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COMPARISON OF ECLIPSE AND
tNAVIGATOR

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Abstract

Objective of the study is to implement the commercially available software tools to the basic reservoir engineering problems in a real field case. Eclipse data set of Norne field, in the Norwegian sea, has been used for the study that is publicly available on https://opm-project.org/?page_id=559. Eclipse 100 and tNavigator have been used to run the simulations for verifying the feasibility of application of the ASP flooding for improving recovery.

Norne benchmark case is a real field black-oil model for an oil field in the Norwegian Sea. The model included dissolved gas, vaporized oil, transmissibility multipliers, pressure-dependent porosity and transmissibility, end-point scaling for relative permeability and capillary pressure. History-matching of production and pressures has already been done and well controls that change throughout the simulation schedule have also been included in the model.

Application of ASP flooding technique has been simulated in E100 and tNavigator as part of the study purpose. As matched in the history, water injection starts very early in the field. There are total 36 wells of which 9 are injection wells and the remaining 27 are production wells. Five wells are exclusively water injection wells and they have been used to inject ASP slugs along with the water.

In Eclipse E100, alkaline model is a simple model that does not take any chemical reactions into consideration, but when used in conjunction with surfactant and polymer to perform an Alkaline-Surfactant- Polymer (ASP) flooding, the alkaline can reduce the adsorption of both surfactant and polymer on the rock surface, therefore enhancing the effectiveness of the surfactant and polymer drive.

Eclipse and tNavigator work in the same format of E100 text pad code. Results from the both software are comparable. tNavigator has a very good graphical user interface to interact with the tool and all the graphs are defaulted and simultaneously can be viewed as the simulation time progress and it is faster than the Eclipse 100.

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1. Screening of EOR Methods

1.1 Introduction

Natural depletion of the oil generally recovers only up to 30% of the original oil in place including the artificial lift methods. Up to 50% of original oil can be recovered with the application of secondary recovery methods such as water flooding and pressure maintenance techniques. Tertiary recovery methods such as thermal, chemical, gas and microbial injection techniques may result in increased recovery of almost 80%. Water injection can be used along with the gas sandwitching water and gas alternatively- is another technique that combines both secondary and tertiary recovery methods and it is known as water alternating gas injection, in short WAG injection. Figure 1.1 shows the general classification of EOR techniques loosely.[1]
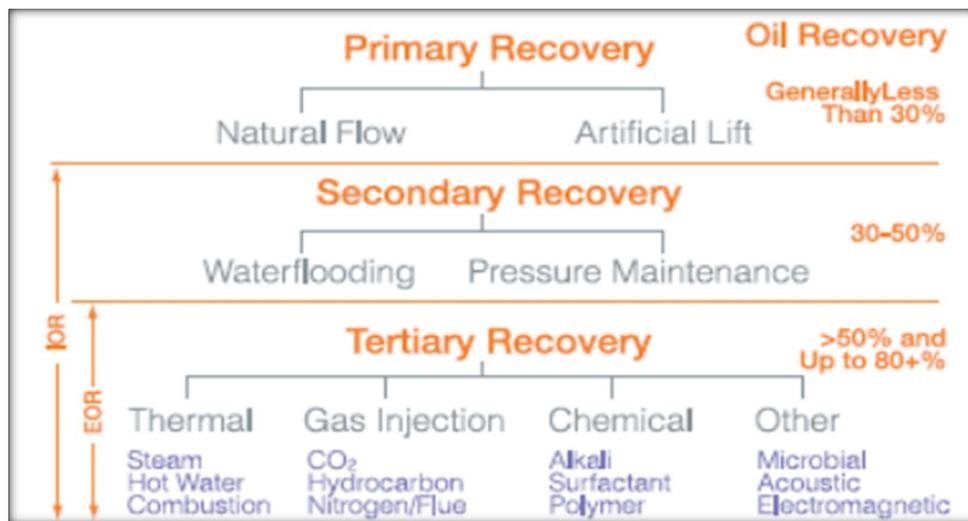
Figure 1.1: Oil Recovery Methods[1]

Though the terms tertiary and enhanced recovery are used interchangeably technical communications are improved if the terms stick to their intended technical meanings. There are successful enhanced recovery projects conducted as tertiary, secondary, and even as enhanced primary operations. The terms should continue to be used with their evolved historic meanings. For example, CO_2 flooding works quite well as either secondary or tertiary projects. Projects such as steam or polymer flooding are most effective as enhanced secondary operations. Experience shows that the best profits come only from those methods where several barrels of fluid

(liquid or gas at reservoir pressure) can be injected per barrel of incremental oil produced.

Application of a specific recovery method depends on various geological, PVT, environmental and economical parameters. The reservoir and injection conditions should be chosen to optimize the displacing mechanisms wherever possible; example, using high enough pressure to achieve miscibility in solvent flooding and looking for shallow reservoirs to reduce wellbore heat losses in steam flooding.

Screening of the applicable EOR methods specific to the project requires understanding of 'which method suits better for an application'; hence it is important to understand the drive mechanisms involved in various methods. Broadly there are three kinds of mechanisms at work for displacing additional oil with an injected fluid:

(1) solvent extraction to achieve (or to approach) miscibility
(2) interfacial-tension (IFT) reduction
(3) viscosity change of either the oil or water,
and/or an additional pressure added due to the fluid injection.

There is overlap of the mechanisms. For example, IFT is lowered as miscibility is approached in the "solvent" methods.

