In 1987 – 88, a comprehensive review of the pay Complex was done .Detailed simulation study was done for different pays. Total IOIP was estimated 41.55 MMt and recommended 35 locations. Out of which 29 were drilled. Envisaged peak oil rate was 1500 TPD with plateau oil rate of 1300 TPD for 5 years and expected recovery was about 26.4% by 2010 A.D. From the simulation studies carried out, for sands envisaged recovery was 25.95% of IOIP by 2012 A.D. with 88% W/C and peak production rate 1010 M3/d. The predicted and actual performance of Sands are table-1.

3.3.2 RESERVOIR, ROCK AND FLUID PROPERTIES

The reservoir rock and fluid properties of Sand SS-II are given in table – 2 & 4.

The Oil pay thickness in the main pool varies from 2.0 to 13.0 m in central region, 2.0 to 5.5 m in western side and 2.0 to 5.0m in the northern part of the field . The porosity is in ranges between 20% to 30%. The oil saturation in Central area varies from 50% to 80% . In northern part of the field the variation is between 50 to 70%.

The pressure build up data and core studies permeability data are given in table-3. The build up permeability is in range of 500-1500 md. and core permeability is of order of 500-110 md, which is very well matching with build up permeability data.

Sp. gr. of stock tank oil is 0.8300. Formation Volume factor is 1.090 (v/v). Core analysis shows that residual oil saturation is in the range of 25 to 35%.

Physico-chemical properties of field's crude oil and analysis of formation & tube well water is given in table-4. Its crude is having 7.7% asphaltene and 20.77% resin by weight. The crude is acidic in nature, having acidic component of 3.65 mg. KOH/gm of crude oil.

3.3.3 RESERVOIR PERMEABILITY VARIATION

For a reservoir with large variations in rock permeability the micro-scale displacement of oil will be vary inefficient . Fluids will flow preferentially in the highest permeability sections of the reservoir, often leaving the majority of the oil unaffected in the lower permeability zones. Continued injection of water will affect those high permeability zones in which the micro-scale recovery mechanisms have already been exhausted.

The permeability variations govern the efficiency of drainage or sweep efficiency . The variations in permeabilities are principally related to depositional environments. Mobility ratio also controls the sweep efficiency. Table-3, also indicating the wide variations in the permeability from maximum 1080 md to minimum 480 md. Besides the pressure permeability data, the core permeability measured during the displacement studies on native cores, also confirmed the permeability variation in Sand S-II. With the use of above permeability values the permeability variance coefficient has been arrived at 0.5 for Sand S-II.

3.3.4 RESERVOIR OIL VISCOSITY VARIATION

The oil recovery depends on the mobility contrast of two fluid i.e. displacing fluid (water) and displaced fluid (oil). The mobility ratio is defined as.

$$\text{Mobility ratio} = \frac{(K\ Water\ /\ U\ Water)}{(Koil\ /\ U\ oil)}$$

where,

Koil = The effective permeability to oil at immobile water.

Kwater = The effective permeability to water at residual oil saturation.

Oil & Water = Viscosity of oil and water.

An increase in mobility ratio exacerbates viscous fingering and decreases the reservoir contact efficiency, result in overall oil recovery. Besides the relative permeability, the variation in viscosity of crude oil affect the mobility contrast i.e. more the viscosity more will be contrast. In Sand S-II, there is a wide variation in live oil viscosity as given in table-5. The viscosity is in range of 5-20 cp at initial reservoir pressure. The viscosity is in increasing trend from Northern to Southern part of the field's Sand S-II.

3.3.5 ADVERSE MOBILITY RATIO

During displacements on Native cores, the effective permeability of water at residual oil saturation and permeability of oil at immobile water saturation were determined. Using these values and viscosity of water and oil the mobility ratio was calculated and found in range of 3-5. Moreover, the ratio was also calculated by using the Core permeability data of well no.183 study of which was done in Core laboratory. The ratio was found of the order of 4-8. The results are given in table-8. It is clear from the study that adverse mobility ratio is exiting in the reservoir, resulting recovery into low oil.

3.4 LABORATORY STUDIES

3.4.1 BACK GROUND

The preliminary laboratory investigations on applicability of ASP flood process in sand S-II, has already been established for the field. In this study various indigenous petroleum sulphonate samples received from different sources, were tested on the basis of their thermal stability, IFT measurements, emulsion formulation study, CMC values and compatibility study between the three chemical components of ASP flood process. The objective was to see their suitability prior to displacement experiments on native cores. The best screening results were found for two petroleum test are given in table-6. Sodium Carbonate was selected and used as alkali and polymer Pusher-1000 was selected on the basis of compatibility with alkali and surfactant study for flood experiments. A schematic view of the ASP flood process is given in figure-3.1. The reason of using Sodium Carbonate as alkali compared to other alkalis, is due to its better propagation in porous media as given in literature (ref. 14). Moreover, it is being used in most of ASP pilots in the USA and China etc.

The field X crude oil has sufficient amount of acidic component (0.33) mg. KOH/gm). Therefore, Sodium Carbonate reacts with these acidic component and generates some surfactant, which reduces the IFT to 240 milli dynes/cm. from 2400 milli dynes / cm. However, with the use of 0.20 wt% HLA alongwith 1.0 wt% alkali and 0.15 wt% AOS alongwith 1.0 wt% alkali the IFT value further goes down to 10.0 milli dynes / cm and 15.0 milli dynes / cm. respectively. The resuls of IFT values for optimisation of alkali and surfactant concentration are given in table-7.

Based on encouraging preliminary laboratory results on eight displacement experiments on native cores for evaluation of ASP slug for sand S-II were carried out with the following main four objectives.

1) Selection of best surfactant in term of improving oil recovery (Expt. No. 1 & 2).
2) Slug size optimization (Exp. No. 3 .4 & 5)
3) Effectiveness of ASP slug in improving oil recovery at Tertiary (ROS) stage (Expt. No.6)
4) Displacement efficiencies by polymer flooding at secondary as well as tertiary stages (Expt. No. 7 & 8).

3.4.2 BRIEF RESULTS

The brief results to each experiments are discussed below: Summary of all displacement experiments were done to evaluate the effectiveness of two surfactants viz. HLA and AOS at secondary stage. A ASP slug consisting of 1.5 wt.% sodium Carbonate, 0.20 wt % (Active) surfactant and 1000 ppm polymer pusher-1000, was continuously injected. The recovery results of these two experiments are plotted in figure-3.2. The results show the comparable displacement efficiencies of two surfactant AOS (70.71% of IOIP) as compared to surfactant AOS (67.90% of OIIP) , moreover adsorption of AOS was found in lower side then to surfactant HLA as shown in figure-3.3. Therefore, surfactant AOS was considered as more effective in comparison to surfactant HLA and was used in all further experiments. The plot of injected alkali concentration eluted and pore volume injected is given in figure -3.4.

3.4.3 SLUG SIZE OPTIMIZATION

Three experiments were done for optimization of ASP slug, using slug size of 20% 25% and 30% pore volume respectively. The slug, in all the three experiments was consisting of ASP slug:

i)	Na2CO3	1.5%
ii)	Surfactant , AOS	0.20 WT. % (100% AM)
iii)	Polymer (Pusher-1000)	1000 ppm

Followed by of polymer buffer in grading. The ASP displacement efficiencies in these experiments were 66.2%, 69.9%, and 72.5% of IOIP respectively. The graphs between displacement efficiency and fluid injected are shown in figure 3.5. From the plots, it is obvious that a 25% PV of slug size seems to be more optimum. However, more oil recovery is found in 30% PV slug but this increase in oil recovery in respect of increase in slug size from 25% to 30% PV is very less as compared to increase in oil recovery from 20% to 25% PV of slug size . Hence the slug size of 25% PV was found to be optimum . Adsorption of alkali and surfactant was calculated with 25% ASP slug, graph is shown in figure-3.6. The adsorption of surfactant was found 0.10 mg/gm of rock and alkali was 0.25 mg/gm of rock which was in lower side in comparison to continuous slug and is in agreement with literature value.

3.4.4 DISPLACEMENT EFFICIENCY AT TERTIARY (ROS) STAGE

The experiments at tertiary stage was done on 20 cm. long composite native core pack consisting of core plugs of three wells (nos. 115, 183 & 20). This experiment was planned to see the effect of ASP flood process at residual oil saturation and effect of long Native core on displacement efficiency. The water flood displacement efficiency was 38.0% of IOIP at 100% water cut. A 25 % PV slug size consisted of alkali-surfactant and polymer (800 ppm), followed by 30% PV of mobility buffer with average concentrations of 400 ppm and finally about 1 PV of the field's tube well water was injected. The ASP flood displacement efficiency at tertiary stage i.e. without resaturation of the core pack with oil after the water flood was found to be 19.7% over water flood. The ultimate recovery was found to be 57.7% of IOIP. The results of oil recovery are shown in figure – 3.7.

The efficients obtained during flood studies were analysed for Alkali / Surfactants recoveries to calculate the adsorption losses. The Alkali concentration was determined by standard Acid – Base titration and surfactant concentration was determined by two phase hymine-Dye Titration method. The plots of Alkali and Surfactant recovery in effluents Vs. PV injected are shown in figure – 3.8. It was determined that surfactant and alkali losses are 75% and 80% of the original concentration respectively. On the basis of these results the surfactant adsorption was found in range of about 0.10 to 0.13 mg/gram of rock, which is in the lower side as against the reported literature value (0.15 – 0.25 mg/ gram of rock). Alkali consumption was found of the order of 0.25 to 0.40 mg/per gram of rock, which is also in range of reported literature values.

3.4.5 DISPLACEMENT EFFICIENCY BY POLYMER FLOODING

Two more experiments were carried out to see the applicability of polymer flood process in the field at secondary as well as Tertiary stage. The first experiment was done for polymer flooding at secondary stage. A slug of 25% PV of 1000 ppm polymer was injected, followed by 30% PV of mobility buffer with average concentration 600 ppm of tapered polymer . The ultimate oil recovery was found 59% of OIIP, which is about 11.0% lesser than ASP flooding. The results of oil recovery are depicted in figure-3.9.

The second experiment was done to evaluate the effectiveness of polymer flooding at Tertiary (ROS) stage. This experiment was done in similar fashion as the first experiment. The ultimate oil recovery was found to be 49.7% of IOIP, which is about 6.0% higher then the water flooding. Thus, plain polymer flooding is not so effective and economical viable at tertiary stage.

A comparative picture of oil recovery by ASP flooding in comparison to polymer flooding is shown in figure – 3.10. It is obvious that a small amount of alkali and surfactant with polymer improves displacement efficiency significantly.

Therefore, ASP slug of 25% pore volume, consisting of 1.5% alkali, 0.20% (100% AM) surfactant AOS and 800 ppm of polymer Pusher-1000 would give the best results with tapered mobility buffer of 30% PV of polymer Pusher-1000 from 600 ppm to 200 ppm.

3.5 ASP FLOOD PERFORMANCE CALCULATION

For enhancing oil recovery from the reservoir water flooding, polymer flooding and ASP flooding experiments were carried out and the results of ASP flooding were found very encouraging. Using the laboratory data, performance calculations were made for water as well as ASP flooding by the following methods.

3.5.1 CAPILLARY NUMBER CORRELATIONS METHOD

The main role of surfactant is to reduce the interfacial tension between reservoir oil and water. The interfacial force at the fluid –rock interface is responsible for the retention of residual oil in porous media.

The residual saturation of a displaced phase can be correlated by means of "Capillary number". This involves the ratio of viscous to capillary forces.

$$\text{Capillary number} = \frac{\text{Viscous Forces}}{\text{Capillary Forces}} \qquad \frac{V^{*}u}{ro/w}$$

The capillary number between Filed X crude oil and formation water without using surfactant was first calculated by putting the value of v-5ml/hr and IFT, ro/w=2400 milli-dynes / cm. The value of capillary number was found of order of $7.5^{*}10^{-7}$. The interfacial tension between field X crude oil and tube well water having 0.2 Wt% (active) surfactant and 1.5 Wt%

alkali was measured in the laboratory and found of order of 10 to 15 milli –dyne/ cm. With these values the capillary number was calculated and found to be of the order of $5.99*10^{-4}$.

As per literature the value of capillary number of the order of 10^{-7} are most common for water flood and is generally operate at value of Nca < 10^{-5}. At the value of capillary number less than 10^{-5}, the residual oil saturation is relatively constant, and not a function of magnitude of Nca. At the value of Nca above 10^{-5}, the magnitude of the residual oil saturation decreases.

In the present study, due to IFT reduction with the use of surfactant and alkali, the capillary number increases about 1000 fold, which is resulting in decrease of residual oil saturation in order of 12-14% PV as calculated by correlation through standard chart given in table-15. The additional recovery over water flood comes out to be order of 18-22% of IOIP.

3.5.2 FRACTIONAL FLOW THEORY, BUCKLEY-LEVERETT METHOD

Gary A. Pope applied fractional flow theory to enhanced oil recovery by low-tension flood. Since, ASP flood process is a low tension flood process as very small amount of surfactant is to be used in this technique. Author further characterized the process by the following characteristics. First, it is an aqueous process involving no transfer of chemical (surfactant) to oil. Secondly, it is a low concentration process. Third, the chemical lowers the interfacial tension enough to make the capillary number high enough to detrap oil. Fourth, from a practical point of view, polymer must be added to the chemical solution for mobility control (slug as well as in chase water for mobility control). Thus, above characteristics very well match with ASP flood process.

For this method, the fractional flow of water versus end face saturation cruves called fractional flow curves were generated using the fraction of oil and water in effluents obtained during displacement studies done at secondary as well as tertiary stages.

The fractional flow of water depends upon the relative permeability and viscosity of water and oil phase. Relative permeability is a significant factor in oil recovery in that it dictates

- initial and water flood oil saturations
- target oil volume
- mobility ratio

Relative permeability is affected by wettability of the rock, capillary heterogeneity, interfacial tension, capillary pressure, applied pressure gradient, and saturatin history. Since, in ASP slug there are two main role of surfactant and alkali first one is to reduce the interfacial tension and second one is to change the wettability of the rock. The capillary heterogeneity is controlled by polymer. Therefore,to see the combined effect of alkali-surfactant and polymer on the process. The fractional flow curves f water, polymer and ASP flooding were generated and curves are shown in figure-3.11 & 3.12. It is obvious from the curves

- Curves shift to right direction in case of ASP flood and end at 79% PV of water saturation as against of 62% PV of water saturation during water flood at 95% water-cut in secondary stage. This means that 17% PV of oil saturation can be produced as incremental oil over water flood at secondary stage, which comes out to be 23% of IOIP.
- At tertiary stage, the curve also shifts in right direction. In this case ASP slug was injected after water flood (100% water-cut), the curve starts at 55% PV of water saturation and end at 69% PV

of water saturation. This means that 14% PV of oil saturation may be produced as incremental oil over water flood at tertiary stage which worked out to be 18% of IOIP.

Therefore, the displacement of oil by ASP flood seemed to be favorable because of the relative permeability and viscosity effects. It is also confirmed from these curves that polymer concentration used in ASP slug and later in mobility buffer are also adequate to prevent the viscous fingering.

3.5.3 DISPLACEMENT EFFICIENCFY METHOD

In the third method, the displacement efficiency obtained during flooding studies carried out on native cores at secondary as well as tertiary stage was used for performance prediction of after and ASP flooding. The ultimate recovery was calculated by multiplying the displacement efficiency by sweep efficiency and conformance factor. Using the different water oil ratio and mobility ratio during the displacement studies, the sweep efficiency was estimated from the standard charts. The value of sweep efficiency factor at 95% water-cut was estimated and found 0.82 and 0.86 for water and ASP floods respectively. The conformance was calculated as by calculating the permeability variance co-efficient. The Dykstra-Person permeability variance coefficient (v) was calculated with the use of laboratory as well as Build – up permeability data of wells and value obtained is about 0.50 for water. In case of ASP flooding the value of the variance coefficient is reduced and estimated to be 0.40 due to the facts that not only the polymer used in ASP reduces the water permeability but also added surfactant and surfactant generated through alkali reaction with acidic component of crude oil, both reduce the interfacial tension at oil-water interface and form an emulsion of reservoir oil. This formation of emulsion (trapped in pore restrictions) results in reduced water mobility (K/μ) and improved vertical as well a real sweep efficiency through substantially increased in viscosity and solubilisation of oil. Thus, conformance factor was calculated as 0.75 and 0.84 for water and ASP flooding. One the basis of these data, the total volumetric sweep efficiency was estimated to be 0.62 and 0.72 for water and ASP flood respectively. Thus, by multiplying this volumetric sweep efficiency with displacement efficiencies obtained n laboratory , the ultimate oil recovery for the pilot was estimated to be 45% of IOIP at tertiary stage and 50% of IOIP at secondary stage. The incremental oil recoveries over water flood were estimated to be 17.0% of IOIP at tertiary stage and 23.0% of IOIP at secondary stage.

Thus, through the prediction methods the incremental oil recovery over water flood is estimated in the range of 17.0 – 23 % the IOIP by the above methods at the above methods at the field scale on pilot level. However, recovery of 20% of IOIP over water flood was considered for calculating the additional oil recovery by ASP flooding in pilot area.

3.6 FIELD PILOT DESIGN

The results of laboratory displacement studies and performance prediction of ASP flood are encouraging and the process needs to be evaluated by conducting a pilot test in the Field X sand S-II so that sufficient data can be generated to permit appraisal before full scale field implementation. The pilot test is a R&D extension in the field conditions.

3.6.1 SITE AND PATTERN SELECTION

The present pilot scheme is prepared with the use of exiting producing wells in which inter spacing is about 30 to 400m. As on date drilling of new wells for pilot producers is not required as field has been developed with a close spacing.

The pilot location has been selected keeping in view of the average petrophysical characteristics of the area. This area is away from fault. The pattern of pilot selected one inverted 5- spot pattern, having one injector (well no.90) and four producers (well no. 6, 45, 52 and 118).

The thickness weighted average petro-physical properties used for performance prediction and to calculate the ASP flood recovery are given below.

Porosity	oil Saturation	Pay thickness
(%)	(%)	(m)

22.27	62.54	7.20

ASP flooding being a three chemical components system, more amounts of chemicals is required for this process. Therefore, the present scheme is recommended to initiate the ASP slug injection through one injection well no.90 to assess the viability of the process. This well had been proposed for trial water injection in 1995, due to pressure sink in this area. Therefore same area has been considered for the present scheme. The selected injector has no production loss as it is closed due to water loading since' 1986.

3.6.2 DETAILS OF PILOT WELLS

3.6.3 PETRO-PHYSICAL PROPERTIES

The petrophysical properties of the pilot area wells are given in table-9. These values has been taken from formation evaluation/well completion report. The thickness weighted average values were calculated and taken for calculation of pilot area, volume etc. The average porosity calculated is 22.27%, Saturation 62.54% and thickness 7.2 m. The total pilot area calculated is 120000 m^2. The oil formation volume factor is 1.090 and density is 0.8904 gm/cc.

3.6.4 PRESSURE-PRODUCTION

The latest production data with cumulative oil production and pressure data of each well of proposed pilot area is given in table-10. The most of the wells of the pilot area are cutting water cut in the range of 70-80%. Two wells no.6 & no.90 has been ceased due to high water cut and other three wells are on artificial lift. The average oil and fluid production rate per well are estimated to be 5-10 m^3/day and 20-30 m^3/day respectively. The performance graphs of all the wells are given through table-20 to 24. All the five wells of proposed pilot area have produced 0.2582 MMt of oil as on 1.8.97, it indicates that sufficient amount of oil has already been taken form the pilot site. By the time EOR process will come the left over oil will be in the form of trapped oil by capillary forces. In view of above facts the proposed pilot area is seemed to be most suitable for ASP flooding.

3.6.5 PRE-PILOT EVALUTION

The injectivity and pressure fall-off test in the injection well should be conducted and if necessary, suitable stimulation job should be done. The pulse test (PLT), using electronic pressure gauge should also be conducted to establish inter well communication and ensure that no permeability barrier exits between injection and production wells.

3.6.6 FLUID INJECTION PROGRAMME

For the ASP pilot test, the fluid injection sequence would be (i) ASP slug (ii) Mobility Buffer, and (iii) Chase water. The fluid injection schedule have been prepared and given in table-11. This may be reviewed depending upon the injectivity tests. This table also gives the daily injectivity tests. This table also gives the daily requirement of various chemicals during the fluid injection of pilot. The details of the fluid to be injected are discussed below.

3.6.7 ASP SLUG

The ASP slug would consist of 1.5Wt % of Sodium Carbonate, 0.2. Wt% (active) petroleum sulphonate and 800 ppm of polymer dissolved in field's tube well water. After detailed laboratory studies a 25 % PV of slug size was considered to be optimum for pilot test in the field. For the injection in one well no. 90, 48107 m^3 of ASP slug would, therefore, be injected. It would require 722 tons of Sodium Carbonate, 96 tons of 100 % active petroleum sulphonate and 38.5 tons polymer.

3.6.8 MOBILITY BUFFER

The mobility buffer would be injected immediately after injection of the ASP slug. It has been designed to provide low mobility and high viscosity buffer to avoid fingering of subsequently injected low viscosity fluids into the ASP slug. The mobility buffer would consist of a series of viscosity graded slug of polymer solutions. The first slug would be 0.10 PV of 800 ppm polymer solution in field's tube well water. The concentration of subsequent slug would be brought down to 400 ppm and 200 ppm each of 0.10 PV. Therefore, total volume to be injected would also be 0.30 PV, which is equivalent to 57728 m^3 with and average polymer concentration of 600 ppm for one injector. It would require 22.05 tons of polymer. Suitable oxygen scavenger and biocide (if necessary) would also be added to polymer solution.

3.6.9 CHASE WATER

The mobility buffer would be followed by chase water. Field's tube well water, would be used for this purpose. It is expected that about 0.55 PV, which is worked out 105835 m^3 would be required for the completion of the pilot.

3.6.10 SURFACE FACILITIES

The conceptual design of the surface facilites and their lay out has been given in figure-3.19. This is prepared for injection of fluid in one injection well. The field's tube well water would be received into storage tanks of 250 m^3 capacity. The field's tube well water would be filtered. Through coarse filter followed by 8 micron filter for removal of the suspended particles. The maximum tube well water requirement is expected to be 250 m^3/day. Therefore one tank of 250 m^3 capacity is recommended to ensure uninterrupted water supply.

During the ASP slug injection phase, field's tube well water would be used for preparation of ASP slug. The petroleum sulphonate and Sodium Carbonate would be fed through metering pumps to a static mixer there after it would be mixed with filtered field tube well water using another static mixer and taken into slug preparation tanks/storage tanks it would be kept under constant slow stirring. The polymer solution from the polymer dispersion unit would be passed on to the dilution tank, after mixing with field's tube well water. The solution will also be allowed for aging of about six hours in the storage tanks for complete dissolution. Two tanks of 200 m^3 capacity each are recommended for preparation of ASP slug/polymer storage tanks. This polymer solution will be allowed to mix with alkali-surfactant solution by keeping the solution under constant slow stirring. Therefore, two tanks for slug preparation/storage tanks each of 200 m^3 capacity with arrangements for stirring and creating nitrogen atmosphere are recommended so that slug can be prepared in one tank and injection can be continued from second tank.

During mobility buffer injection phase, the ASP slug preparation facility would be by passed and the filtered field's tube well water storage tank would be first dosed with appropriate amount of biocide and oxygen scavenger to remove dissolved oxygen and then passed through the polymer dispersion unit. The slug preparation / storage tanks where it will be slowed a retention time of minimum 6 hrs. to make it homogenous. In these tanks the polymer solution would be kept under nitrogen atmosphere so as to avoid contact with atmospheric oxygen. The polymer solution would be then filtered through 8 micron filters and injected into the formation.

On completion of injection of mobility buffer the polymer dispersion unit as well as slug storage tanks would be passed and field's tube well water would be injected after filtration unit until completion of the pilot test.

For injection of various fluids one unit of duplex/triplex plunger pumps with injection capacity of minimum200 m^3/day are recommended. For filtration of surfactant slugs, two units each of 8-10 microns filters are recommended so that when one unit is in operation, the other can backwashed and make ready for use. It is recommended to have epoxy coated mild steel pipe line as well as tanks. For complete monitoring the prepared and injected fluid, flow meters should be installed at both inlet and outlet of all tanks and also at flow arms of injectors and producers.

For collection/disposal of fluids, if possible existing surface facilities of field's CTF/GGS can be utilized.

3.6.11 PILOT PERFORMANCE MONITORING PROGRAMME

Details of various sample to be taken during the pilot test, along with proposed analysis are given in table-12. Besides that records of injection data, pressure production data should be maintained. These data would be useful for pilot performance evaluation and full scale implementation of the process in the field. The suitable tracers may be added n the ASP slug solution. This will help to locate any channels/high permeability zones.

3.7 TECHNO-EONOMIC ANALYSIS

The economic of Field X Sand S-II for ASP flood process has been worked out for one inverted 5-spot patterns with the exiting wells. The envisaged project cost is Rs. 4.62 Cr. Which include Rs. 1.20 Cr. as capital investment, Rs. 2.41 Cr. For chemicals costs and Rs. 1.01 Cr. as operational cost. Cost of Capital equipment and surface facilities have been taken on the basis of ASP pilot, nearby field's project. It includes surface facilities for plant capacity of 250 m^3/day, polymer dispersion unit, injection pumps, high pressure injection lines for 1 well. The details of capital items and breakup of surface facilities are given in table- 13. The operational cost was also taken on the basis of ASP pilot done on a nearby field and chemical cost was based on market survey. Details are given in table-14. The revenue expected from the pilot with current oil price @ Rs. 1991/ton is about Rs. 4.0 Cr. Considering 20.0 % additional recovery over water flood. The extimated oil recovery against fluid injection is given in table-15. It is pertinent to mention that Capital Cost of Rs. 1.20 cr. are reusable in case of expansion/commercialization of the project. Moreover, the expenses occur in producing additional oil over water flood is about Rs. 0.80 cr. as capital cost and Rs. 2.41 cr. as chemical cost. Details of techno economics are given on next pate (table Eco-1).

3.7.1 ECONOMIC CALCULATION **Table-Eco-1**

ESTIMATED COST (FIELD X SAND S-II)

(FOR INVERTED 5-SPOT PATTERN)

i. ESTIMATED COST OF CAPITAL EQUIPMENTS

		Rs. Lakhs
1.	Polymer Dispersion Unit complete with Oxygen Scavenger and biocide dosing system	50.0
2.	Injection pump, @ 250 m^3/d (1 Nos)	13.5
3.	High pressure injection line @ Rs. 3.50 lakhs/km for 1 km.	3.5
4.	Cost of surface facilities	53.0
	Total Capital investment	**120.0**

ii. OPERATIONAL COST **101.87**

iii. CHEMICAL COST

1.	Petroleum sulphonate @ Rs. 40-/-per kg (100%AM) 96.2 tons	38.5

2. Polymer @ Rs. 200-/- per Kg. (61.5 tons)	123.0
3. Sodium Carbonate @ Rs. 10-/- per Kg. 721.6 tons	72.2
4. O.S, Biocide & Tracer	7.0
Total cost of Chemicals	**240.7**

Total cost of pilot = Capex +Opex + Chemex

= 120.0 + 101.87 +240.7

= Rs. 462.57 lakhs

iv REVENUE EXPECTED

IOIP	= 98244 tons (STO)
Water flood recovery	= 27-30% of IOIP
ASP flood recovery	= 45-50 % of IOIP
ASP flood recovery	= 20 % of IOIP
Over W/F	= 19649 tons
Revenue generated	= 391 lakhs @ Rs. 1991 per ton

3.8. CONCLUSIONS AND RECOMMENDATIONS

3.8.1 CONCLUSIONS

1. The reservoir and oil properties show that ASP flood process is a suitable EOR technique for Field X Sand S-II. ASP system recovered more oil as compared to polymer process during laboratory experimentation.

2. Laboratory results of core floods on Native cores are encouraging. ASP slug size of 25% PV, consisting of 0.20 Wt % (100% AM) Petroleum Sulphonate, 1.5 Wt% Sodium Carbonate and 800 ppm of polymer is found to be optimal. The envisaged displacement efficiency is 70.0% & 58.0% of IOIP at secondary and tertiary stages respectively.

3. After 25 % PV of ASP slug a mobility buffer of 30 % PV with 400 ppm average concentration of polymer and finally about 0.55 pore volume of field's tube well water as chase water would be optimum for field's pilot.

4. Pilot area was selected as proposed injector has already been recommended for trial water injection to maintain the pressure depletion in this area.

5. On pilot, the incremental oil recovery over water flood was calculated of order of 17.0 % to 23.0 % of IOIP. The ultimate recovery was envisaged in range of 45 % to 50.0 % of IOIP by ASP flooding.

6. For the field implementation and to calculate the expected oil recovery form the proposed patterns and incremental oil recovery over water flood is envisaged to be 20 % of IOIP through ASP flooding.

7. Fluid injection schedules as well as sampling and analysis programmes have been prepared for better implementation and effective monitoring of the pilot project.

8. One inverted 5-spot pattern has been considered for the pilot demonstration project. The input required are

- Sodium Carbonate	721 tons
- Surfactant (100% Active)	96 tons
- Polymer	62 tons

9. The successful implementation of this technology may give economic impact to the organization.

3.8.2 RECOMMENDATIONS

It is recommended to;

- Implement the pilot ASP flood project in Field X Sand S-II in one inverted 5-spot pattern.
- Carry out injectivity test in the injection wells before injection of ASP slug @ 120 m^3/d. The pilot programme such as injection rate etc. should be reviewed on the basis of the results of injectivity test.
- Carry out PLT test to interwell communication and to ensure that no permeability barrier/channel is exiting between injection and production wells.
- In case of channel, it may be treated with Aluminum - gel/Chrome-gel before stating regular injection.
- Monitor the injection & production rate by installing the flow meters in the flow arms, injection pressure and production rate periodically. Independent facility for measuring the production form the pilot wells.
- The process is techno-economically attractive and the pilot demonstrative project may be started at the earliest to assess techno-economically viability of commercial application.

Table-1

YEAR	ACTUAL PERFORMANCE				PREDICTED IN SIMULATION			
	NO. OF PRODUCERS	OIL RATE (m3/d)	W/C (%)	RES. PR. (kg/cm2)	NO. OF PRODUCERS	OIL RATE (m3/d)	W/C (%)	RES. PR. (kg/cm2)
1987-88	49	687	37	128.63	52	697	38	137.6
1988-89	48	759	35	127.05	71	793	46	136.1
1989-90	52	824	38	123.14	89	954	48	134.4
1990-91	61	854	49	118.46	96	1012	50	132.9
1991-92	60	857	54	116.51	98	970	54	132.2
1992-93	63	854	58	102-113	97	876	58	131.8
VARIANT RECOMMENDED FOR CDP								
1993-94	60	626	60	108	61	685	61	119.9
1994-95	65	678	62		75	735	64	117.1
1995-96	71	735	65		92	1010	61	112.2
1996-97	70	732	71	100	92	968	65	110.6

Predicted v/s actual performance for Field X main pays

Table-2

Reservoir Properties of Sand

1) Field : Field X
2) Reservoir : Sand II(sandstone)
3) Depth : 1340 m
4) Initial Pressure : 144 kg/cm^2
5) Saturation Pressure : 92.5 kg/cm^2
6) Average Pay Thickness : 6.0 m
7) Temperature : 82 degree centigrade
8) Oil Viscosity at Reservoir Condition : 5-20 cp
9) Initial Oil Saturation : 65 %
10) Porosity : 24%
11) Permeability (core) : 500-1100 md
    (build up) : 900-1500 md
12) Oil Density : 27 degree API
13) Residual Oil Saturation :
    Core Laboratory: 25-35%
    C.F.Laboratory: 35-38%

Table-3

Permeability Data

A) Build up Permeability Data-

Sl. No.	Well no.	Perforated Interval(mtrs.)	Permeability(md)
1.	No. 41	1426-1429 1431-1433.5	934.6
2.	No. 10	1419-1429 1434.5-1437.5	451.4
3.	No. 3	1435-1440	962
4.	No. 80	1435-1438 1443-1446	1083.2

B) Core Permeability-

Sl.no.	Well no.	Interval(mtrs.)	Permeability(md)
1.	No. 183	1446.5-1453.4	579-1091
2.	No. 115	1431-1437.7	310-579

Table-4

Composition of Field X Crude

1) Asphaltene (Precipitated in 4-60 Petroleumether),%w/w : 7.7
2) Wax Content (Precipitated in Ethyl-lolotol and Emkat 20c),% w/w : 4.33
3) Resin,%w/w : 20.77
4) Acid Number (mg KOH/gm) : 3.65

Composition of Formation and Tube Well Water

Contents	Formation Water (ppm)	Tubewell water (ppm)
Carbonate	36	12
Bicarbonate	2244	219
Chloride	7543	390
Sulphate	38	38
Calcium	1323	160
Magnesium	1396	404
Iron	Traces	Traces
Sodium	3350	350
Potassium	210	4

Table-5

Variation in Oil Viscosity of Sand II

Well no.	Viscosity(cp)	GOR	Res. Oil Density (gm/cc)
No. 1	5.48	53	.8090
No. 3	7.35	43	.8191
No. 6	6.65	35.6	.8264
No. 7	4.81	46.8	.7989
No. 16	6.77	39.98	.8254
No. 44	18.25	29.64	.8484
No. 93	14.10	35	.8320

Table-6

Characteristics of Petroleum Sulphonates Used

Details-

	HLA	AOS	TRS-10-410
1) Name of Surfactant :	HLA	AOS	TRS-10-410
2) Nature of Surfactant :	Anionic	Anionic	Anionic
3) Molecular Weight :	450	440-450	415-430
4) Activity :	60%	38%	62.5%

Properties-

1) Thermal Stability : All samples thermally stable at 82 degree centigrade
2) Solubility : All samples are soluble in water and oil phase
3) CMC Value : 0.20 wt.%(active),HLA
   0.20 wt.%(active),AOS
   0.14 wt.%(active),TRS-10-410
4) IFT between Field X oil and tube well water having 0.20 wt.%(active) surfactant+1.0 wt.%. Na_2CO_3 : 10 milli-dynes/cm(HLA)
   15 milli-dynes/cm(AOS)
   1.0 milli-dynes/cm (TRS-10-410)

Table-7

(I). Selection & Optimisation of Alkali Concentration

IFT between crude oil and alkali at 82 degree centigrade -

Alkali conc.(wt%)	IFT(milli-dynes/cm)
0.0	2400
0.50	411
1.0	240*
1.50	252
2.0	291

*Optimum Alkali Concentration

(II). Selection & Optimisation of Surfactant Concentration

IFT between crude oil and various surfactants at 82 degree centigrade –

Surfactant conc.(wt%)	IFT milli-dynes/cm using HLA	IFT milli-dynes/cm using AOS	IFT milli-dynes/cm using TRS-10-410
0.10	94	221	2.8
0.15	51	120	Low
0.20	29	102	Low
0.30	50	171	Low

(III). IFT Reduction Through Alkali-Surfactant Blends

	IFT (milli-dynes/cm)		
	HLA	AOS	TRS-10-410
Na_2CO_3(1.0 wt%)+ Surfactant 0.20 wt%(active)	10	15	1.0

Table-8

Table-8

SL. NO.	PARAMETERS	EXPT-1	EXPT-2	EXPT-3	EXPT-4	EXPT-5	EXPT-6	EXPT-7	EXPT-8
1.	Type of core	Native # 183	Native #183	Native #115	Native # 115	Native # 183	Native # 183 # 115	Native # 183	Native # 183
2.	Length(cm)	7.8	7.8	7.8	7.8	7.8	20	7.8	7.8
3.	Diameter(cm)	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8
4.	Pore Volume(ml)	26	26	16	22	22	60	25.5	25.0
5.	Air Permeability (md)	5861	5238	4226	4616	4759	5912	5647	5540
6.	Absolute Water Permeability(md)	1428	1229	590	398	1268	1122	1578	1468
7.	Oil Saturation (%PV)	74.3	72.3	69.0	68.3	74.2	72.3	65.0	66.0
8.	Oil Permeability at irreducible Water sat.(md)	948	1087	382	310	1091	941	579	550
9.	Re-saturation (%PV)	74.1	72.31	69.0	69.5	74.2	-	65.0	-
10.	Injection Details								
	ASP Slug:	cont.	cont.	20%	25%	30%	25%	25%	25%
	(i) Alkali,Na2CO3	1.5	1.5	1.5	1.5	1.5	1.5	-	-
	(ii) Surfactant								
	(a) Type	HLA-1516	L-46	L-46	L-46	L-46	L-46	-	-
	(b) Conc.(%Active)	0.2	0.2	0.2	0.2	0.2	0.2	-	-
	(iii) Polymer Conc. Pusher-1000	1000	1000	1000	1000	1000	800	1000	800
	(iv) Viscosity of ASP slug(CP)	1.50	1.59	1.60	1.65	1.6	1.50	1.7	1.55
	Mobility Buffer (%PV)	-	-	30	30	30	30	30	30
	Average Conc.			600	600	600	400	600	400
11.	Oil Recovery								
	i) W/F(%OIIP)	43.4	40.4	43.9	43.0	43.5	38.0	43.6	43.8
	ii) ASP(%OIIP)	67.9	70.7	66.2	69.9	72.5	57.7	59.0	49.7
	iii) Over W/F	24.5	29.2	22.3	26.9	29.0	19.7	15.6	5.9
	iv) Stage	Sec.	Sec.	Sec.	Sec.	Sec.	Ter.	Sec.	TER.
12.	Water Perm. at ROS	12.78	11.51	-	-	14.18	-	29.2	10.0
13.	Mobility Ratio	4.5	3.5	-	-	3.5	-	3.9	

Results of ASP flood displacement experiments (Field X Sand S-II)

Table-9

Petrophysical Properties of the Pilot Wells

Well no.	Height Perforated(mtrs.)	Ø%	So%
6	8.5	21	57
45	7.0	22	70
52	9.0	22	70
90	6.0	24	51
118	5.5	24	62

Thickness Weighted Average Porosity = 22.27%
Thickness Weighted Average Saturation = 62.54%
Average Thickness = 7.2 mtrs.