A very generic Industry classification of current EOR methods has been shown in Table 1.1.

```
Solvent extraction and/or "miscible-type" processes
    Nitrogen and flue gas
    Hydrocarbon-miscible methods
    CO₂ flooding
    "Solvent" extraction of mined, oil-bearing ore
IFT reduction processes
    Micellar/polymer flooding (sometimes included in miscible-
        type flooding above)
    ASP flooding
Viscosity reduction (of oil) or viscosity increase (of driving fluid)
    processes plus pressure
    Steamflooding
    Fireflooding
    Polymer flooding
    Enhanced gravity drainage by gas or steam injection
*Classified by the main mechanism of oil displacement (excluding gel treatments).
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Table 1.1: General Classification of EOR Methods[2]

1.2 EOR Methods based on Mechanism at Work

1.2.1 Gas Injection Methods

Effectiveness of the gas injection methods depends on the miscibility of the injection fluid/gas with the reservoir fluid. Independent of the gas being injected, a concept of MMP, minimum miscibility pressure is important for all the gas injection methods. MMP is the minimum pressure at which the injection gas phase is completely miscible into the hydrocarbon phase of the reservoir. As mentioned in Table 1.1, injection can be either Nitrogen and Flue gas, hydrocarbon gas or CO_2. History shows that with a properly designed miscible injection a recovery of up to 90% can be achieved.

Nitrogen and Flue-Gas Injection

Nitrogen and flue gas are the cheapest gases and have the similar MMPs for good displacement and hence considered together and can be used interchangeably for oil recovery. The downside of the flue gas is the corrosion and hence Nitrogen is more preferred. Unfortunately, it has the highest MMP, so miscible displacement is possible only in deep reservoirs with light oils.

For hydrocarbon injection, the injection method can be subdivided into first-contact-miscible (LPG solvent), condensing (or enriched) gas drive and the vaporizing (or

3

high-pressure) gas drive. In terms of the pressure required for efficient miscible displacement, hydrocarbon gases are in between the very high pressures required for nitrogen and the more modest range of pressures for CO_2.

The density and therefore the solubility of CO_2 in oil decreases with temperature, so the MMP required for a given oil will increase with higher temperatures. Since the reservoir temperature normally increases with depth, the MMP must also increase with depth; but fortunately, the pressure required to fracture reservoirs increases much faster than temperature with depth[2].

1.2.2 IFT Reduction Methods

The goal of the chemical methods is to reduce the IFT between oil and water, generally to displace discontinuous trapped oil (remaining oil saturation, S_{or}) that remains after a waterflood.

Polymer flood is mobility control process that alters the viscosity of the water flood and hence improves the sweep efficiency. Designing of polymers should consider the permeability constraints for polymer flooding. For a given polymer, chemical retention increases and the rate of polymer propagation decreases with decreasing rock permeability. High-molecular-weight polymers often experience high retention and low propagation rates for rock permeabilities of less than 100 md. This permeability constraint can be relaxed by using polymers with lower molecular weights. However, the viscosity provided by a polymer decreases with decreasing molecular weight, so more polymer (and a higher cost per viscosity unit) is needed as the rock permeability and the maximum allowable polymer molecular weight decrease.

HPAM (hydrolyzed polyacrylamide and xanthan polymers) do not have the history of successful implementation for reservoir temperatures above 175 F. More stable polymers (e.g., Scleroglucan and acrylamide copolymers and terpolymers) are available for high-temperature use, but are expensive. Water salinity is another important issue in polymer flooding. In the range from 0 to 1% TDS, the viscosities of HPAM solutions decrease substantially with increased salinity. Thus, high-salinity HPAM solutions are relatively ineffective during polymer flooding.

1.2.3 Thermal Methods

Thermal methods account for the biggest share of the world's enhanced oil production. In general, thermal methods have been used for those heavy-oil reservoirs that cannot be produced in any other way because the oil is too viscous to flow without the application of heat and pressure. Therefore, the successful projects are almost always enhanced secondary (or even enhanced primary because primary production was essentially nil in many fields).

Figure 1.2 shows the preliminary screening of EOR projects based on API gravity. Each EOR method is shown below the respective API gravity for which it is most suitable to; and the size of the block is an indication of relative production in comparison.
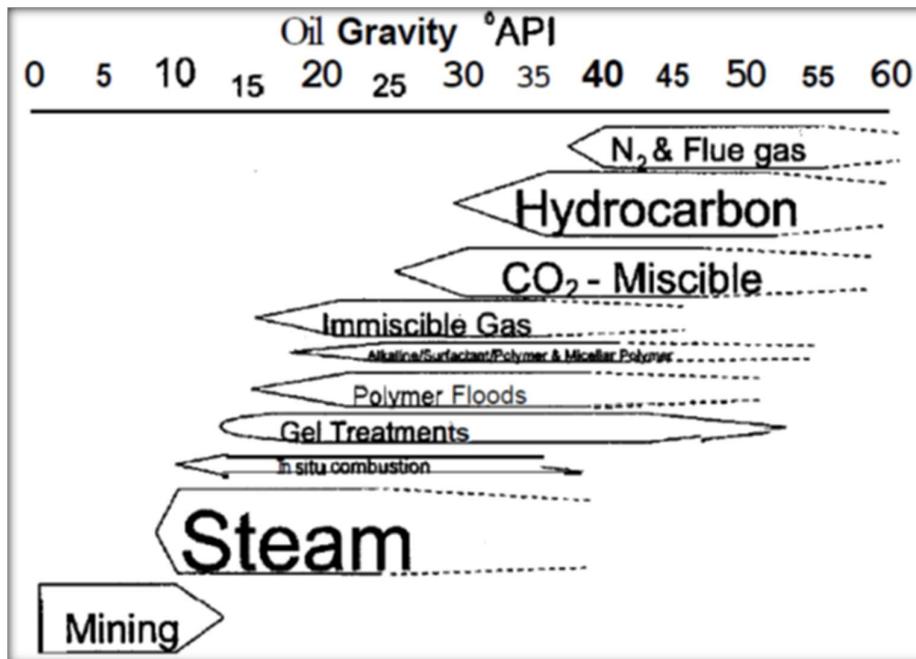
Figure 1.2: Preliminary Screening based on API[2]

1.3 Summary of Screening Criterion

EORs can be classified further down to the specific method of application based on reservoir characteristics and fluid properties. Based on the existing technology and industry experience of application of EOR projects, a summary of screening criterion for EOR projects has been tabulated (Ref 2) in Table 1.2.

Detail Table in Ref. 16	EOR Method	Oil Properties			Reservoir Characteristics					