Table-10

Pressure Data of the Pilot Wells

Well no.	Depth(mtrs.)	Initial Pressure(kg/cm^2)	Current Pressure(kg/cm^2)
6	1425	143	-
45	1415	142	94.4
52	1430	138	-
90	1430	132	105
118	-	-	102

Production Data of the Pilot Wells

Well no.	$Q_l(m^3/day)$	$Q_0(m^3/day)$	Watercut(%)	Np(MMt)
6	-	-	-	0.0397
45	72	17.3	77	0.1383
52	22	10.0	55	0.0129
90	-	-	-	0.0025
118	24	5.7	77	0.0671

Table-11

TABLE 11

Sl.	Injected fluid	Volume injected (m^3)	Injection rate (m^3/day)	Injection time (days)	Cum. Days	Chemical name	Requirement Daily (Kg/day)	Requirement Total (Tons)
1.	ASP (0·25PV)	48107	120	400·9	400·9	a). Na_2CO_3 b). Surf. c). Poly.	1799 240 96	721·6 96·2 38·5
2.	Mobility Buffer (0·30PV)							
	Slug I (600ppm)	19243	120	160·3	561·2	Poly.	72	11·54
	Slug II (400ppm)	19243	120	160·3	721·5	Poly.	48	7·69
	Slug III (200ppm)	19243	120	160·3	881·8	Poly.	24	3·84
3.	Chase water (0·55PV)	105835	150	705·6	1587·4	–	–	–

Pilot Life = 1587·4 days
(4.35 years = 4 years 4 months)

INJECTION SCHEDULE - INVETED 5 SPOT PATTERN

Table-12

Sampling Schedule-

Sl.no.	Type & Source of Sample	Sampling Frequency	Analysis Proposed
1.	ASP slug from storage each tank	Daily	Alkali, Surfactant, Polymer Concentration
2.	Mobility buffer of polymer solution from each tank	Daily	Viscosity at 82 degree centigrade and dissolved oxygen
3.	Polymer solution from injection well head	Daily	------do----------
4.	Water from pilot producers	Weekly	Salinity, Tracers, Surfactant, Alkali, Polymer.

- The sampling process is to be started at the inception of injection.
- The sampling schedule can be altered depending upon the pilot response.

Table-13

Cost Estimated of Sand II (Inverted 5-Spot Pattern)

Estimated Capital Cost	Rupees (lakhs)
1. Polymer Dispersion Unit Automatic Liquid/Dry Polymer Preparation & metering system	50.00
2. Injection pumps & flowmeters etc. (150 m^3/day and 80 m^3/day)	13.50
3. High Pressure Injection line @ Rs.3.50 lakhs/km. for 1 km	3.50
4. Cost of Surface Facilities (150 m^3/day)	53.00
Total Capital Cost	120.00 Lakhs

Break up of Surface Facilities Cost

Surface Facilities for Plant	Rs. In Lakhs
1.1* 100 m^3 Raw Water Tanks Epoxy Painted	12.00
2.2* 80 m^3 Polymer Tanks Rubber Lined and Alkali Tanks; 2*10 m^3	10.00
3.Transformer, HT Breaker, Cabling	8.00
4.Alkali & Surfactant Pumps	8.00
5.Filters, Piping, Civil works, Electrical Instt. & Mechanical Works including tube well	15.00
Total Surface Facilities	53.00 Lakhs

Table-14

A). Operational Cost (Rupees in Lakhs) – Year wise breakup

Sl.no.	Description	Year 1	Year 2	Year 3	Year 4	Year 5
1.	Manpower 3 nos. @Rs. 1.5 lakhs p.a. with 5%inc.	4.5	4.72	4.96	5.22	1.31
2.	Nitrogen Blanketing @Rs. 0.60 Lakhs/month	1.80	1.80	-	-	-
3.	Repair and Maintenance including Spares (% of capital)	1.69	1.69	2.53	2.53	0.63
4.	Power Cost	9.50	9.50	9.50	9.50	2.78
5.	Contingency(3% of Cap. + Opr.) per yr.	2.99	2.99	2.99	2.99	0.75
6.	Consultancy (5% of Capital)	6.0				
7.	Overhead(5% of Cap. + Operl.)	8.0				
	Total	35.48	20.7	19.98	20.24	5.47

Total Operating Cost = Rs. 101.87 Lakhs

B). Chemical Cost (Rs. In Lakhs)

Sl. No.	Chemicals	Year 1	Year 2	Year 3	Year 4	Year 5
1.	Petroleum Sulphonate @ Rs. 40/kg	35.1	3.4	-	-	-
2.	Polymer @ Rs. 200/kg	68.0	40.0	15.0	-	-
3.	Sodium Carbonate @ Rs. 10/kg	66.0	6.2			
4.	Oxygen Scavenger & Biocide		2			
5.	Tracer	5				
	Total	174.1	51.6	15.0		

Table-15

Estimated Oil Recovery Against Fluid Injection: One Inverted Five Spot Pattern: Sand II

Sl.no.	Injection Rate(m^3/day)	Type of Fluid	Total time (days)	Fluid PV(%)	Injected Total Volume(m^3)	Cumulative Oil Produced(m^3)
1.	120	ASP	160.4	0.10	19243	-
2.	120	ASP	320.8	0.20	38486	772
3.	120	ASP	400.9	0.25	48107	1986
4.	120	Polymer	481.1	0.30	58209	3861
5.	120	Polymer	641.5	0.40*	78094	9930
6.	120	Polymer	801.9	0.50	98139	14344
7.	120	Polymer	882.1	0.55	107761	15888
8.	150	Chase	946.2	0.60	117382	17323
9.	150	Chase	1074.5	0.70	127004	18647
10.	150	Chase	1203.0	0.80	146247	19750
11.	150	Chase	1331.1	0.90	165490	20633
12.	150	Chase	1459.4	1.00	194733	21405
13.	150	Chase	1587.7	1.10	213976	22067

Expected Breakthrough of ASP Chemicals : 21 months
Period of Completion of ASP slug : 13 months
Period of Completion of Polymer slug : 16 months
Period of Completion of Chase slug : 23 months Pilot life(total) : 4.35 years

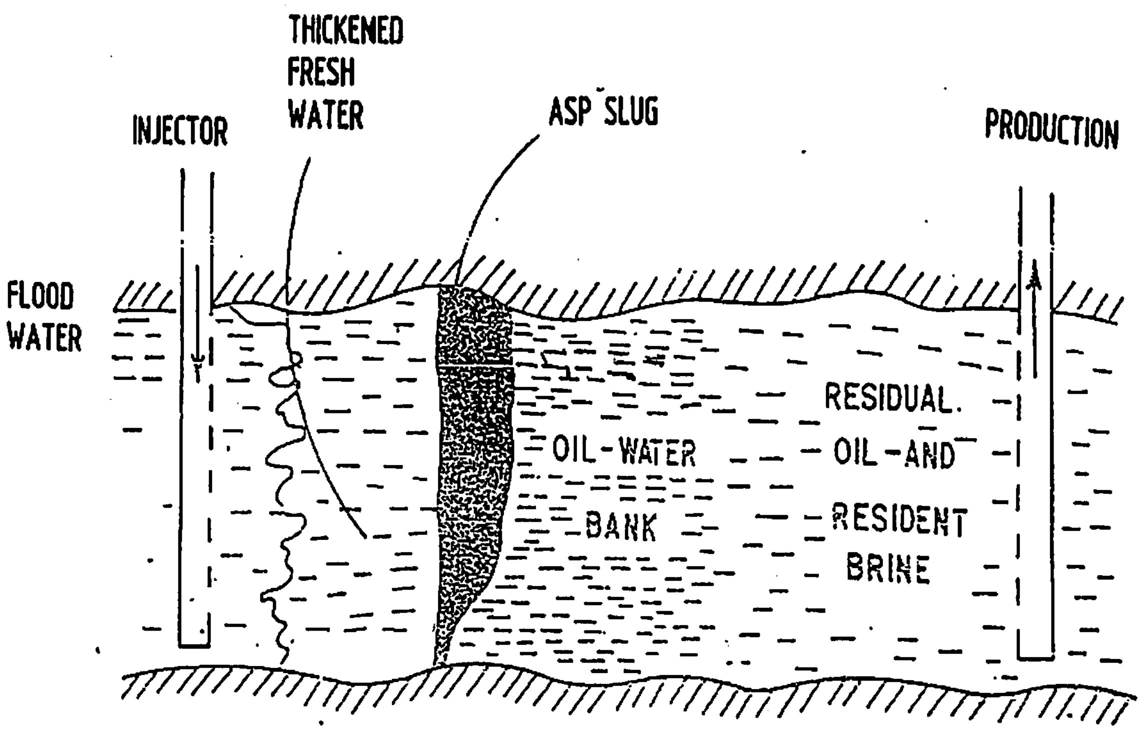
Figure-3.1

FIELD X COMPLEX

GENERAL STRATIGRAPHY OF PAY HORIZONS

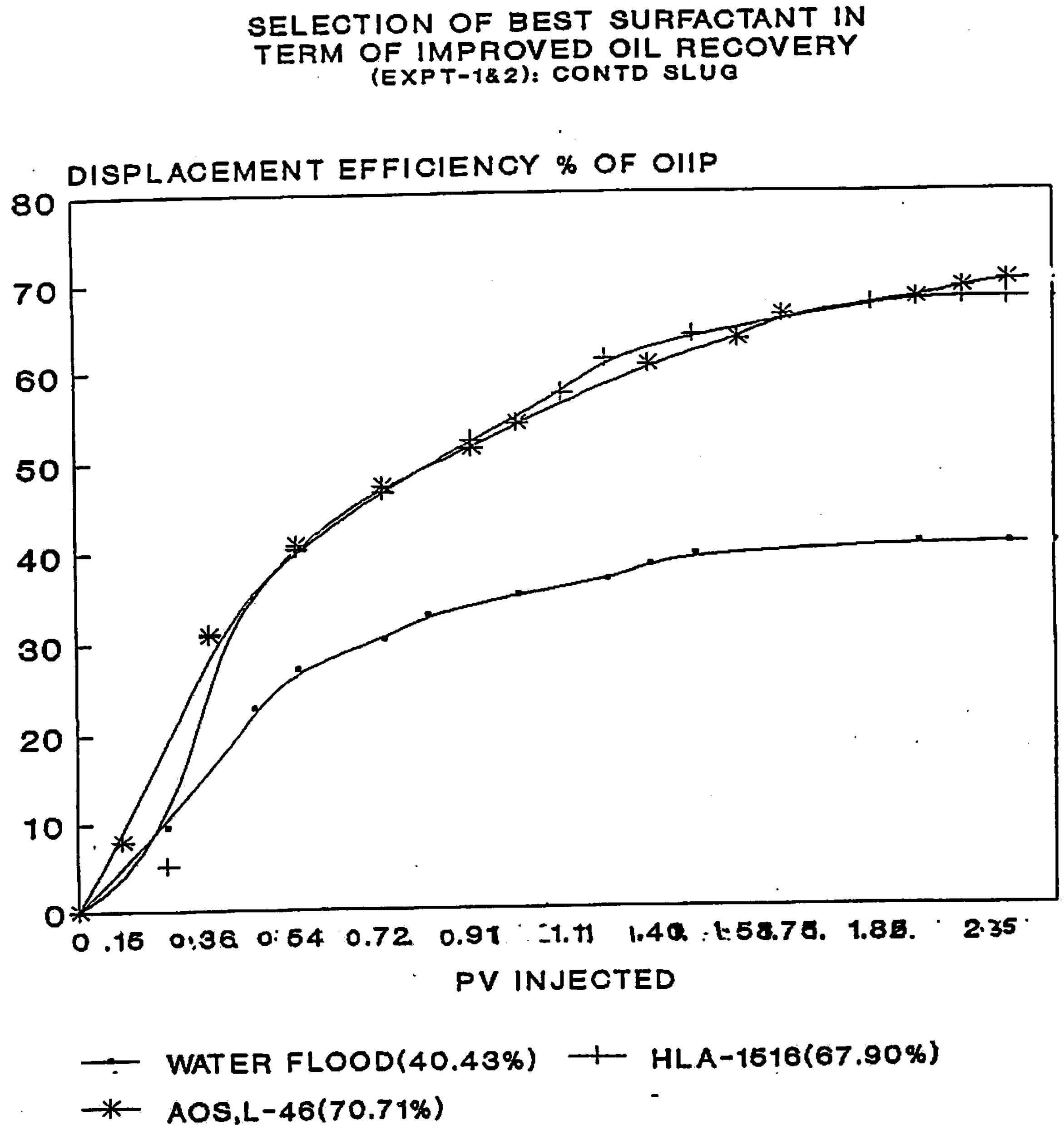
OLIGOCENE TO UPPER EOCENE	60-100		GREENISH SHALE WITH LITTLE SAND	
MIDDLE EOCENE	150-300		ALTERNATIONS OF COAL, SHALE AND SANDSTONES	
EARLY EOCENE	10-100		DARK GREY SHALE	
	50-200		SAND WITH COAL AND SHALE INTER-CALATIONS, SAND-WITCHED BETWEEN TWO COAL BEDS	Main Sands SI, SII, SIII
	10-40		DARK GREY SHALE	
	50-350		ALTERNATIONS OF SHALE AND FINE GRAINED SANDSTONES OR SILTSTONES	
	2100		DARK GREY OCCASIONALLY CARBONACEOUS SILTY SHALE	
PALAEOCENE	20-1500		TRAP CONGLOMERATES OCCASIONALLY WITH LAYERS OF CLAY STONE	
UPPER CRETACEOUS			BASALT, SOMETIMES WITH INTERTRAPPEANS	

Figure-3.2



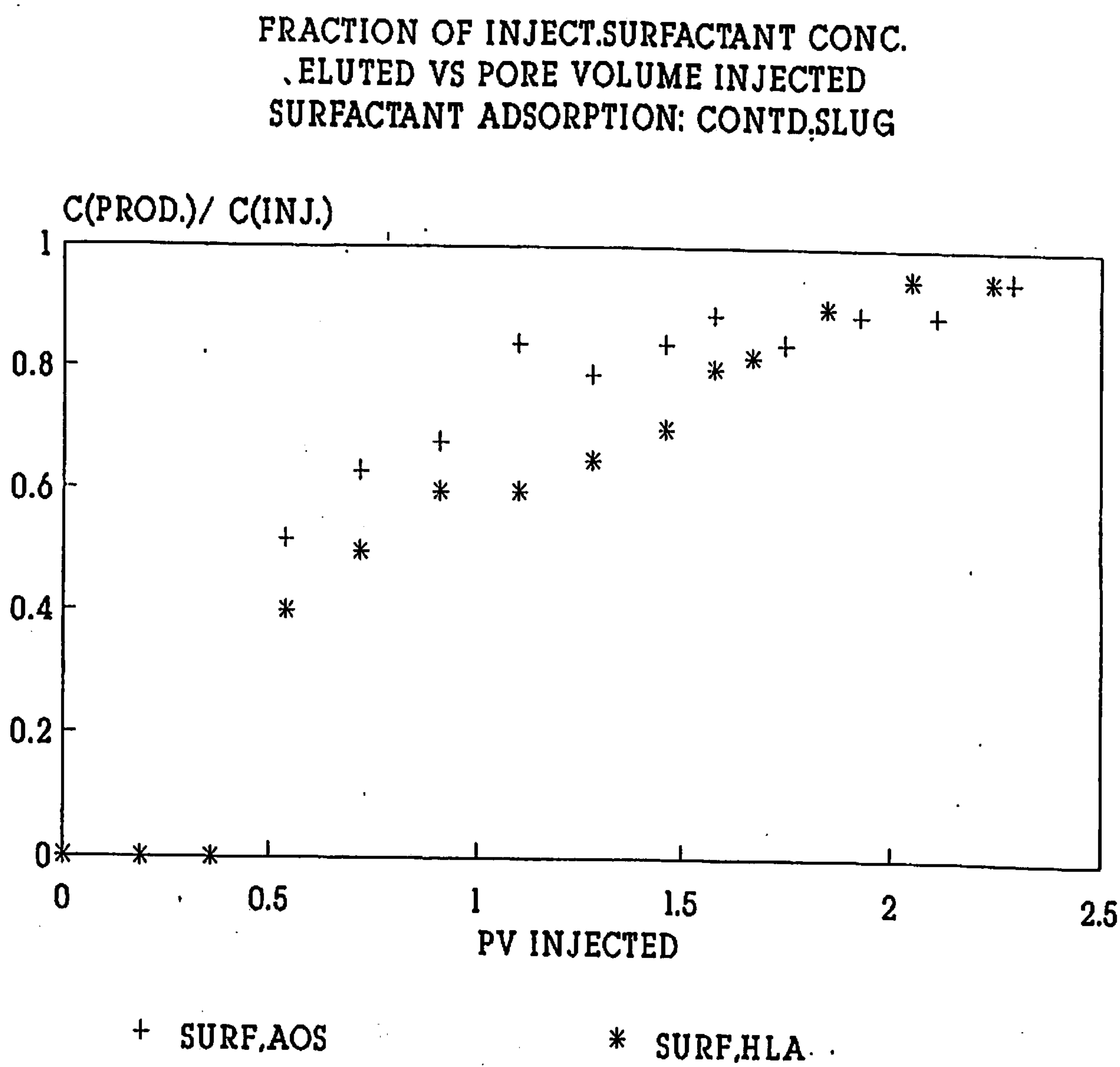
A schematic view of the ASP flood process

Figure-3.3



SELECTION OF BEST SURFACTANT IN
TERM OF IMPROVED OIL RECOVERY
(EXPT-1&2): CONTD SLUG
DISPLACEMENT EFFICIENCY % OF OIIP
80
70
60
50
40
30
20
10
0
0 .15 0.36 0.54 0.72 0.91 1.11 1.40 1.58.75. 1.88. 2.35
PV INJECTED
WATER FLOOD(40.43%)
HLA-1516(67.90%)
AOS,L-46(70.71%)

Figure-3.4



EXPERIMENT NO:1&2

Figure-3.5

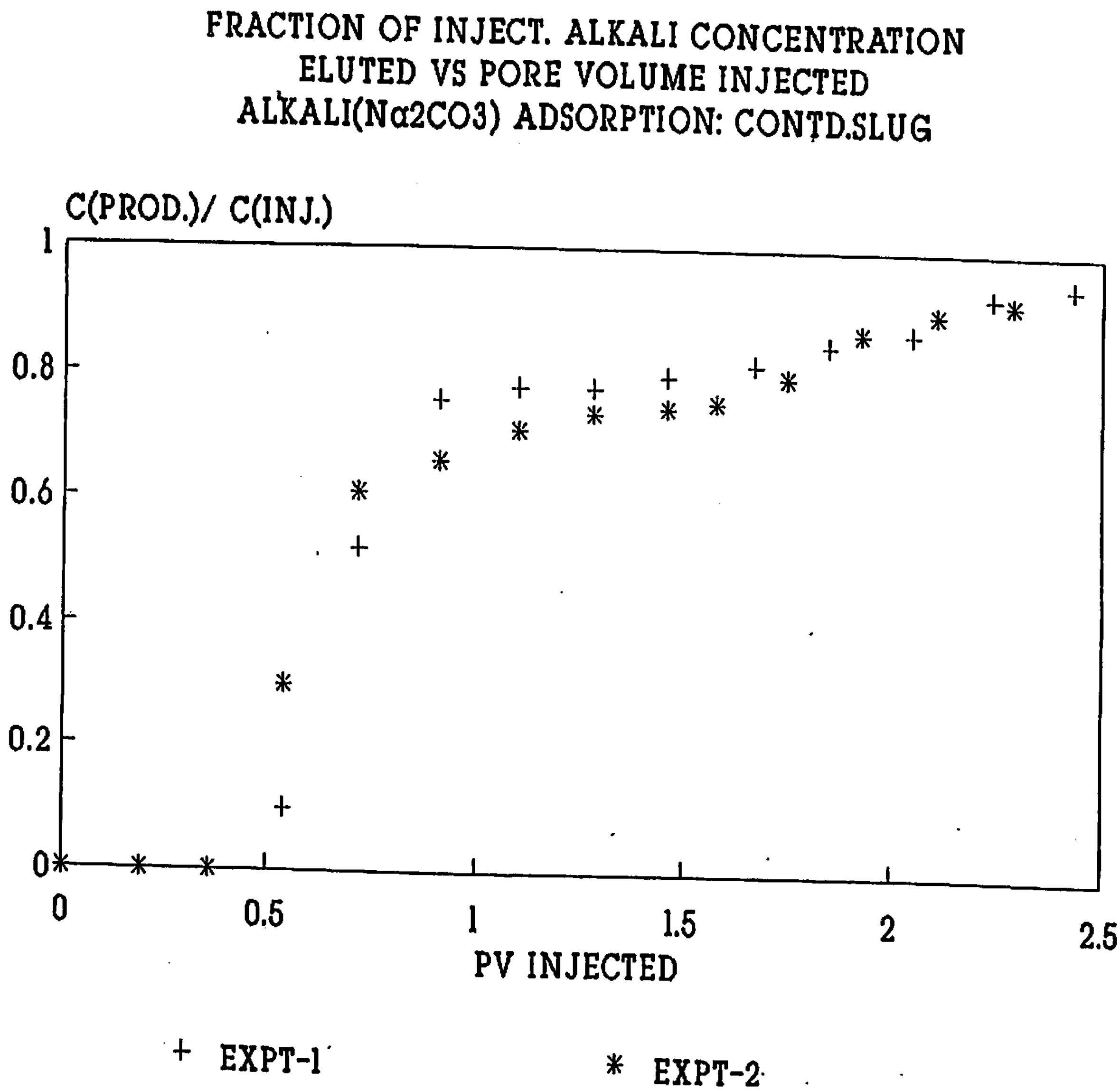

FRACTION OF INJECT. ALKALI CONCENTRATION
ELUTED VS PORE VOLUME INJECTED
ALKALI(Nα2CO3) ADSORPTION: CONTD.SLUG
C(PROD.)/ C(INJ.)
1
0.8
0.6
0.4
0.2
0
0
0.5
1
1.5
2
2.5
PV INJECTED
+ EXPT-1
* EXPT-2

Figure-3.6

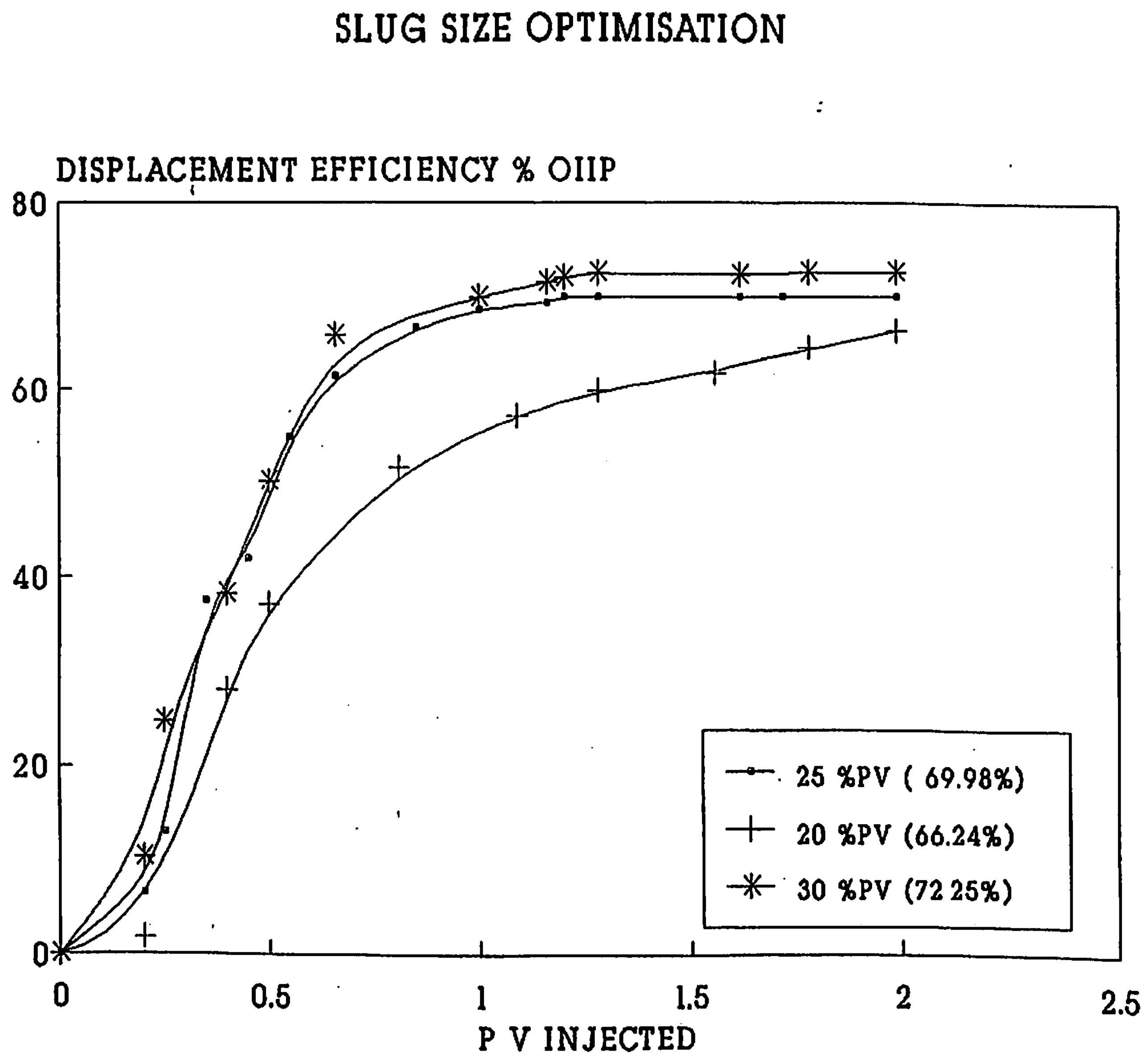
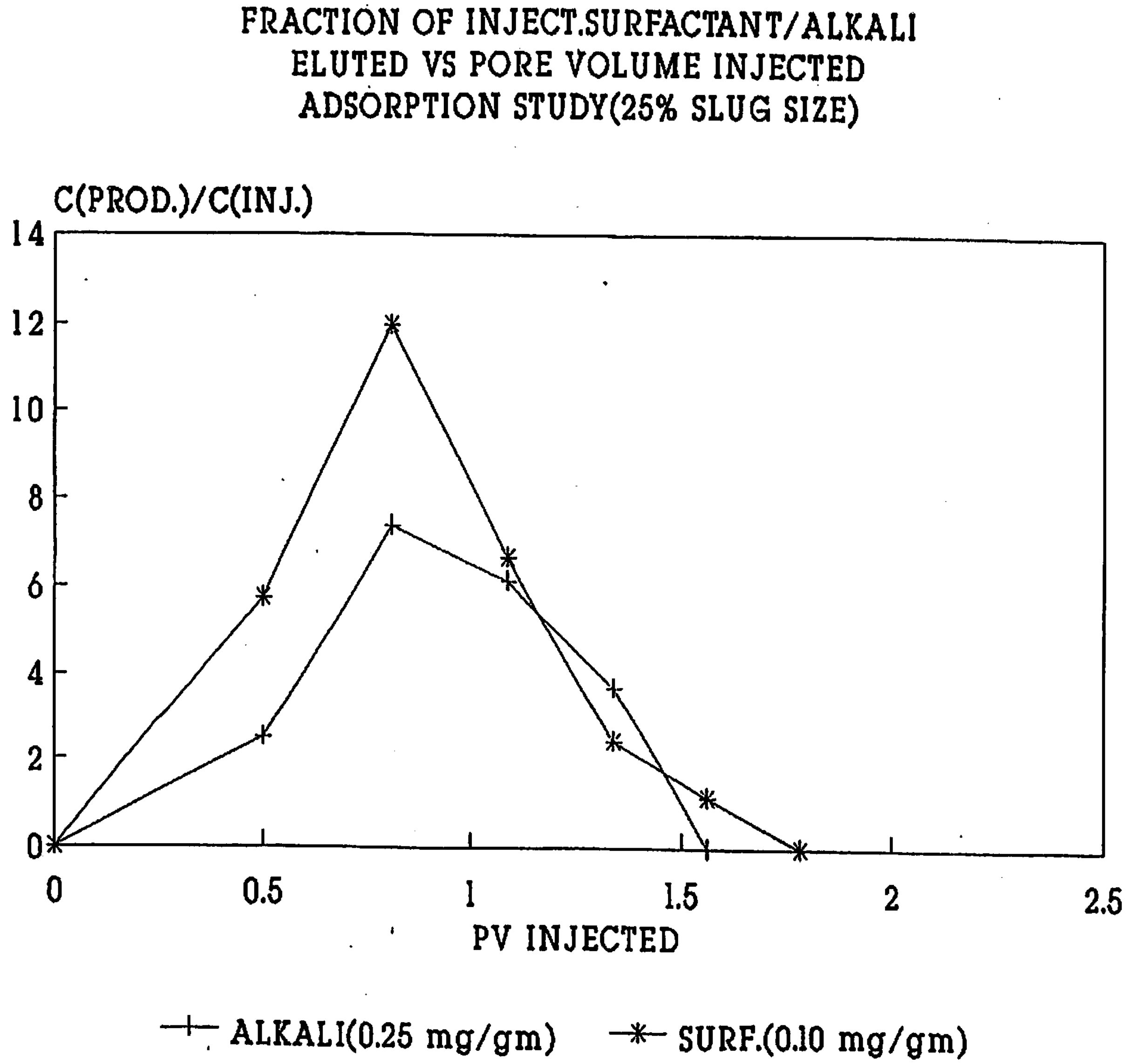

SLUG SIZE OPTIMISATION
DISPLACEMENT EFFICIENCY % OIIP
80
60
40
20
0
0
0.5
1
1.5
2
2.5
P V INJECTED
25 %PV (69.98%)
20 %PV (66.24%)
30 %PV (72 25%)

Figure-3.7



FRACTION OF INJECT.SURFACTANT/ALKALI
ELUTED VS PORE VOLUME INJECTED
ADSORPTION STUDY(25% SLUG SIZE)
C(PROD.)/C(INJ.)
14
12
10
8
6
4
2
0
0
0.5
1
1.5
2
2.5
PV INJECTED
ALKALI(0.25 mg/gm)
SURF.(0.10 mg/gm)

Figure-3.8

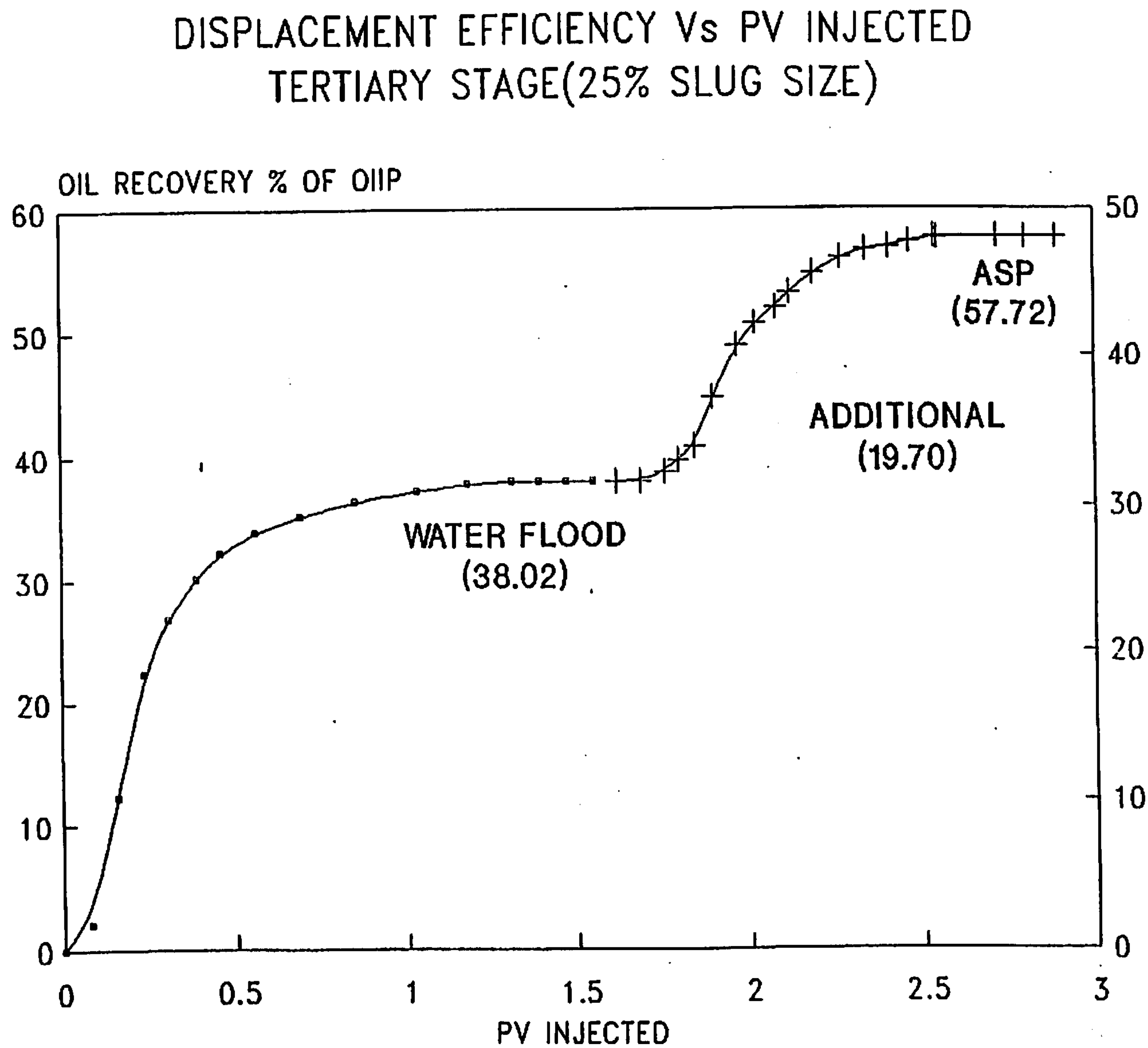

DISPLACEMENT EFFICIENCY Vs PV INJECTED
TERTIARY STAGE(25% SLUG SIZE)
OIL RECOVERY % OF OIIP
60
50
40
30
20
10
0
50
40
30
20
10
0
0.5
1
1.5
2
2.5
3
PV INJECTED
ASP
(57.72)
ADDITIONAL
(19.70)
WATER FLOOD
(38.02)

Figure-3.9

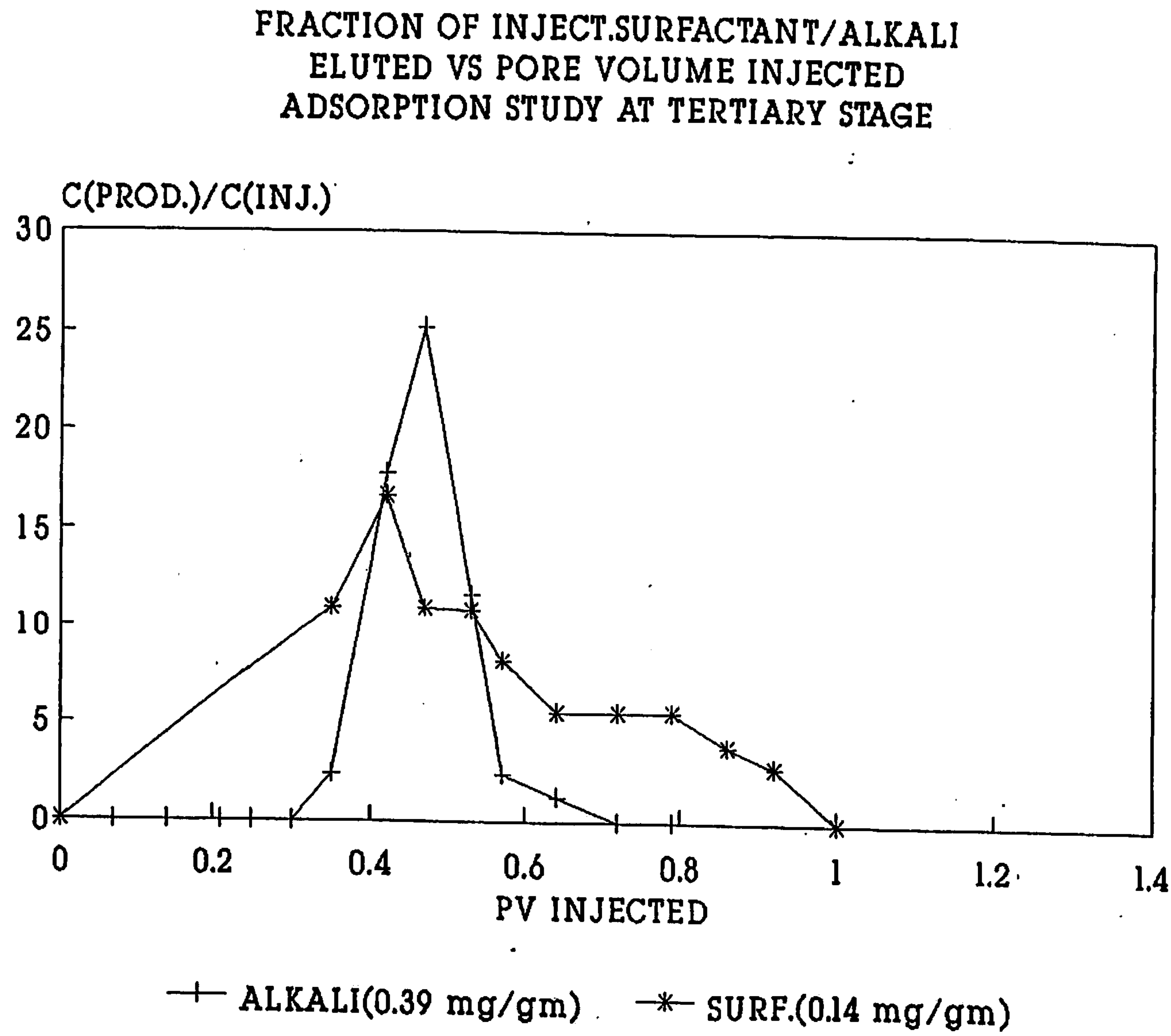
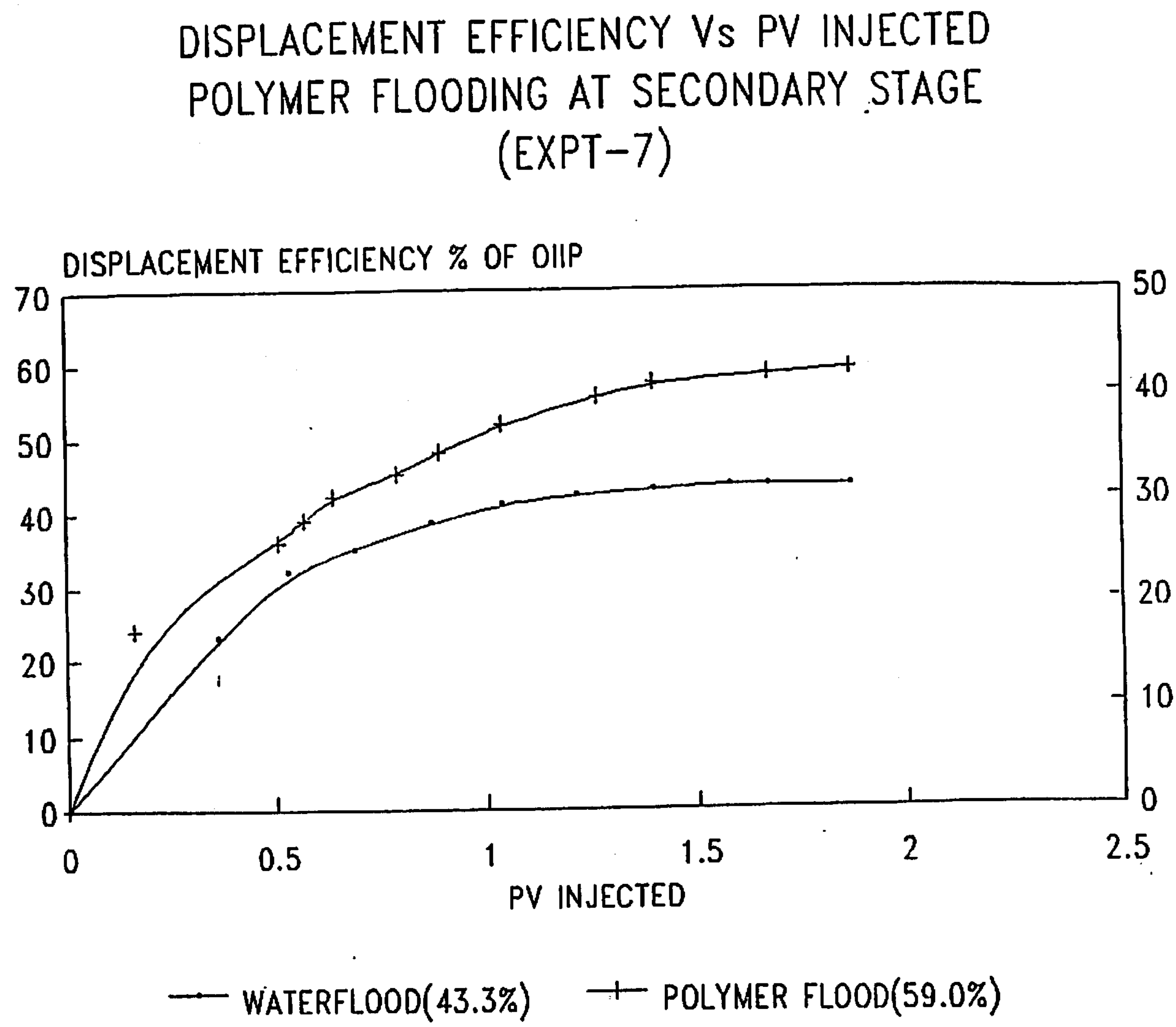