		Gravity (°API)	Viscosity (cp)	Composition	Oil Saturation (% PV)	Formation Type	Net Thickness (ft)	Average Permeability (md)	Depth (ft)	Temperature (°F)
					Gas Injection Methods (Miscible)					
1	Nitrogen and flue gas	>35,↗48,↗	<0.4↘0.2↘	High percent of C_1 to C_7	>40↗75↗	Sandstone or carbonate	Thin unless dipping	NC	>6,000	NC
2	Hydrocarbon	>23,↗41↗	<3↘0.5↘	High percent of C_2 to C_7	>30↗80↗	Sandstone or carbonate	Thin unless dipping	NC	>4,000	NC
3	CO_2	>22↗36↗ ᵃ	<10↘1.5↘	High percent of C_5 to C_{12}	>20↗55↗	Sandstone or carbonate	Wide range	NC	>2,500ᵃ	NC
1–3	Immiscible gases	>12	<600	NC	>35↗70↗	NC	NC if dipping and/or good vertical permeability	NC	>1,800	NC
					(Enhanced) Waterflooding					
4	Micellar/ Polymer, ASP, and Alkaline Flooding	>20↗35↗	<35↘13↗	Light, intermediate, some organic acids for alkaline floods	>35↗53↗	Sandstone preferred	NC	>10↗450↗	>9,000↘3,250	>200↘80
5	Polymer Flooding	>15	<150, >10	NC	>50↗80↗	Sandstone preferred	NC	>10↗800↗ ᵇ	<9,000	>200↘140
					Thermal/Mechanical					
6	Combustion	>10↗16→?	<5,000 ↓ 1,200	Some asphaltic components	>50↗72↗	High-porosity sand/ sandstone	>10	>50 ᶜ	<11,500↘3,500	>100↗135
7	Steam	>8 to 13.5→?	<200,000 ↓ 4,700	NC	>40↗66↗	High-porosity sand/ sandstone	>20	>200↗2,540↗ ᵈ	<4,500↘1,500	NC
—	Surface mining	7 to 11	Zero cold flow	NC	>8 wt% sand	Mineable tar sand	>10ᵉ	NC	>3:1 overburden to sand ratio	NC

NC=not critical.
Underlined values represent the approximate mean or average for current field projects.
ᵃ See Table 3 of Ref. 16.
ᵇ > 3md from some carbonate reservoirs if the intent is to sweep only the fracture system.
ᶜ Transmissibility > 20 md-ft/cp
ᵈ Transmissibility >50 md-ft/cp
ᵉ See depth.

Table 1.2: Summary of Screening Criteria for EOR Methods[2]

2. ASP Flooding

2.1 ASP Flooding

Many oil fields across the world have been under waterflooding, implementation of chemical EOR methods is easier and it is possible fewer additional facilities. Among the chemical methods, alkaline–surfactant–polymer (ASP) is the most promising method because of the synergy between alkaline, surfactant, and polymer. In an ASP process, alkali, surfactant, and polymer are added in the same solution slug. However, if the produced water with oil and suspensions is used (in ASP slug), or the water has high total dissolved solids (TDS) and high divalent cations, it will warrant very complex and expensive facilities.

Mechanisms

2.1.1 Polymer Flooding

Polymer flooding is same as waterflooding except that polymer is added in the water so that the solution viscosity is increased. Sometimes, it is called thickened waterflooding. Equation 2.1 shows the fractional flow of water in a water flooded reservoir.

$$f_w = \frac{1}{1+\left(\frac{k_{ro}}{k_{rw}}\right).\frac{\mu_w}{\mu_o}} = \frac{1}{1+\frac{\lambda_o}{\lambda_w}} \qquad (2.1)$$

where,
K_{ro} and k_{rw}= the relative permeabilities of oil and water phases
μ_o and μ_w = the viscosities of oil and water phases.
λ_o and λ_w= the mobility ratios defined as follows

When a polymer is added water viscosity μ_w is increased and the water cut will be decreased. As a result, more oil can be recovered at the same amount of water injected compared with waterflooding. When polymer is injected in vertically heterogeneous layers, crossflow between layers improves polymer allocation in the vertical layers so that the vertical sweep efficiency is improved.

Because of polymer adsorption, the permeability in polymers flowing path is reduced and thus reducing the water flow velocity. This is called permeability reduction effect. After polymer flooding, the permeability of the subsequent water still

remains low since the polymer adsorption is an irreversible process so that the adsorbed polymer cannot be simply flushed away. This is called residual permeability effect. Through the use of this mechanism, polymer can reduce water relative permeability k_{rw} much more than oil permeability k_{ro}. The increased water viscosity and reduced water relative permeability result in reduced water mobility λ_w. Thus, the mobility ratio of water to oil (λ_o) is reduced and more oil will be recovered.

Some small pores cannot be accessed by large polymer molecules. This phenomenon is called inaccessible pore volume (IPV). IPV makes polymer molecules transport faster than its solvent (solution). But the velocity is retarded by adsorption. The resultant transport velocity is the balance between the two. Polymer adsorption may be described by the Langmuir-type isotherm. It increases with salinity but decreases with permeability. As the polymer molecular weight (MW) becomes higher, the solution viscosity is higher compared with a lower-MW solution at the same concentration. Therefore, in high permeability reservoirs, high-MW polymer is preferred.

Polymer solution viscosity will decrease with the salinity of water and biopolymers are an alternative as they are more tolerant to salinity but more sensitive to temperature. Economically, polymer flooding may be advantageous since it reduces the amount of water injected and produced, compared to the normal waterflooding; polymer improves the sweep efficiency, less water is produced and injected.

2.1.2 Surfactant Flooding

The key mechanism for surfactant flooding is lowering interfacial-tension (IFT) between oil and gas phases. To understand the mechanism it is important to understand the concept of capillary number versus residual oil saturation. The capillary number, N_c, is defined as shown in Equation 2.2[3].