FRACTION OF INJECT.SURFACTANT/ALKALI
ELUTED VS PORE VOLUME INJECTED
ADSORPTION STUDY AT TERTIARY STAGE
C(PROD.)/C(INJ.)
30
25
20
15
10
5
0
0
0.2
0.4
0.6
0.8
1
1.2
1.4
PV INJECTED
ALKALI(0.39 mg/gm)
SURF.(0.14 mg/gm)

Figure-3.10



SLUG: 30%PV 1000 PPM
10%PV 800 PPM, 10% 600 PPM &
10%PV 600 PPM

Figure-3.11

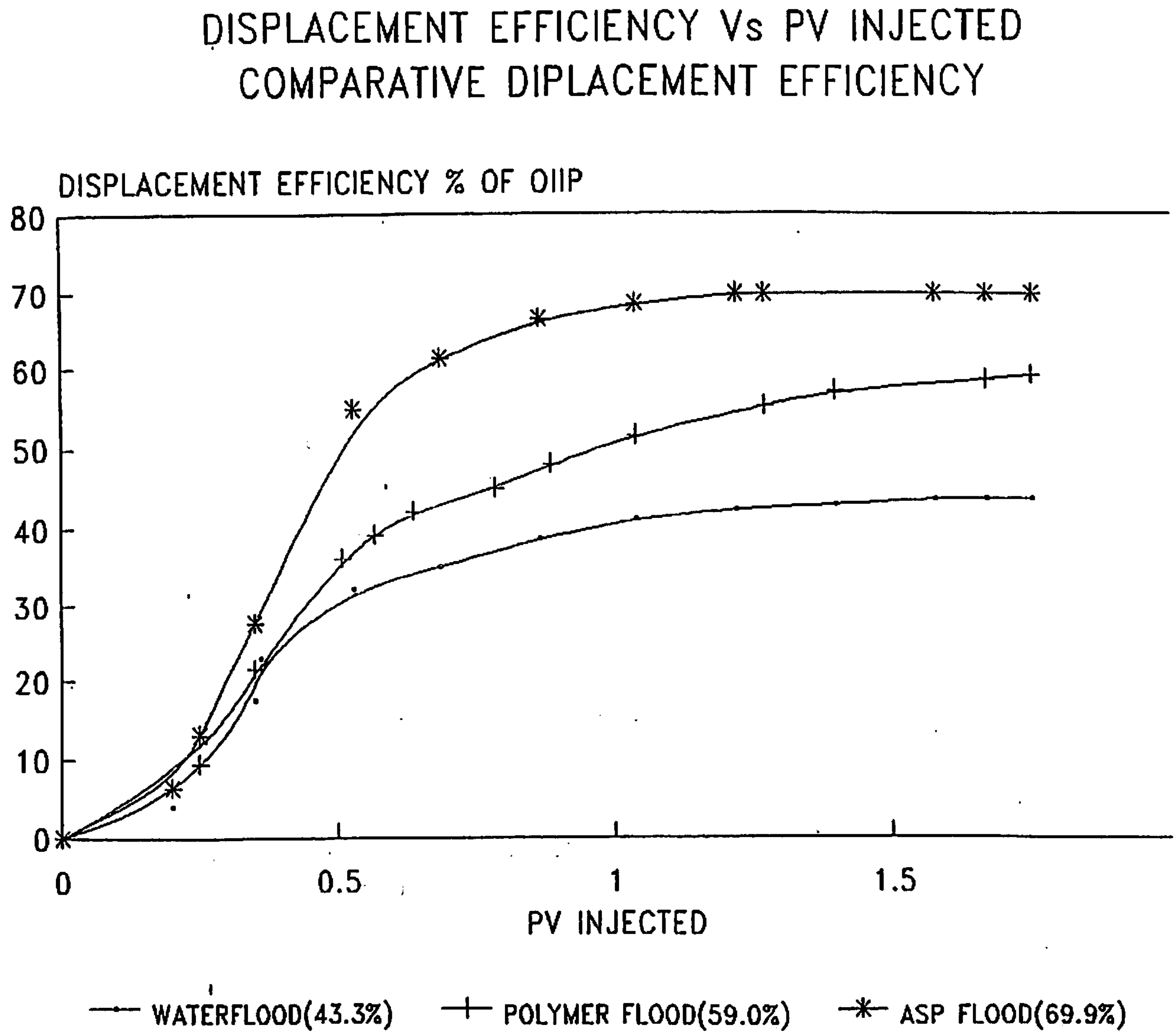

DISPLACEMENT EFFICIENCY Vs PV INJECTED
COMPARATIVE DIPLACEMENT EFFICIENCY
DISPLACEMENT EFFICIENCY % OF OIIP
80
70
60
50
40
30
20
10
0
0
0.5
1
1.5
PV INJECTED
WATERFLOOD(43.3%)
POLYMER FLOOD(59.0%)
ASP FLOOD(69.9%)

Figure-3.12

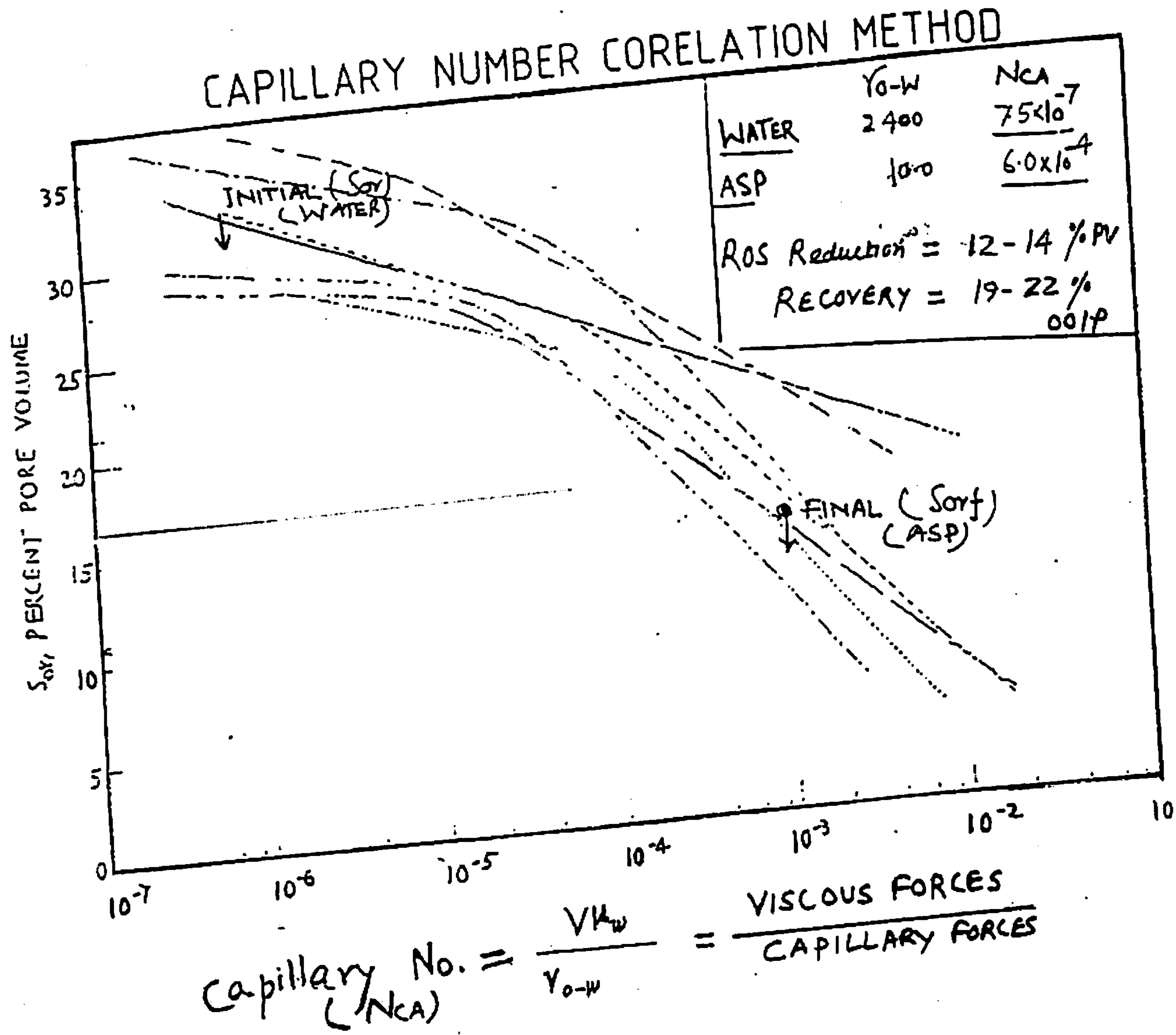


Figure drawn from various sample sources

Figure-3.13

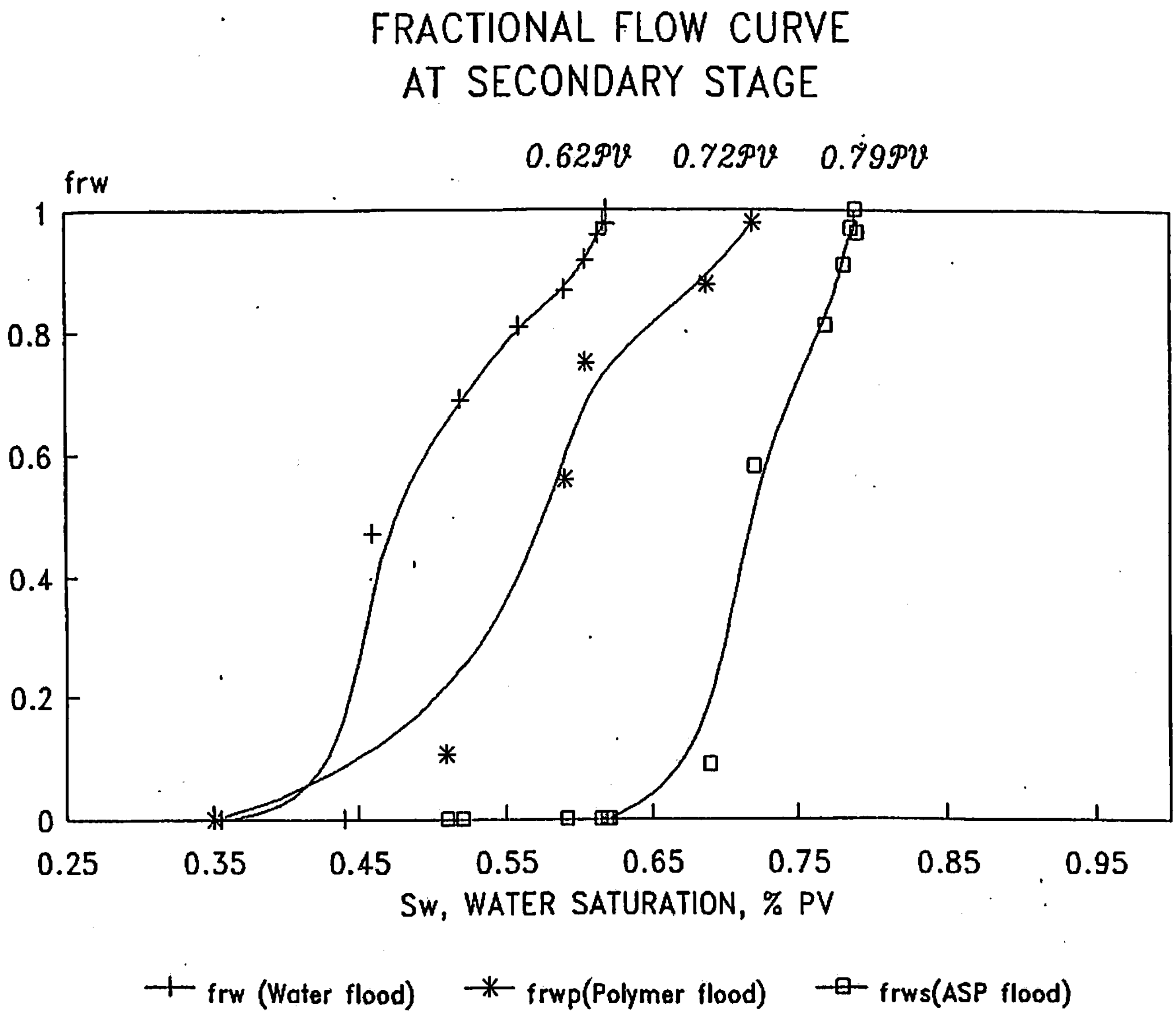

FRACTIONAL FLOW CURVE
AT SECONDARY STAGE
0.62PV 0.72PV 0.79PV
frw
1
0.8
0.6
0.4
0.2
0
0.25
0.35
0.45
0.55
0.65
0.75
0.85
0.95
Sw, WATER SATURATION, % PV
frw (Water flood)
frwp(Polymer flood)
frws(ASP flood)

Figure-3.14

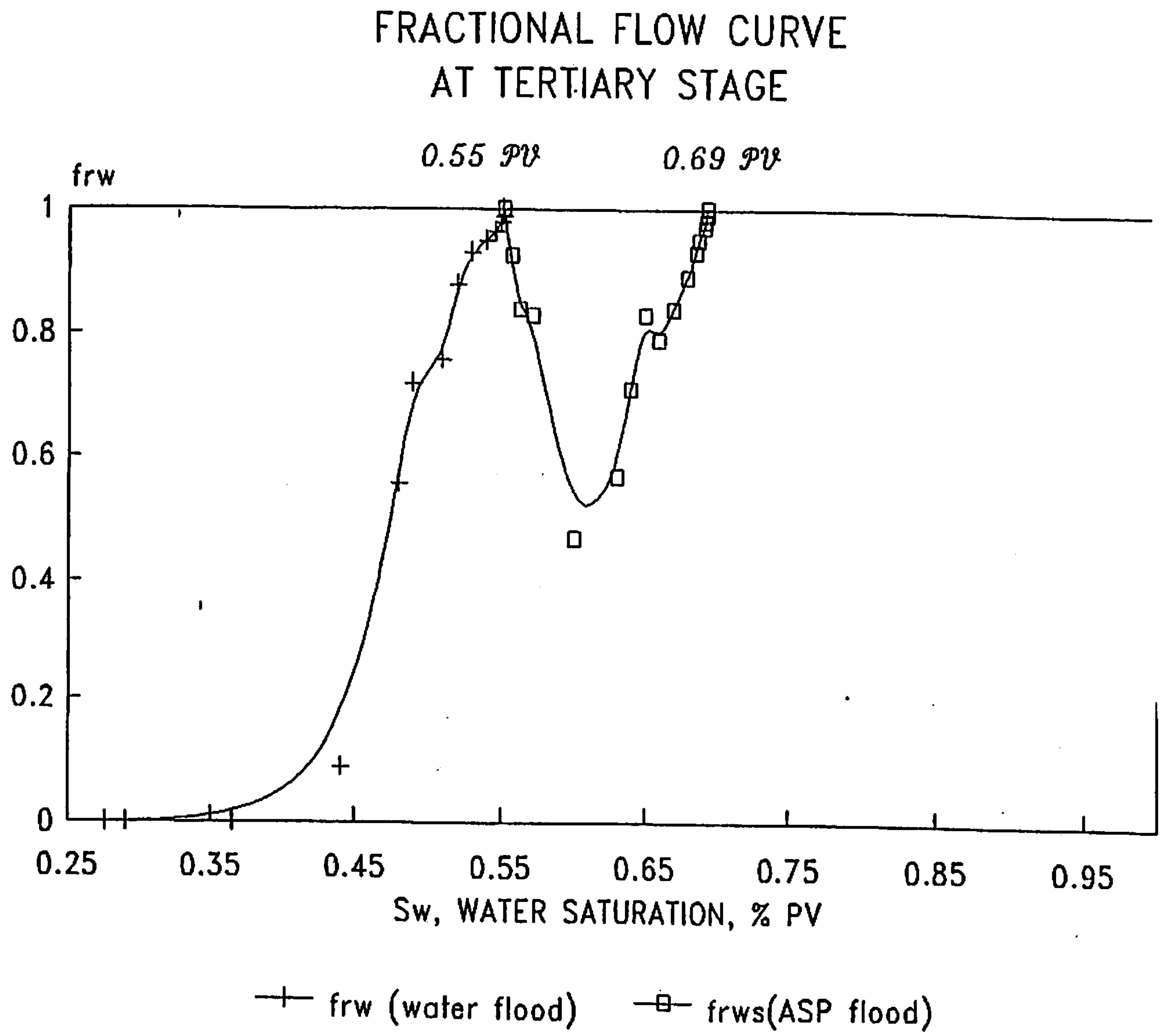

FRACTIONAL FLOW CURVE
AT TERTIARY STAGE
0.55 PV
0.69 PV
frw
1
0.8
0.6
0.4
0.2
0
0.25
0.35
0.45
0.55
0.65
0.75
0.85
0.95
Sw, WATER SATURATION, % PV
frw (water flood)
frws(ASP flood)

Figure-3.15

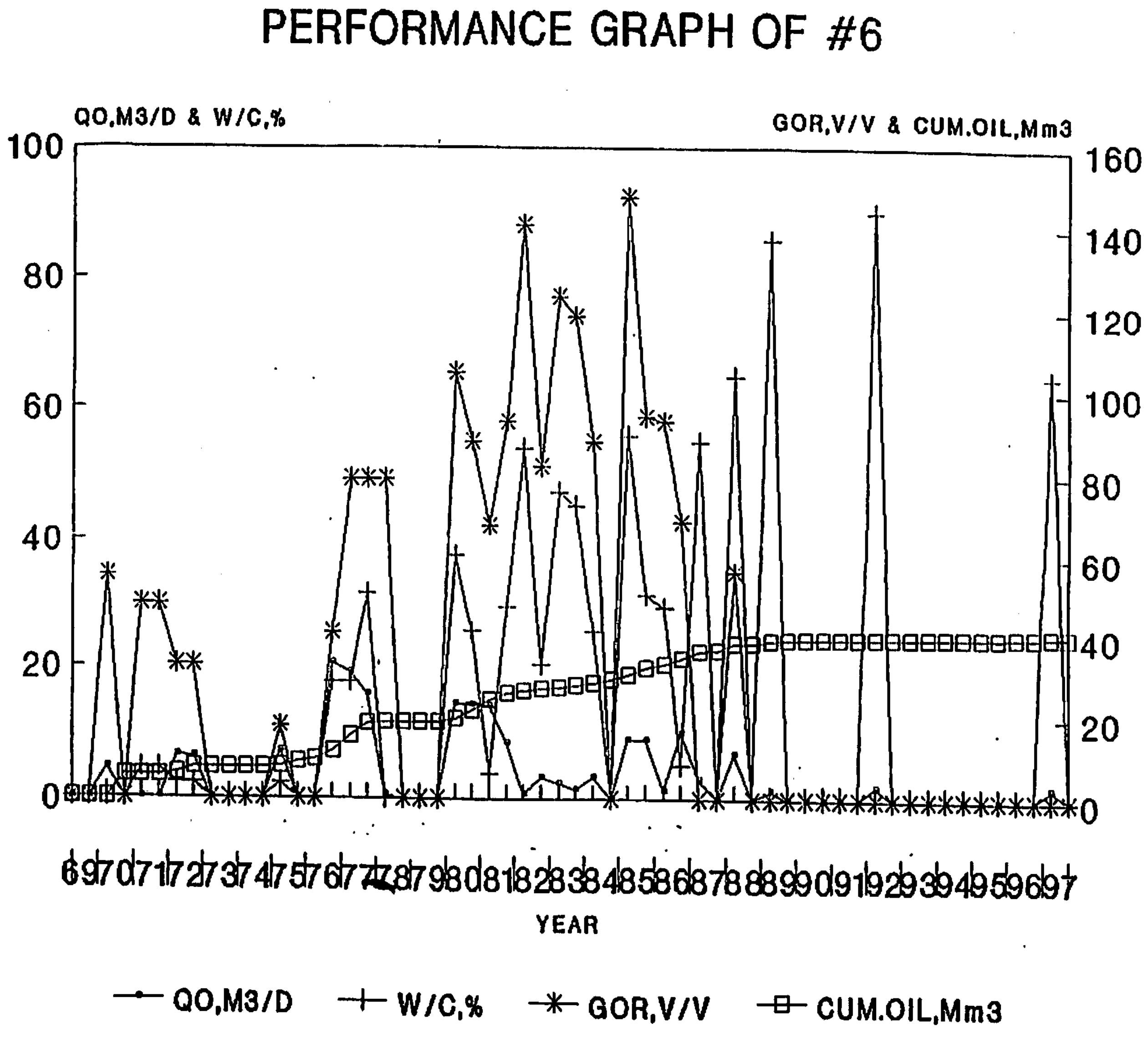
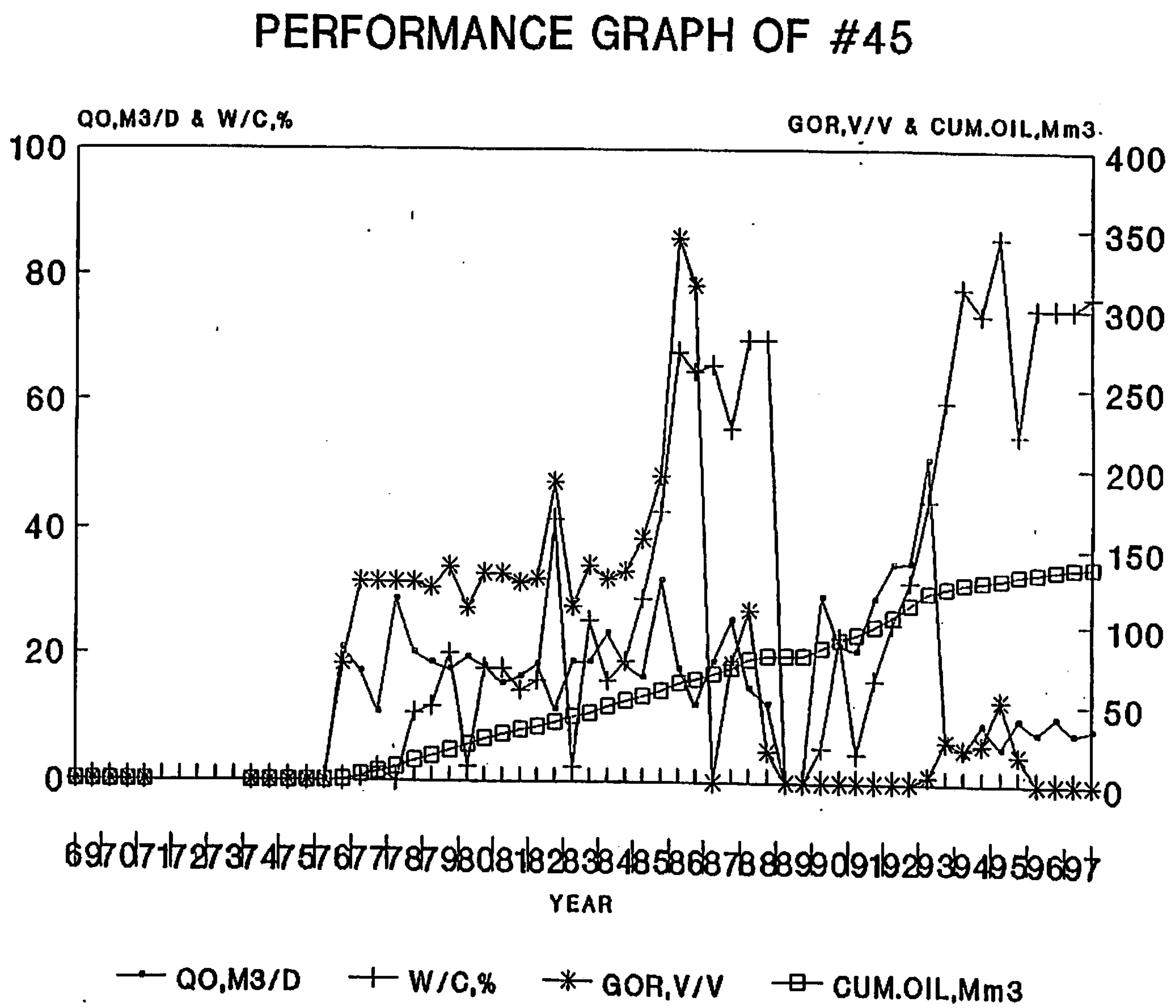
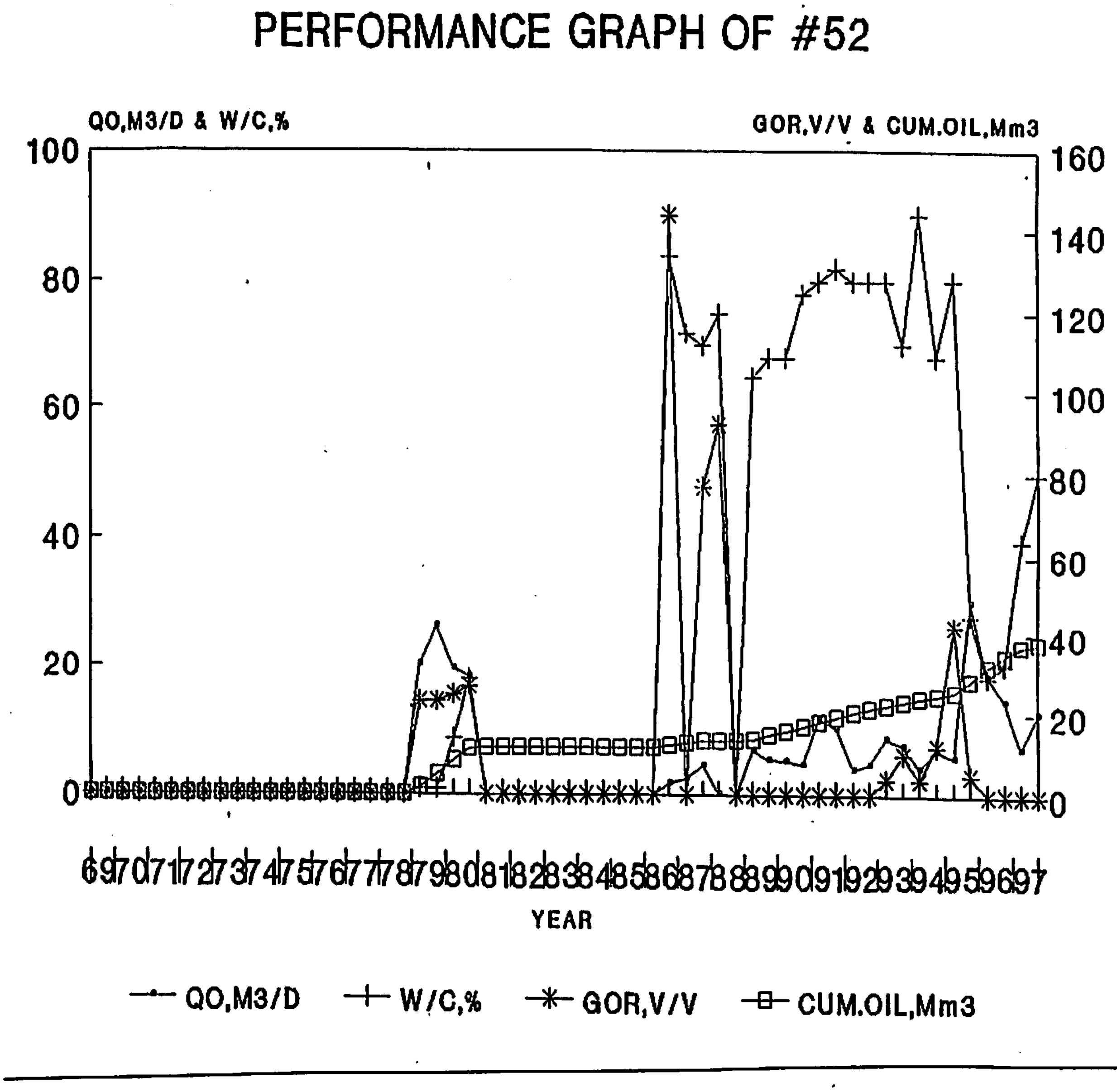

PERFORMANCE GRAPH OF #6
QO,M3/D & W/C,%
GOR,V/V & CUM.OIL,Mm3
100
80
60
40
20
0
160
140
120
100
80
60
40
20
0
YEAR
QO,M3/D
W/C,%
GOR,V/V
CUM.OIL,Mm3

Figure-3.16



PERFORMANCE GRAPH OF #45
QO,M3/D & W/C,%
GOR,V/V & CUM.OIL,Mm3
100
80
60
40
20
0
400
350
300
250
200
150
100
50
0
YEAR
QO,M3/D
W/C,%
GOR,V/V
CUM.OIL,Mm3

Figure-3.17



PERFORMANCE GRAPH OF #52
QO,M3/D & W/C,%
GOR,V/V & CUM.OIL,Mm3
100
80
60
40
20
0
160
140
120
100
80
60
40
20
0
YEAR
QO,M3/D
W/C,%
GOR,V/V
CUM.OIL,Mm3

Figure-3.18

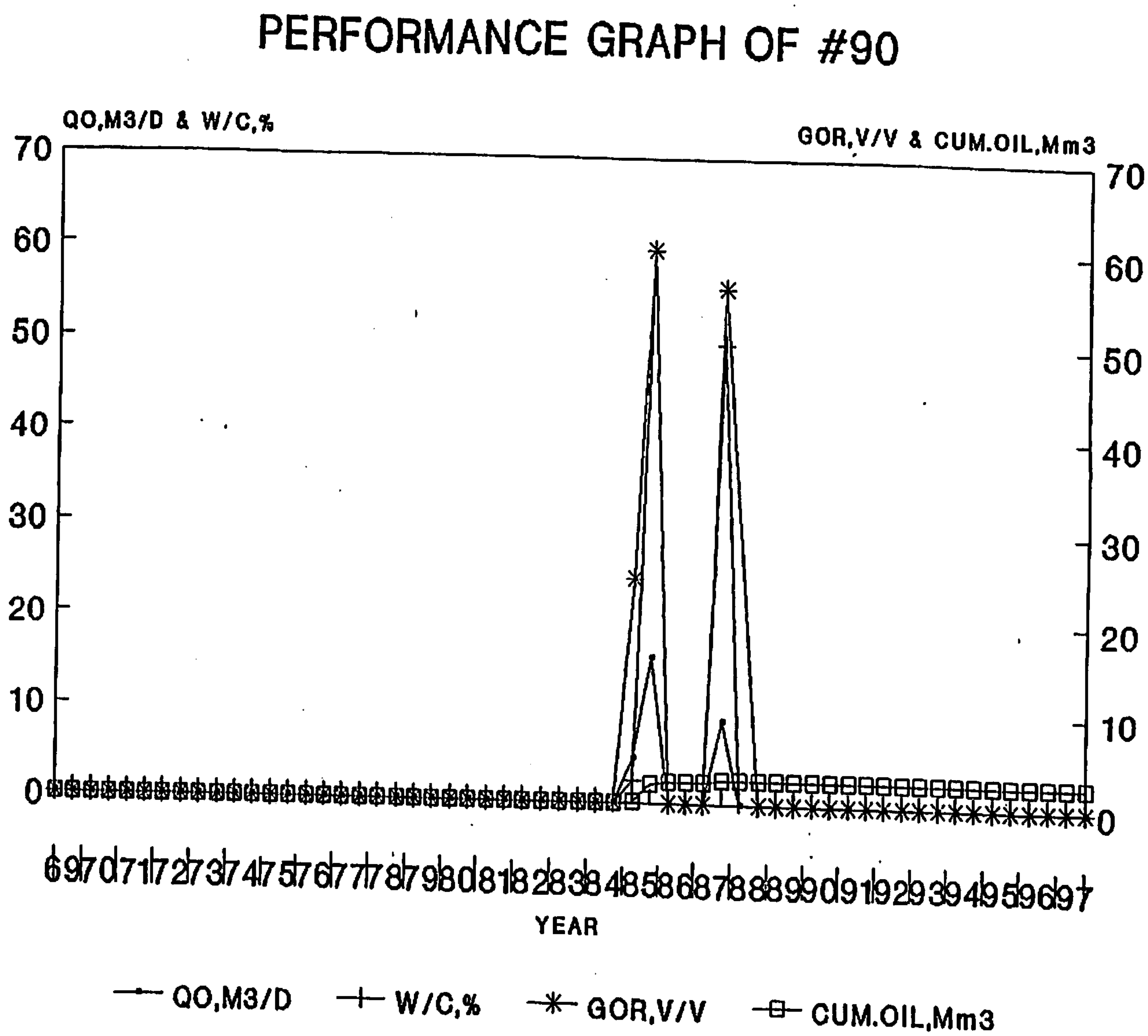

PERFORMANCE GRAPH OF #90
QO,M3/D & W/C,%
GOR,V/V & CUM.OIL,Mm3
70
60
50
40
30
20
10
0
YEAR
QO,M3/D
W/C,%
GOR,V/V
CUM.OIL,Mm3