$$N_c = \frac{u \cdot \mu}{\sigma \cdot (cos\theta)} \qquad (2.2)$$

where,
μ = viscosity of the displacing fluid
u = the displacing Darcy velocity

θ = the contact angle

and σ = the IFT between the displacing fluid and the displaced fluid (oil)

Experimental data shows that as the capillary number is increased, the residual oil saturation is decreased, as summarized by Stegemeier[4]. Capillary number defined in Equation 2.2 is a semi-empirical and different forms have been used in the literature. In particular, $cos\theta$ is omitted in some forms for simplicity. However, the contact angle can be an essential parameter when the mechanism of adding surfactants is to change wettability, such as using surfactants in oil-wet carbonate reservoirs.

A typical capillary number for waterflooding is about 10^{-7}. To reduce the residual oil saturation in water flooding, the capillary number must be significantly higher 10^{-7}, typically in the order of 10^{-4}. It can be done in three ways:

(1) increasing injection fluid velocity u,
(2) increasing displacing fluid viscosity μ and
(3) reducing the IFT σ.

The injection fluid velocity is limited by pump capacity or formation injectivity. Even though the pump capacity is not a problem, if the injection velocity is too high, the injection pressure may be higher than the formation fracture pressure. Increasing injection fluid viscosity is limited at least by economics, because increasing polymer solution viscosity needs a higher polymer concentration.

It is known that the IFT between a surfactant solution and oil can be reduced from 20–30 to 10^{-3}mN/m. It means, by adding surfactants, the capillary number can be practically increased by more than 1000 times. Because of the lowest IFT, oil droplets can flow more easily through pore throats because of reduced capillary pressure. The oil droplets move forward and merge with the oil down the stream to form oil bank. In some circumstances, wettability alteration and emulsion flooding could also be important.

2.1.3 Alkaline Flooding

Utility of the alkaline in reservoir flooding is to generate an in-situ surf component that will in turn reduces the IFT between the oil and water. Typical chemical equation for in-situ surf generation is shown in equation 2.3.

$$HA + OH^- \rightarrow A^- + H_2O \qquad\qquad (2.3)$$
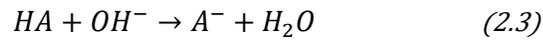
where,

HA is a pseudo-acid component

and A$^-$ is the soap component.

Apart from the generation of in-situ surf, the main advantage of using alkali is the reduction of adsorption of surf by the reservoir rock and promotes the efficiency of the surf.

2.1.4 Synergy

An incomplete list of the interactions of ASP has been summarized below:

- Alkaline injection reduces the adsorption of surfactant and polymer.
- Alkali reacts with crude oil to generate soap. Soap has low optimum salinity, whereas a synthetic surfactant has relatively high optimum salinity. The mixture of soap and the synthetic surfactant has a wider range of salinity in which the IFT is low.
- Emulsions improve the sweep efficiency. Soap and surfactant make emulsions stable owing to the reduced IFT. Polymer may help to stabilize emulsions owing to its high viscosity to retard coalescence.
- There is a competition of adsorption sites between polymer and surfactant. Therefore, adding polymer reduces surfactant adsorption, or vice versa.
- Adding polymer improves the sweep efficiency.

2.2 Parameters affecting ASP flooding

The most critical parameters are reservoir temperature, formation water salinity, and divalent contents, clay contents, oil viscosity, and formation permeability. Table 2.1 is the summary of critical parameters from various ASP flooding projects.

Proposed by	μ_o (cP)	S_o (frac.)	k (mD)	T_r (°C)	Formation water salinity, (TDS, ppm)	Divalent (ppm)	Lithology	Clay	Well Spacing (ft)	Aquifer	Gas cap	DP-coefficient	API gravity	Depth, ft
Lake et al.[21]	<200													
Taber et al.[22,23]	<35	>0.35	>10	<93.3	<20000	<500		Low					>20	<9000
Al-Bahar et al.[24]	<150		>50	<70	50000	1000	Sandstone	Low		No	No			
Dickson et al.[20]	<35	>0.45	>100	<93.3	<200000 if T_R < 60 °C, <50000 if T_R > 60 °C									500–9000
From ASP projects	12.9	0.3	473.0	52	7993	178	Sandstone	Low	403.6	Weak in few cases	No	0.56	26.6	3238
Proposed in this paper	<50	>0.3	>50	<95	<50000	<100	Sandstone	Low	<656	Weak	Weak	NC	>20	NC

In the table, μ_o is oil viscosity, S_o is oil saturation before ASP, T_r is reservoir temperature, NC means not critical for oil recovery. ASP, alkaline–surfactant–polymer API; American Petroleum Institute; DP, Dykstra and Parsons.

Table 2.1: Screening Criteria for Selection of ASP Flooding[3]

2.2.1 Formation

Anionic surfactants have high adsorption in carbonates and cationic surfactants are expensive and hence most of the stimulation projects were reported in sandstone reservoirs. Another reason is that in alkaline consumption and precipitation of anhydrites is high in carbonate reservoirs. Clays in sandstones also cause high surfactant adsorption and high alkaline consumption Therefore, clay contents must be low for a chemical EOR application.

2.2.2 Oil Composition and Oil Viscosity

Oil composition is very important to alkalis and surfactants, but it is not critical to polymer. Oil viscosities less than 35 cP are favorable for an alkaline–surfactant (AS) project.

2.2.3 Formation Water Salinity and Divalents