Figure-3.19

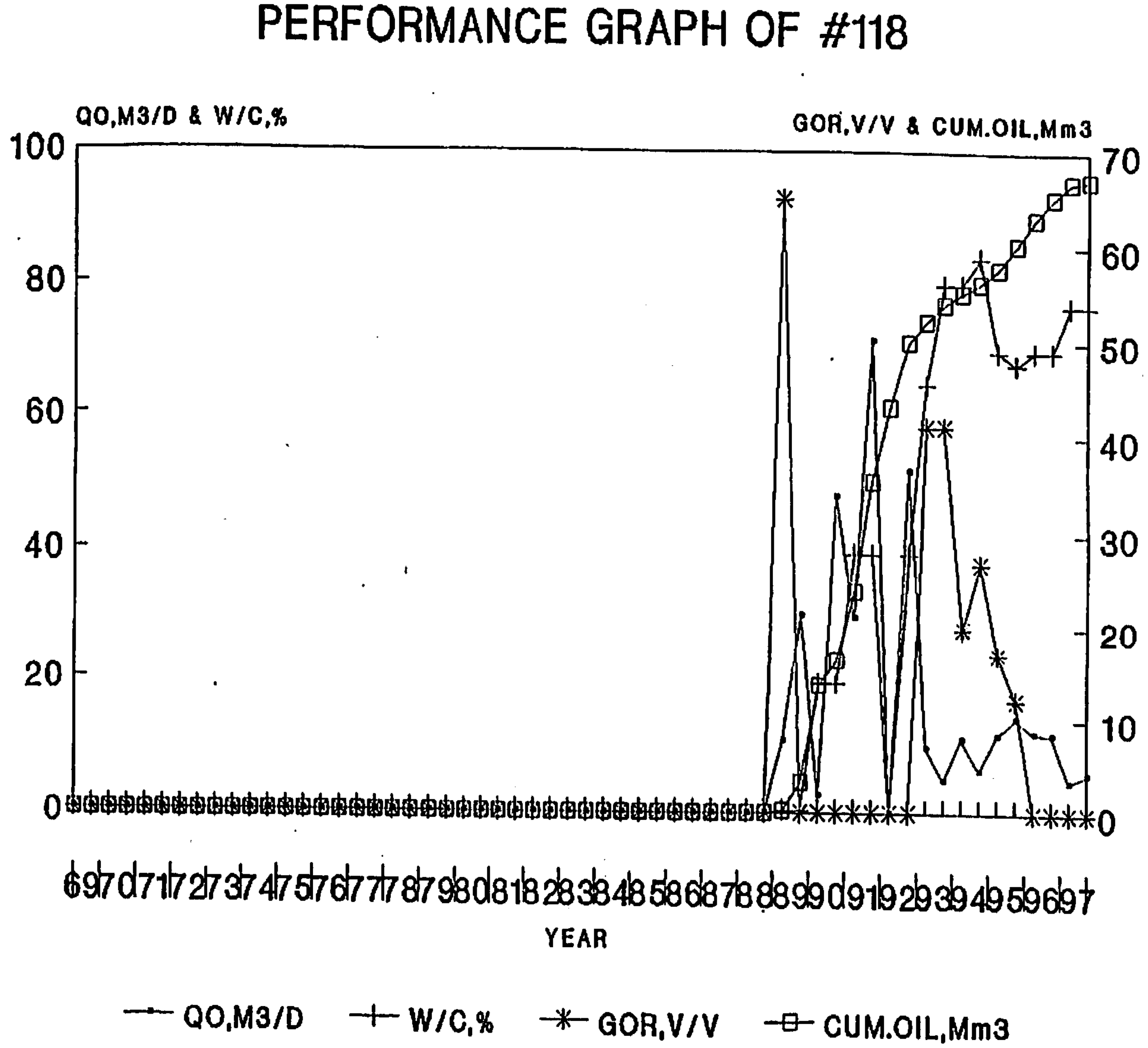
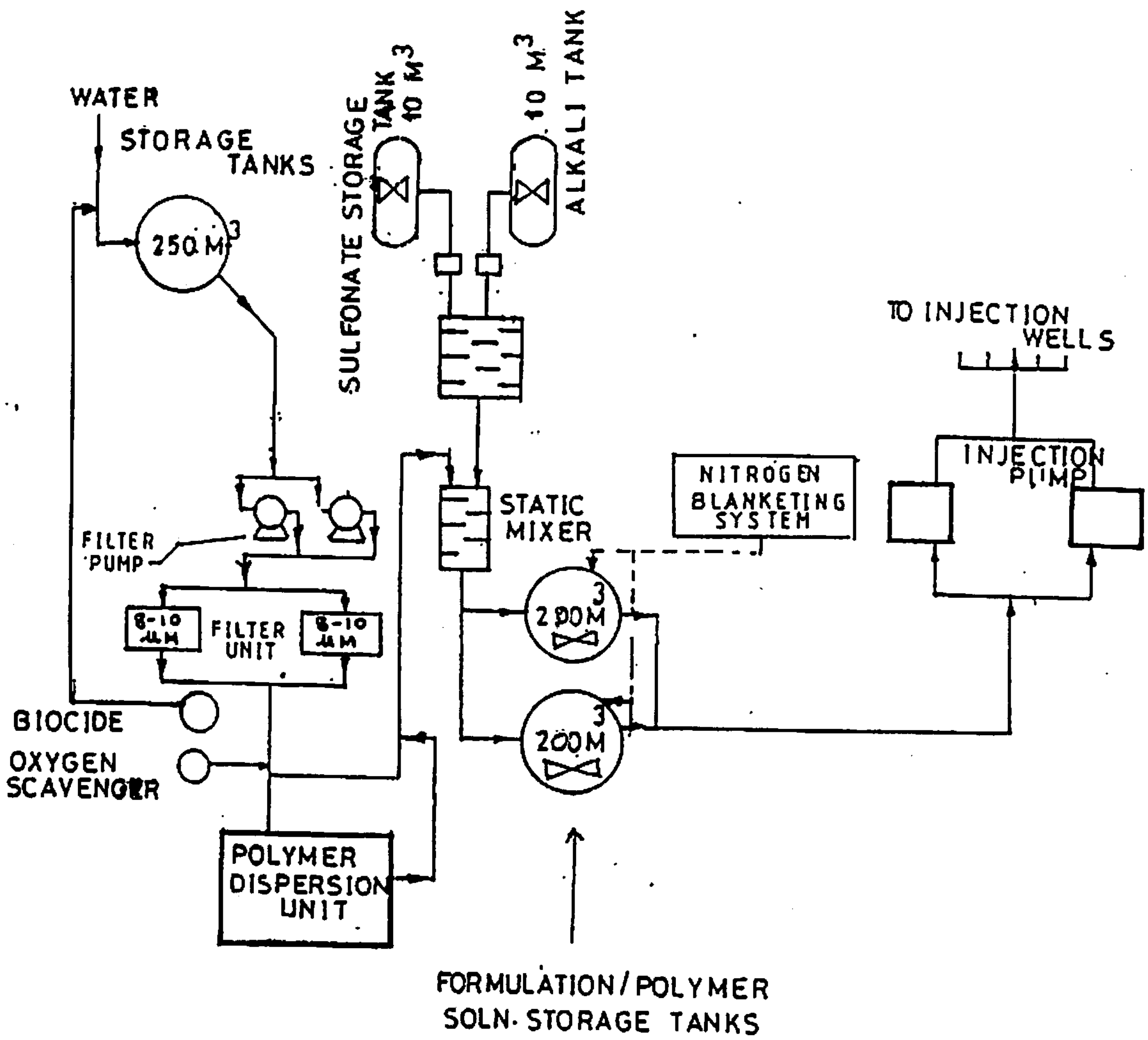

PERFORMANCE GRAPH OF #118
QO,M3/D & W/C,%
GOR,V/V & CUM.OIL,Mm3
100
80
60
40
20
0
70
60
50
40
30
20
10
0
YEAR
QO,M3/D
W/C,%
GOR,V/V
CUM.OIL,Mm3

Figure-3.20



FLOW DIAGRAM OF ASP FLOODING INJECTION PLANT

Figure 3.21-ASP Case History

ASP CASE HISTORY

	FIELD	COUNTRY	STAGE	INCRE. REC. (%OIIP)	REMARKS
1	WEST KIEHL	USA	FIELD-WIDE	20 %	SEC.
2	LIOYDMINISTER	CANADA	FIELD-WIDE	16 %	TERT.
3	GUDONG	CHINA	PILOT COMP.	11 %	TERT.
4	WHITE CASTLE	MEXICO	PILOT COMP.	20 %	TERT.
5	CAMBRIDGE	USA	PILOT PROG.	20 %	SEC.
6	DAQING	CHINA	PILOT PROG.	18.1 %	TERT.
7	CARAMAY	CHINA	PILOT PROG.		TERT.
8	ROMASKHINO	RUSSIA	FIELD-WIDE EXPANSION IN PROGRESS		

CASE STUDY OF SOME OTHER FIELDS

CHAPTER 4-

CASE STUDIES of SOME OTHER FIELD

4.1 Daqing Oil Field

This giant field was discovered in 1959. The reservoir is a lacustrine sedimentary deposit with multiple sand intervals. Reservoirs in various parts of the field are highly heterogeneous, with Dykstra-Parson indices greater than 0.5. The structure is a 90-mile-long, 6-mile-wide, and 2, 300- to 3, 900-ftdeep anticline trending north-northeast/south-southwest, with approximately 36 billion bbl OOIP. Chemical flooding has been implemented in 31 blocks in the Lamadian (L), Saertu (S), and Xinshugang reservoirs. Most of these reservoirs contain medium viscosity oils (approximately 9 cp at reservoir conditions) and low-salinity brines [5, 000 to 7, 000 ppm total dissolved solids (TDS)] with mild temperature (113°C).

ASP FLOODING-

It was recognized in the U.S. that certain alkaline agents would react with acidic crude oils to generate surfactants in situ to improve oil recovery. Normally, the requirement of minimum acids in the crude oil for the process to be effective is approximately 0.3 mg KOH/g of oil, although additional small amounts of surfactants (<0.5 wt%) and polymers could be added to the alkaline slug to improve the displacement efficiency and mobility control. Because there are several complex mechanisms in the ASP process, including the interfacial-tension (IFT) reduction, emulsification, and wettability alteration, each chemical/crude-oil system may have different controlling mechanisms that require different combinations of the ASP chemicals. In some cases, only alkaline and polymer (i.e., AP) chemicals were used, and in other cases, all ASP chemicals were necessary. The design of the ASP system in Daqing was based mainly on IFT reduction, although the role of emulsification in ASP flooding also was being studied. Because the acid contents are low (less than 0.1 mg KOH/g of oil) in the Daqing crude oil, more surfactants (>3%) were used in ASP pilot tests in Daqing.

4.1.1 ASP Flooding in Daqing Oil Field

Daqing had conducted 8 ASP pilot tests since 1994. A summary of these tests is given in Table 4.1.In this table, Slug 1 refers to a preflush with polymer, Slugs 2 and 3 usually are ASP slugs with different chemical compositions, and Slug 4 is the polymer drive. However, Slug 3 may not be used in some cases. The size of these tests varied from well spacing of 246 to 820 ft. Three of the tests are still ongoing. Sodium hydroxide was used in most of these tests, but sodium carbonate also was tried. Several types of surfactants, including alkyl benzene sulfonates, petroleum sulfonates, lignosulfonates, petroleum carboxylates, and biologically produced surfactants, were tested. Hydrolyzed polyacrylamide (HPAM) polymers with different MWs were used in the preflush, ASP slug, and driving slug. Incremental recovery efficiencies from the five completed projects varied from 19 to 25% OOIP.

Number	Location	Spacing (ft)	Wells (Injector/Producer)	Starting Date	Slug 1 (V_p)	Slug 2 (V_p)	Slug 3 (V_p)	Slug 4 (V_p)	Incremental Recovery (%OOIP)
ASP 1	S-ZX	348	4/9	September 1994	0.30	0.29			21.40
ASP 2	X5-Z	462	1/4	January 1995	0.30	0.30	0.18		25.00
ASP 3	X2-X	656	4/12	September 1996	0.04	0.35	0.10	0.25	19.40
ASP 4	S-B	246	3/4	December 1997	0.33	0.15	0.25		23.24
ASP 5	B1-FBX	820	6/12	March 1997	0.30	0.15	0.20		20.63

Table -4.1

4.2 B1-FBX Large Spacing ASP Pilot Test

This field test was conducted in 1997 to evaluate the performance of the ASP process in larger-well-spacing operations. There were six injection wells and 12 producing wells. The recovery efficiency of this test was 22% OOIP, with a maximum water cut reduction from 90 to 50%, as shown in Fig 4.1.

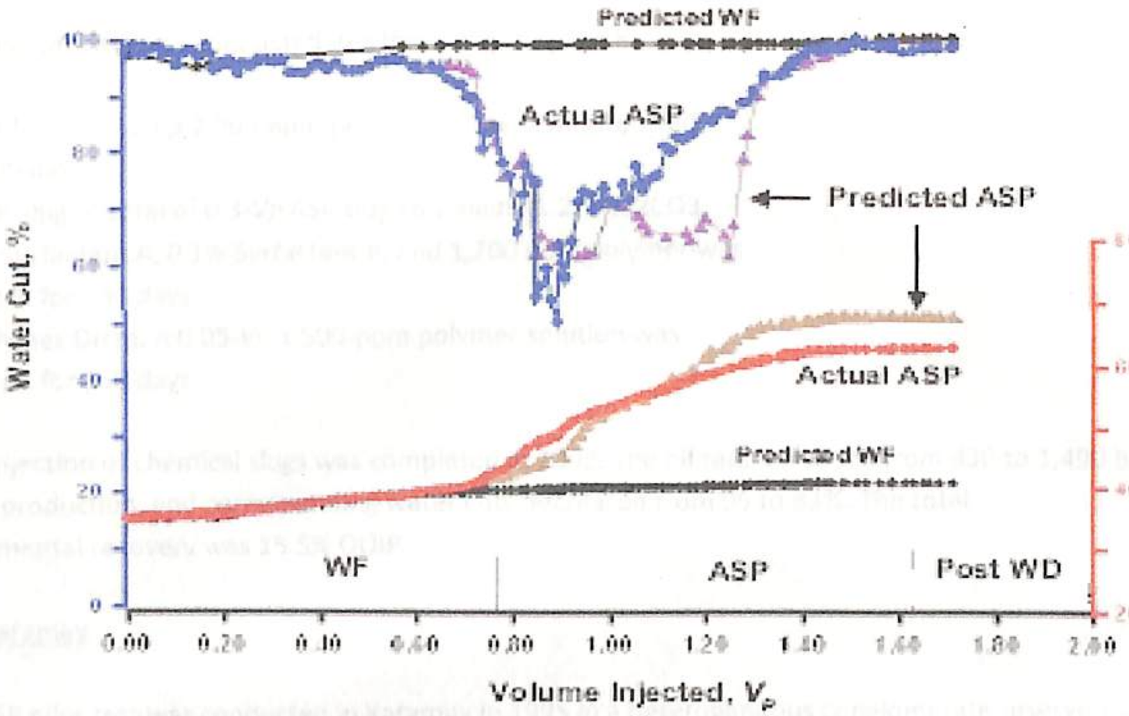


Figure 4.1-FBX ASP pilot test results (central producing wells)

4.3 XII-Z Commercial-Scale ASP Test

A larger multi pattern large well- spacing ASP-flooding test with 17 injection wells and 27 producing wells was conducted in 2001 in the S reservoir. Results through 2004 showed that the recovery efficiencies were 13.4% OOIP in the eastern part of the test area with better reservoir connectivity and 8.4% OOIP in the western part of the test area with poorer connectivity. Estimated final recovery efficiency in the eastern area could reach 18%. Results from two other tests are not yet available. Although the current oil production from ASP flooding is small, Daqing expects to replace the oil production from PF with ASP flooding beyond 2010. Estimated long-term ASP-flooding potential would double that of PF. Three more commercial-scale tests with multiple patterns are being planned.

4.4 Testing the ASP Process in Other Oil Fields

In addition to the tests conducted in Daqing, the ASP process was tested in other fields including Shengli, Karamay, and Liaohe. Here is discussed only ASP tests conducted in Shengli and Karamay. *Shengli.* Shengli started experimental research in ASP flooding in the early 1980s, and the first small-well-spacing field test began in 1992 in the Gudong reservoir. Incremental recovery was reported to be 26% OOIP. The second ASP pilot test was conducted in 1997 in the western part of the Gudao reservoir in an area of 150 acres. The well spacing and net pay were 695 ft and 53 ft, respectively. The reservoir is a channel-sand deposit with average porosity and permeability of 32% and 1,520 md, respectively. The pilot area has six injection wells and 10 producing wells with an average daily oil rate of 46 B/D. The WF recovery efficiency was 22.4% OOIP before ASP flooding.

The ASP process was conducted in a three-slug sequence.

1. Preflush: A 0.1-*Vp* 2,000-ppm polymer solution was injected for 306 days.
2. ASP Slug: A total of 0.3-*Vp* ASP slug containing 1.2% Na2CO3, 0.2% Surfactant A, 0.1% Surfactant B, and 1,700 ppm polymer was injected for 948 days.
3. Polymer Drive: A 0.05-*Vp* 1,500-ppm polymer solution was injected for 158 days.

The injection of chemical slugs was completed in 2002. The oil rate increased from 630 to 1,490 B/D at peak production, and corresponding water cuts decreased from 96 to 83%. The total incremental recovery was 15.5% OOIP.

4.5 Karamay

An ASP pilot test was conducted in Karamay in 1995 in a heterogeneous conglomerate reservoir with a well spacing of 164 ft and four five-spot patterns.10 A three-slug process was designed as follows.

1. A 0.40-*Vp* slug of 1.5% NaCl brine preflush.
2. A 0.34-*Vp* slug of ASP containing 1.4% Na2CO3, 0.3% crudeoil sulfonates, and 0.13% polymer.
3. A 0.15-*Vp* slug of 0.1% polymer and a 0.4% NaCl drive fluid.

The WF recovery efficiency in the pilot area before ASPslug injection was approximately 50% OOIP at 99% water cut. The ASP slug was injected from July 1996 to June 1997 with continued waterdrive to early 1999. The increased recovery started after approximately 0.04 *Vp* of the ASP slug had been injected and peaked when approximately 0.2 *Vp* of the ASP slug had been injected, with a six-fold increase in oil rate and water-cut reduction from 99 to 79%. Incremental recovery in the central well was 25% OOIP. Severe emulsions in produced fluids were observed, and difficulties were encountered in breaking the emulsions.

4.6 Conclusions From the ASP Pilot Tests

1. It was proved that >20% OOIP incremental recoveries can be obtained with the ASP process, but higher polymer concentrations are needed for effective mobility control.
2. ASP slugs with alkaline concentrations >1.0%, surfactant concentrations of approximately 0.3%, and polymer concentrations >1,500 ppm are effective in most tests conducted in China.

3. Small-scale tests appear to be more effective than large-scale tests because of reservoir heterogeneity and chromatographic separation of chemicals in the displacement process.
4. Better ASP systems need to be developed with more cost effective surfactants in weak alkaline systems and with pH-tolerant polymers.
5. Optimization of the ASP slug; better understanding of the in-situ chemical transport and displacement mechanisms; cost effective solutions to scale, emulsion, and other produced-fluid treatment; and a better descriptive model are needed.
6. The large-scale, field wide expansion has not been implemented in China because of the high cost of the chemical system, the potential injection and production problems, and lack of fully optimized chemical systems.

ASP Pilot Lawrence field Illinois

Plains, Illinois, Inc. was funded in 2000 by the U.S. Department of Energy to evaluate alkaline-surfactant-polymer (ASP) flooding in the Cypress and Bridgeport reservoirs of Lawrence field in southeast Illinois (Figure 4.2). ASP enhanced oil recovery (EOR) has proven to be economic only as incremental recovery in mature water flooded fields in Illinois. Lawrence field at 96 years old was reaching a "now or never point" in development with an estimated 40 to 70% of OOIP remaining in place. The ASP flood is designed to target the residual oil and maintain long term cash flow for Lawrence field. Plains, Illinois partnered with the Illinois Geological Survey for all technology transfer activities.

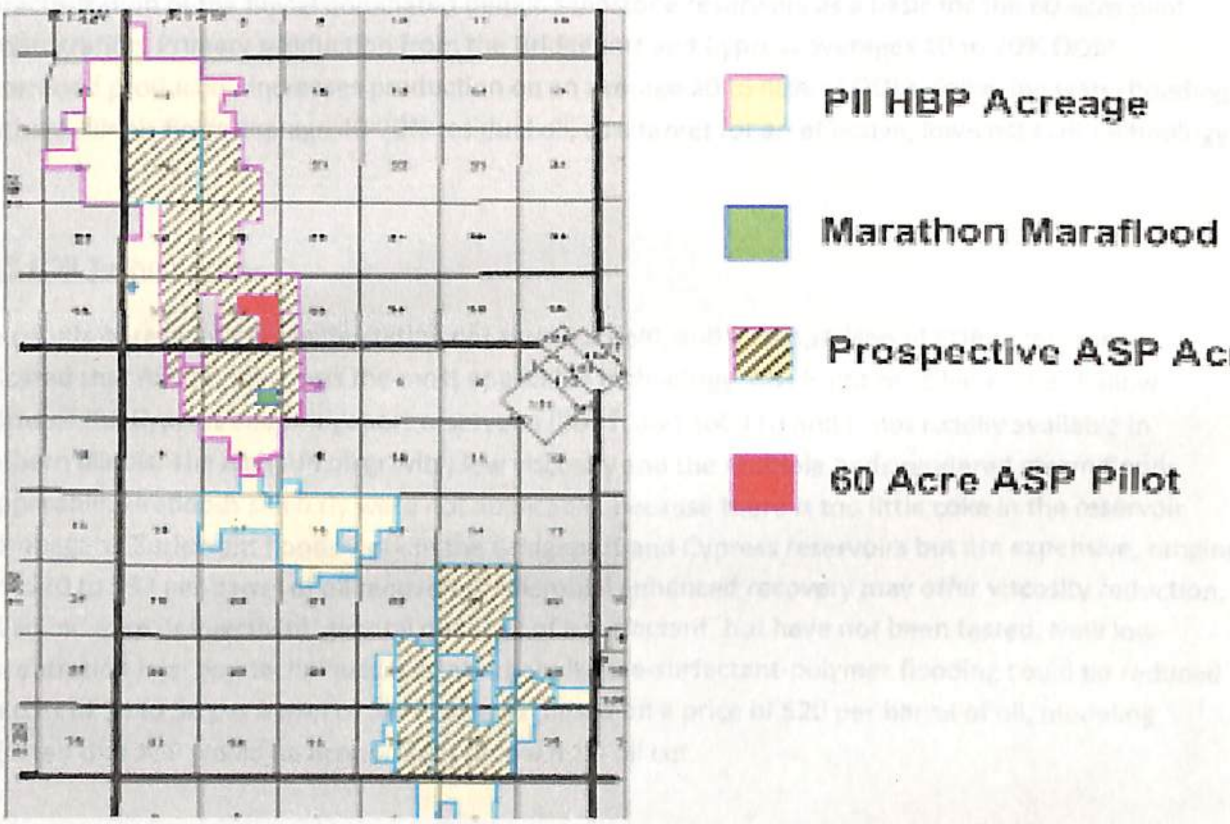


Figure 4.2- Lawrence Field showing the ASP pilot and Plains Illinois, Inc.'s holdings

4.7.1 Background-

Demonstration of surfactant flooding in southern Illinois in the late 1960s, 70s and 80s demonstrated that residual oil could be produced by chemical flooding, but the cost was sufficiently high and projects were rarely economic. The objectives of the DOE Class Revisit project were to perform a comparison of EOR techniques, determine lower cost flood patterns, use lower-cost alkaline- surfactant-polymer chemicals, recommend field expansion, and test the efficiencies of flooding multiple reservoirs simultaneously. The pilot at Lawrence field was attractive, because the reserves target for the 60-acre EOR pilot at Lawrence field was 42,000 MBO. The sandstones of the Pennsylvanian Bridgeport and Mississippian Cypress formations at Lawrence field were producing at less that a 3% oil cut, and were approaching their economic limit. The alkaline-surfactant-polymer flood utilizes reservoir characterization of the fluvial dominated deltaic sandstone reservoirs as a basic for the 60-acre pilot demonstration. Primary production from the Bridgeport and Cypress averages 10 to 20% OOIP. Waterflood production increases production on an average 20 to 40% of OOIP. Following waterflooding, southern Illinois fields average 40-70% residual oil, as a target for an effective, low-cost EOR technology.

4.7.2 EOR Technologies-

The results of reservoir characterization of Lawrence field, and a comparison of EOR techniques indicated that ASP flooding was the most applicable technology. CO_2 is not miscible at the shallow depths of the Cypress and Bridgeport reservoirs (900 ft and 1600 ft) and is not readily available in southern Illinois. The high API oil gravity, low viscosity and the multiple beds rendered steam floods inapplicable. Firefloods similarly were not applicable, because there is too little coke in the reservoir to propagate. Surfactant floods work in the Bridgeport and Cypress reservoirs but are expensive, ranging from $20 to $37 per barrel of oil recovered. Microbial enhanced recovery may offer viscosity reduction, and an increase or injectivity, general qualities of a surfactant, but have not been tested. New low-concentration injection techniques indicate that alkaline-surfactant-polymer flooding could be reduced to a cost of $4 to $8 per barrel of oil recovered. Based on a price of $20 per barrel of oil, modeling indicated that ASP would be economic at as low a 1% oil cut.

4.7.3 Lawrence Field-

Parameters, which made ASP flooding possible at Lawrence field, included an abundant access to fresh water for flooding, and shallow thick net pay intervals. Based on an original estimate of 1 billion barrels OOIP, and cumulative production of 330 million barrels of oil, Lawrence field has 400 to 700 BO remaining in- place. Two Mara flood surfactant flood projects (one in the Bridgeport and one in the Cypress) proved that surfactant flooding was successful, if not economically feasible. Previous surfactant floods were terminated due to the high cost of chemicals and/ or the low price of oil at the time. Because of the shallow production and available water, oil production at Lawrence field is economical at a very low oil cut, allowing a margin for investment in EOR technologies. During the reservoir characterization phase of the project, six wells were drilled and cored. The data was used to map porosity and permeability zones, defining five units in the Cypress sandstone and dividing the Bridgeport into A (3 units), B (3 units) and D (2 units). The Cypress sandstone, characterized by fine scale bedding features and thin units of rip-up clasts, which form permeability barriers, is interpreted as tidal deposition. The Cypress sandstone interval 4D, shown in Figure 4.3 , is the most porous and permeable unit in the Cypress. The Bridgeport A unit is a channel sandstone overlain by bedded coal. A basal channel lag in the Bridgeport A is cemented by pyrite. The Bridgeport B reservoir is characterized by sandstone intervals with herringbone and reverse laminated bedding features and intervals of high angle tabular cross-bedded sandstone. The reservoir in the Bridgeport B sandstone was identified as tidal channels encased in mixed mud flats. The third and uppermost reservoir unit in the Bridgeport, unit D represents cyclic deposition with shale and sandstone couplets of dark gray shale and sub parallel laminated sandstone indicating tidal deposition. The reservoir in the Bridgeport B sandstone was identified as tidal channels encased in mixed mud flats. Thin coal units are found through the Cypress and Bridgeport indicating low-lying swamps and mashes in the tidal delta. An area of seven sq. miles at Lawrence field has been identified by Plains Illinois for prospective ASP flooding.

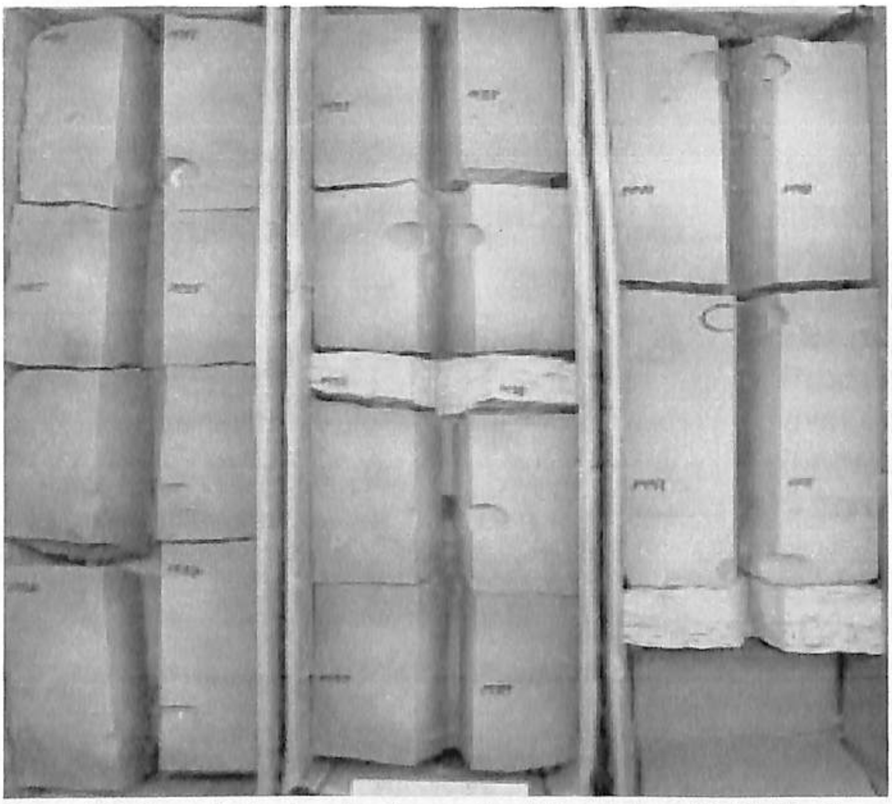


Figure 4.3- Core photo showing Cypress Sandstone interval 4(D). The Cypress Sandstone is the most porous and permable unit in Cypress. The core shows mottled iron staining. Rip-up clasts form permeablility barriers.

4.7.4 ASP Flood-

The goal of ASP flooding at Lawrence field was to duplicate the oil recovery performance of the old surfactant floods at a lower cost. Costs are lowered by optimizing the synergistic performance of the three chemicals used, and by injecting the chemicals at a low concentration. Chemicals used in the ASP flood are an alkali (NaOH or Na_2CO_3), a surfactant and a polymer. The alkali (1 to 2%) washes residual oil from the reservoir mainly by reducing interfacial tension between the oil and the water. The surfactant (0.1 to 0.4%) enhances the ability of the alkaline to lower interfacial tension. The polymer (800 to 1400 ppm) is added to improve sweep efficiency. The ASP chemical slug is injected first at approximately 30% pore volume. The polymer slug (approximately 25% pore volume) is injected next to push the ASP solution and maintains mobility control. Water is then injected to continue pushing the ASP and polymer slugs to the economic limit. Figure 4.4 shows the pattern of the ASP pilot at Lawrence field. Well spacing shows an injector pattern of 5 acres. Separate injection tests were performed on the Bridgeport and Cypress sands. The targeted ASP oil recovery for the project is 13.5% pore volume. The mini- mum net pay sand thickness targeted for each well was 40 ft.

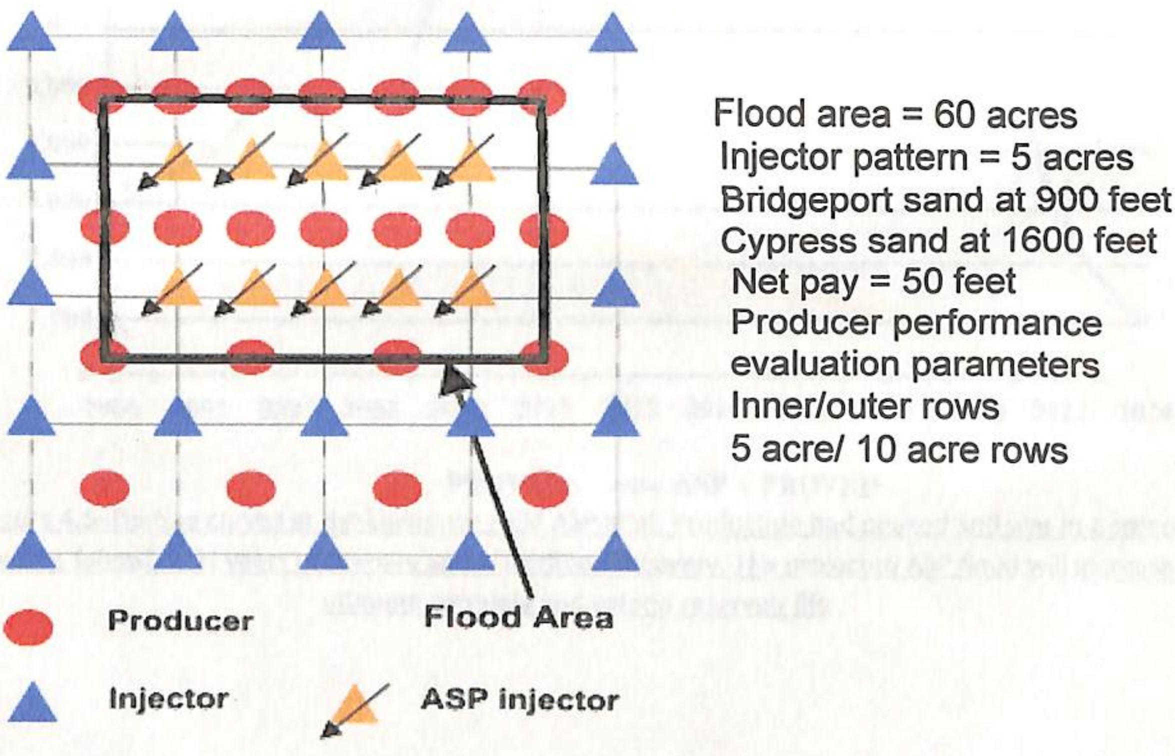


Figure 4.4- The Pilot ASP flood pattern indicating close spacing of ASP and water injectors and producing wells.

4.7.5 Summary-

The ASP flood pilot at Lawrence field utilizes three flood patterns with simultaneous ASP injection in the Bridgeport and Cypress sandstones. At the beginning of the project production from both reservoirs averaged less than 3% oil cut. Analysis and modeling of the reservoir characterization data and initial results indicate that oil recovery can be increased significantly. Figure 4.5 shows the decline curve predicted prior to the ASP flood, and curve and volume of oil projected to be recovered by the ASP flood. Based on the initial success of the ASP pilot Plains Illinois estimates that the full field project will be self-funding after 3 years. Reservoir life is anticipated to be extended for an additional 14 years. Future development plans by Plains Illinois include expanding the ASP floor to 320 acres in the seven mile prospect indicated in Figure 4.1.

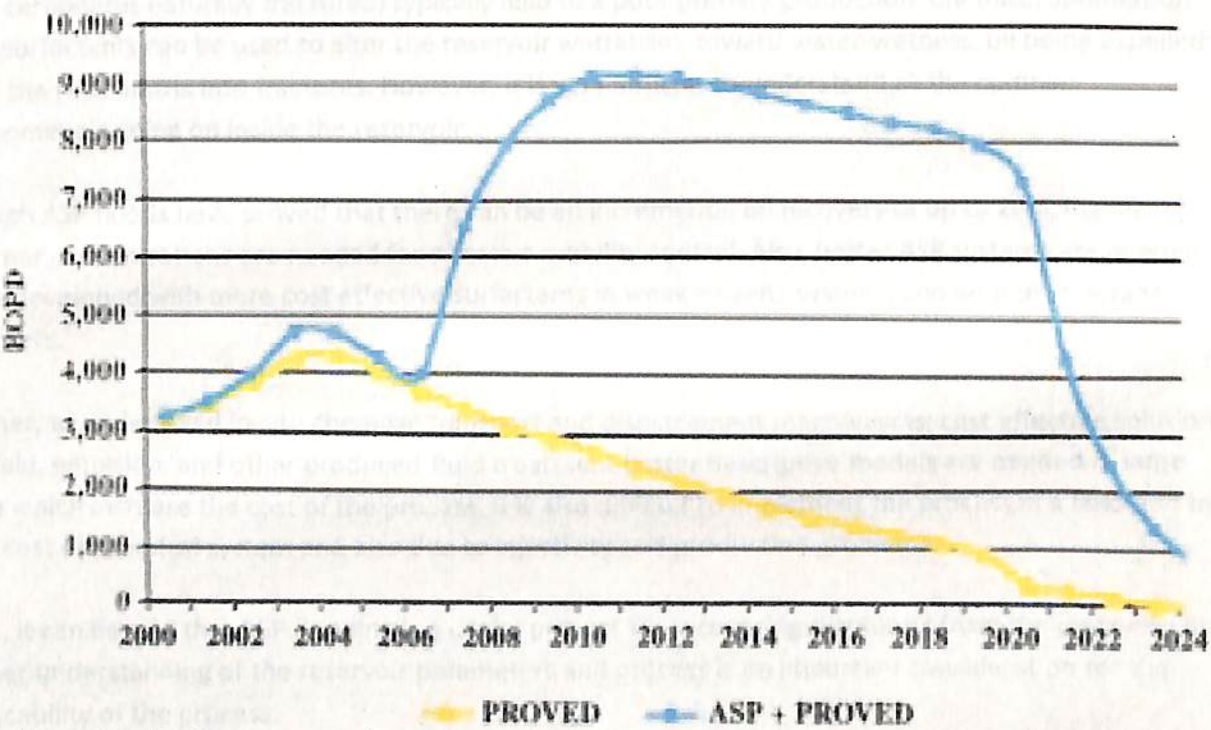


Figure 4.5- Decline curves at the Lawrence Field ASP pilot. Production had peaked and was in a steep decline following 96 years of primary and waterflood recovery. The projected ASP flood will increase ultimate recovery and extend reservoir life

Conclusion

Chemical flooding is an important technology for enhanced oil recovery. The production rates of the 100 largest oilfields in the world are all declining from plateau production. The challenge is to develop EOR methods that ensure an economical tail end production from these fields. Field practice has shown that polymer flooding can increase recovery by more than 12% OOIP, and that the production costs are comparable to that of water flooding. More than 20% OOIP incremental recoveries can be obtained with the ASP process. Better ASP systems need to be developed with more cost-effective surfactants in weak alkaline systems.

The higher quality reservoirs can utilize proven recovery technologies that could be applied with appropriate chemicals using processes economically profitable. The lower quality reservoirs (primarily tight carbonates naturally fractured) typically lead to a poor primary production. Chemical stimulation with surfactants can be used to alter the reservoir wettability toward water-wetness, oil being expelled from the rock matrix into fractures. However, it is very difficult to understand all the complex phenomena's going on inside the reservoir.

Though ASP floods have proved that there can be an incremental oil recovery of up to 20%, higher polymer concentrations are needed for effective mobility control. Also, better ASP systems are needed to be developed with more cost effective surfactants in weak alkaline systems and with pH-tolerant polymers.

Further, to understand in-situ chemical transport and displacement mechanisms; cost effective solutions to scale, emulsion, and other produced-fluid treatment better descriptive models are needed in large scale which increase the cost of the process. It is also difficult to implement the process in a field due to high cost of chemical system and also due to injectivity and production problems.

Thus, it can be said that ASP flooding is a useful process for recovering surplus oil from the reservoir. But proper understanding of the reservoir parameters and process is an important consideration for the applicability of the process.

Bibliography

1). Craft and Hawkins "Applied Petroleum Reservoir Engineering".

2). Donobue and Lang "A First Course in Petroleum Technology".

3). Surtek, Inc, "Coupling the Alkaline-Surfactant-Polymer Technology and The Gelation Technology to Maximize Oil Production".

4). Shunhua Liu, "Favourable Attributes of ASP Flooding"; SPE

5). Chang, H.L., "Polymer Flooding Technology Yesterday, Today, and Tomorrow," paper SPE 7043

6). Delamaide, E. *et al.*, "Daqing Oil Field: The Success of Two Pilots Initiates First Extension of Polymer Injection in a Giant Oil Field," paper SPE 27819.

7) Vincent Obiora Eme, "Design of an Alkaline/Surfactant/Polymer Enhanced Oil Recovery Scheme for a Saudi Arabian Limestone Reservoir".

8). G.J. Hirasaki and G.A. Pope "Analysis of factors influencing mobility and adsorption in the flow of polymer solution through porous media", SPE Journal.

9). A. Zaitoun and N. Kohler, "The role of adsorption in polymer propagation through reservoir rock", SPE 16274.

10). Ezeddin Shirif, "Mobility control by polymers under bottom -water conditions, Experimental Apprach", SPE 64506.

11).Websites-

http://www.chemtracers.com
http://www.spe.org
http://www.slb.com
http://surtek.com
http://sciencedirect.com
http://MKTechsolutions.com