Most of ASP projects were carried out in low-salinity reservoirs of about 10,000 ppm. Al-Bahar et al[4] criterion is 50,000 ppm salinity and 1,000 ppm hardness. Though the formation water salinity and divalents are important to ASP EOR, the salinity and divalent content in the water used to dissolving chemicals are much more important. This is because the salinity and divalents in the formation water can only affect the

chemical slug performance through mixing with the chemical slug, but the salinity and divalents in the chemical slug will directly affect the chemical slug performance.

2.2.4 Reservoir Temperature

According to Taber et al[5], the reservoir temperature should be lower than 93 ºC for A/S/P projects, but the average temperature for actual A/S field projects was 27 ºC, and the average temperature for polymer projects was 60 ºC.

2.2.5 Formation Permeability

High permeability is favorable to ASP flooding, and it is critical to polymer injection. Simply, polymer may not be able to flow through low permeability formations.

2.3 Laboratory Work

So far, all the attempts to establish a good screening criterion is completely based on the available data from the projects that successfully applied various EOR methods. Among the parameters discussed, reservoir temperature and water salinity are the most critical parameters. However, as chemical products are improved, the screening criteria will be changed. From the current chemical EOR technology, extensive laboratory measurements are still needed for every project. Simulation work is needed to analyze laboratory data and upscale to a field model for potential prediction. ASP EOR in high temperature and high salinity is a challenge.

There are so many laboratory tests, but there are few important and mandatory tests for going into an ASP project. Polymers require the aqueous stability test, filtration test, and viscosity measurements at different shear rates.

To select surfactants, in additional to the aqueous stability test, one necessary test is the phase behavior test also called salinity scan test. For the salinity scan test, a fixed water–oil volume ratio that is generally one is stabilized in pipettes to check the emulsion stability. Generally three of microemulsions are formed depending on salinity:

type I—oil-in-water microemulsion,

type II— water-in-oil microemulsion,

type III—bi-continuous middle-phase microemulsion.

One important objective from such test is to select a surfactant or surfactants that can have high solubilization ratios of oil to surfactant volumes and water to surfactant volumes, which will be achieved if the middle-phase volume in Figure 1.3 is high when the optimal salinity of the surfactants have been chosen. The optimal salinity corresponds to the maximum middle-phase volume in Figure 2.1.
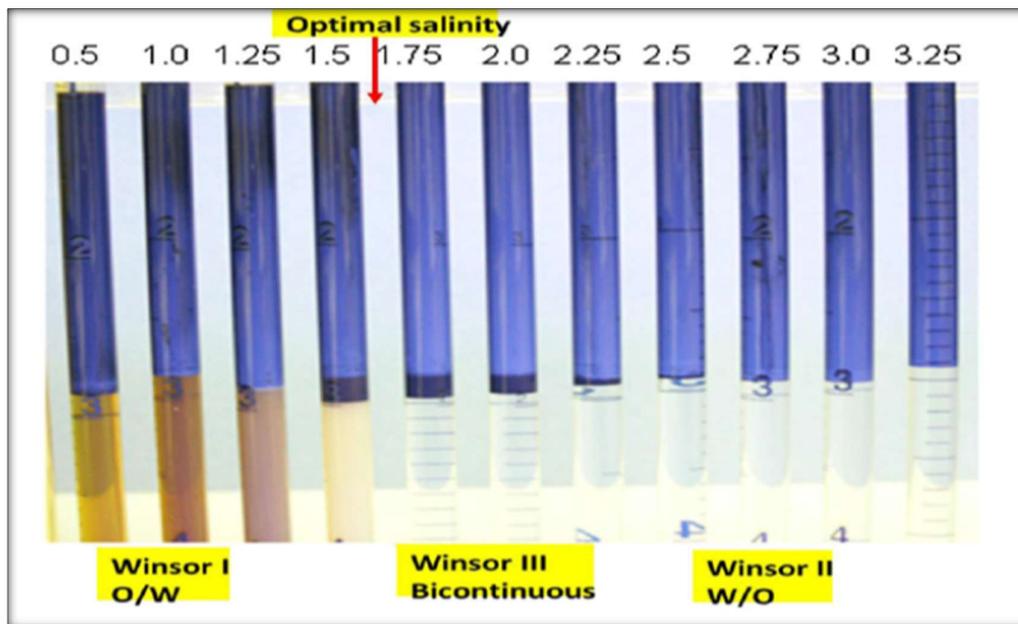

Figure 2.1: Photograph of Typical Salinity Scan Test for Phase Behavior

The top numbers are salinity in weight percent. Different types of microemulsions are shown as the salinity is inceased[1].

According to Huh's[6] equations, high solubilization ratios will generate very low IFT, preferably in the order of 10^{-3}mN/m. Selection of surfactants based on the solubilization ratios may be an alternative to the IFT measurement as Huh's[6] equations may be used to calculate IFT from the solubilization ratios.

An additional test called oil scan also needs to be run. In this test, the water–oil volume ratio is changed, because alkali reacts with the acid component in the crude oil and different saturations of oil in the reservoir in different phases of the project will result in different amount of soap generated in situ; thus the phase behavior of the mixed soap and injected surfactant will change with the water–oil ratio (or oil saturation).

Because only very limited experiments can be affordable, a database built from the existing projects and the literature will be very useful. Many laboratories measured data such as the salinity scan data, polymer viscosity data, and polymer and surfactant adsorption data are input in a simulation model to history-match core flood tests. By history matching core flood tests, the flow parameters and chemical parameters are calibrated, and these parameters are then used in field-scale models to predict field oil recovery performance.

2.4 Field Experience

Before carrying out a field pilot, generally, a single well (chemical) tracer test (SWTT) is conducted. The SWTT is sometimes called chemical huff and puff. During an SWTT, a slug of ASP solution is injected in a well, and the oil saturation before and after the chemical injection is measured. The main objective is to see how much oil saturation can be reduced. Such test is less expensive, but there is an uncertainty in estimating oil saturation and no information regarding inter-well connectivity, sweep efficiency, and injectivity can be obtained. When a field pilot is conducted, more expensive observation wells may be drilled.

Most of the field ASP projects were conducted in either five-spot patterns or inverted five-spot patterns. The Lagomar pilot was in an inverted seven-spot pattern, the Jilin Hong-Gang pilot was in an inverted 13-spot pattern, and the Sa-bei was in a four-spot pattern.

As per the reported statistics so far China has successfully implemented 12 ASP projects and Daqing fields have 144 injectors. Among these seven projects, four projects have more than 100 injectors. The average well spacing is 484 ft, the surfactant used in these large-scale projects is heavy alkylbenzene sulfonate. The IFT achieved was 10^{-3} to 10^{-4}mN/m, when 0.05–0.3wt% surfactant is mixed with 0.4–1.2wt% alkali. The surfactant adsorption is less than 1mg/g sand. The field performance showed significant increase in oil rate increase and reduction in water cut. Downsides are the problems associated with scaling and corrosion, which damaged the lifting system and shortened pump working life; and strong emulsification, which made liquid treatment difficult.

2.5 Injection Scheme and Injection Rates

A typical ASP injection process has three slugs: pre-slug, main ASP slug, and post-slug. The function of a pre-slug is to inject polymer solution for profile improvement. Sometimes, alkaline slug is injected as a pre-slug. Its objective is to remove high-concentration divalents to avoid association of these divalent with the subsequent surfactants. Sometimes, the injected alkalis can react with divalents so that insoluble precipitates are generated. The precipitates reduce permeability; thus sweep efficiency of the polymer and surfactant is improved. This process is known as mobility-controlled caustic flood. The average injected pre-slug pore volumes (PV) are 9.7% PV, and the average polymer (P) concentration was 0.145 wt%. The main slug consists of alkali (A), surfactant (S), and polymer (P). The average injection concentrations of these chemicals were 1.25 wt% A, 0.27 wt% S, and 0.135 wt% P, respectively, and 30.8% PV was injected. After the main slug is injected, if only water is injected, the water will finger into the main ASP slug, because water mobility is much higher than that of ASP slug. To avoid the fingering, a post-slug of polymer is injected immediately following the main ASP slug. In some cases, a graded or tapered scheme that is an empirical model is used to reduce the amount of polymer injected. The simplest model assumes that the polymer concentration declines exponentially. Claridge[7] and Stoneberger and Claridge[8] developed a method based on the method by Koval[9] to design graded viscosity banks. However, as the amount of polymer injected becomes larger, water would have less opportunity to break through the polymer slug ahead of it if the polymer slug is large. The average injected post-slug was 24.2% PV and the average polymer concentration was 0.08 wt%. In general, incremental oil recovery over waterflooding would increase with the amount of chemicals injected.

When designing a chemical injection scheme, formation injectivity needs to be considered. If the chemical slug is too viscous, the injection pressure builds up and the formation could be fractured. If the fractures extend from an injector to a producer, the chemical slug could quickly breakthrough.

3. Technical Description of Simulation

3.1 Surfactant Model

The distribution of injected surfactant is modeled by solving a conservation equation for surfactant within the water phase. The surfactant concentrations are updated fully-implicitly at the end of each time-step after the oil, water and gas flows have been computed. The surfactant is assumed to exist only in the water phase, and the input to the reservoir is specified as a concentration at a water injector.

3.1.1 Calculation of Capillary Number

The capillary number is a dimensionless group that measures the ratio of viscous forces to capillary forces. The capillary number is given by

$$N_c = \frac{|K*grad\,P|}{ST} * C_{unit} \qquad (3.1)$$

where,

K= the permeability,

P= the potential,

ST= the interfacial tension and

C_{unit}= the conversion factor depending on the units used.

$|K \cdot grad\,P|$ is calculated by

$$|K \cdot grad\,P| = \sqrt{(K_x \cdot grad\,P_x)^2 + \left(K_y \cdot grad\,P_y\right)^2 + (K_z \cdot grad\,P_z)^2} \qquad (3.2)$$

3.1.2 Relative Permeability Model

The Relative Permeability model is essentially a transition from immiscible relative permeability curves at low capillary number to miscible relative permeability curves at high capillary numbers. A table that describes the transition as a function of $\log_{10}$(capillary number) is provided to Eclipse.

The relative permeability used at a value of the miscibility function between the two extremes is calculated in two steps. Firstly the end points of the curve are interpolated and both the immiscible and the miscible curves are scaled to honor

these points. The relative permeability values are looked up on both curves, and the final relative permeability is taken as an interpolation between these two values. Figure 3.1 shows the actual relative permeabilities of oil and water in original condition and the rock relative permeabilities when the water is 100% miscible with the surfactant.
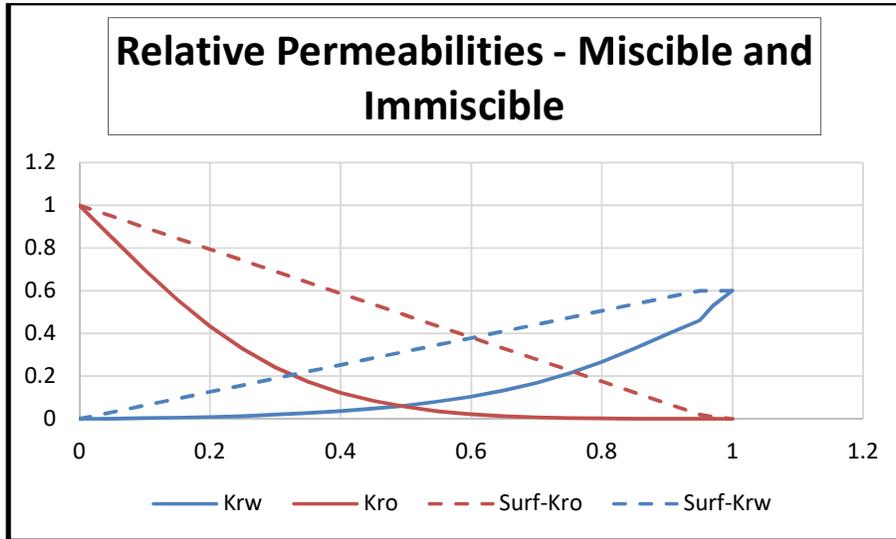

Figure 3.1: Relative permeabilities- Miscible and Immiscible

3.1.3 Capillary Pressure

The water oil capillary pressure will reduce as the concentration of surfactant increases; and it is that reduction in oil water capillary pressure that in turn reduces the residual oil saturation. This will eventually result in increased recovery.

The new oil water capillary pressure is calculated as in Equation 3.3.

$$P_{cow} = P_{cow}(S_w) \frac{ST(C_{surf})}{ST(C_{surf} = 0)} \qquad (3.3)$$

where,

ST(C_{surf}) is the surface tension at the present surfactant concentration,

ST(C_{surf}=0) is the surface tension at zero concentration,

$P_{cow}(S_w)$ is the capillary pressure from the immiscible curves initially scaled to the interpolated end-points calculated in the relative permeability model.

3.1.4 Water PVT Properties

Surfactant modifies the viscosity of the pure water and hence will be modified depending on the concentration of surfactant. Viscosity of the surfactant is given as an input to the simulator.

Equation 3.4 will be used to calculate the insitu water-surfactant viscosities.

$$\mu_{ws}(C_{surf}, P) = \mu_w(P) \frac{\mu_s(C_{surf})}{\mu_w(P_{ref})}$$ *(3.4)*

where

μ_s is the viscosity of surfactant,

μ_w is the viscosity of water,

μ_{ws} is the viscosity of the water-surfactant mixture,

P and P_{ref} *are* gridblock and reference pressures,

C_{surf} and C_{sref} are insitu and reference concentrations.

3.1.5 Treatment of Adsorption

Adsorption of surfactant is assumed to be instantaneous, and the quantity adsorbed is a function of the surrounding surfactant concentration. The user is required to supply an adsorption isotherm as a function of surfactant.

3.1.6 Modeling the Change of Wettability

Figure 2.1 shows the interpolation of water wet and oil wet end points to be assumed to be ideal for 100 % of surfactant. Anything in between during the process of calculations is taken as the weighted average of the two curves depending on the in-situ surf concentration.

Equation 3.5 shows the formula for calculating the wet phase oil permeabilities.

$$k_r = F \cdot k_r{}^{ow} + (1 - F) \cdot k_r{}^{ww}$$ (3.5)

F is the weightage factor depending on the surf concentration,

K_{row} is the scaled oil-wet k_r,

K_{rww} is the scaled water-wet k_r

This defines new immiscible saturation functions that are then used in the Relative permeability and Capillary pressure models.

3.2 Polymer Flood Model

The main objective of polymer injection during water flooding of oil reservoirs is to decrease the mobility of the injected water. This decrease results in a more favorable fractional flow curve for the injected water, leading to a more efficient sweep pattern and reduced viscous fingering. Certain plugging effects within highly permeable layers may also occur and result in the diversion of the injected water into less permeable zones of the reservoir.

The mobility decrease of the injected water resulting from the addition of polymer is due to two effects. Firstly, the viscosity of the polymer solution is higher than that of pure water (the viscosity of the polymer solution increases as the concentration of the polymer in the water increases). Secondly, the rock permeability to water is reduced after the passage of a polymer solution through the rock material (the permeability to oil is, however, largely unaffected). Both effects combine to reduce the value of the water mobility while that for the oil is unaltered.

To achieve maximum efficiency, the polymer solution is often applied in the form of a tapered slug. At the front edge of the slug, the displacement is stable but the interface between the water and the polymer solution smears due to physical dispersion of the polymer. At the rear edge, the mobility ratio is unfavorable and is dominated by viscous fingering. Both effects cause deterioration of the slug and are modeled in ECLIPSE by means of a mixing parameter applied to the viscosity terms in the fluid flow equations.

A further effect caused by the adsorption and entrapment processes is a reduction in the relative permeability of the polymer solution. The reduction results from an interaction between the aqueous solution and the polymer retained by the rock material. For modeling purposes it will be assumed that the reduction in permeability to the polymer solution is proportional to the quantity of polymer lost to the rock material. The permeability of the rock to water is thus permanently reduced after the passage of a polymer slug compared to its value before the

passage. Experimentally, it is found that only a very small change occurs to the hydrocarbon relative permeability and the ECLIPSE model assumes that the change is negligible.

In core flooding experiments, it is often observed that injected polymer slugs break through to producers earlier than tracer slugs (for example, NaCl). The polymer fluid velocity is higher than that of the tracer fluid within the porous medium and this is due to the fact that only a fraction of the total pore space is available to the polymer fluid. As the inaccessible pore space to the polymer fluid increases, the effective polymer velocity through the rock increases and leads to a faster breakthrough of polymer.

The rheology of polymer solutions is not simple. At low flow rates the viscosity of the solution is approximately constant and depends only on the concentration of polymer in the solution. At higher flow rates the solution viscosity reduces in a reversible (elastic) manner. At even higher velocities the large polymer molecules begin to break up, and the viscosity reduction becomes irreversible (plastic). The effects tend to be greatest in the vicinity of injection wells where the fluid velocity is greatest, and so is the shear rate.

The flow of the polymer solution through the porous medium is assumed to have no influence on the flow of the hydrocarbon phases. The standard black-oil equations are therefore used to describe the hydrocarbon phases in the model.

The viscosity terms used in the fluid flow equations contain the effects of a change in the viscosity of the aqueous phase due to the presence of polymer and salt in the solution. However, to incorporate the effects of physical dispersion at the leading edge of the slug and also the fingering effects at the rear edge of the slug the fluid components are allocated effective viscosity values that are calculated using the Todd-Longstaff technique.

Adsorption is treated as an instantaneous effect in the model. The effect of polymer adsorption is to create a stripped water bank at the leading edge of the slug. Desorption effects may occur as the slug passes. The adsorption process causes a

reduction in the permeability of the rock to the passage of the aqueous phase and is directly correlated to the adsorbed polymer concentration. In order to compute the reduction in rock permeability, it is required to specify the residual resistance factor (RRF) for each rock type.

The dead pore volume (1st argument of the PLYROCK keyword) must also be specified for each rock type. It represents the amount of total pore volume in each grid cell that is inaccessible to the polymer solution. The effect of the dead pore volume within each cell is to cause the polymer solution to travel at a greater velocity than inactive tracers embedded in the water. This chromatographic effect is modeled by assuming that the dead pore space is constant for each rock type.

Non-Newtonian rheology behavior of polymers can be modeled in two ways in eclipse-

Shear thinning model: Shear thinning of polymer that has the effect of reducing the polymer viscosity at higher flow rates is considered. It assumes that shear rate is proportional to the flow viscosity. This assumption is not valid in general in reservoir simulations, for example, a given flow in a low permeability rock will have to pass through smaller pore throats than the same flow in a high permeability rock, and consequently the shear rate will be higher in the low permeability rock. But in a single permeability reservoir this assumption is probably reasonable.

The second model is the Herschel-Bulkley model that can be used to model shear thinning and thickening as well as yield stress, dependent on polymer concentration[10].

3.3 Alkaline Model

Alkaline flooding requires the injection of alkaline chemicals (lye or caustic solutions, that is high pH solutions) into a reservoir that react with petroleum acids to form in-situ surfactants that help release the oil from the rock by reducing interfacial tension, changing the rock surface wettability, and spontaneous emulsification. The oil can then be moved more easily through the reservoir to production wells.

Alkaline flooding is usually more efficient if the acid content of the reservoir oil is relatively high.

When used in conjunction with surfactant and polymer to perform an Alkaline-Surfactant-Polymer (ASP) flooding, the alkaline can reduce the adsorption of both surfactant and polymer on the rock surface, therefore enhancing the effectiveness of the surfactant and polymer drive.

E100 features a simplified model that does not take into account the in-situ surfactant creation and the phase behavior and this to provide an easy way to take into account some effects of the alkaline on an ASP flooding performance. The focus here is to provide the user with some facility to analyze the effect of the alkaline on the water-oil surface tension and adsorption reduction of surfactant and polymer[10].

4. Simulation Methodology and Input Data

4.1 Simulation Methodology

Norne benchmark case is a real field black-oil model for an oil field in the Norwegian Sea. The grid is a faulted corner-point grid, with heterogenous and anisotropic permeability. The model included dissolved gas, vaporized oil, transmissibility multipliers, pressure-dependent porosity and transmissibility, end-point scaling for relative permeability and capillary pressure. History-matching of production and pressures has already been done and well controls that change throughout the simulation schedule have also been included.

To look at the feasibility of application of ASP flooding in Norne field, the total production rates and hence the overall recovery shall be discussed. It is not possible to compare different cases if the same history matching controls has been applied in the new simulations. Hence as a first step the maximum filed production rates are allowed to produce without any constrains on the total production rate of the field.

4.2 Model Description

Norne field simulation model available on www.opm.org has been used for the application and of ASP flooding simulations in Eclipse 100 and tNavigator.

Norne model has a total of 113,344 simulation grids, 46 grids in x- direction, 112 grids in y-direction and 22 in z-direction. 44927 of them are active and the remaining are inactive. The maximum and minimum points are located at depth 2439m and 3090m respectively and the average block sizes are 100m x 95m x 10m in x, y and z directions.

4.3 Fluid Contacts

Reservoir has been divided into five FIP (fluid in place) regions. The gas oil contacts and oil water contacts have been shown in Table 4.1. Corresponding bubble points along with the solution gas in the undersaturated region above the bubble point have also been tabulated.

	GOC (m)	OWC (m)	Pb (bar)	Pb (atm)	Rsi @ Pb	Thickness
Region1	2582.0	2692.0	268.6	265.0	120.25	110.0
Region2	2500.0	2585.5	263.4	260.0	94.5	85.5
Region3	2582.0	2618.0	269.5	265.9	120.25	36.0
Region4	2200.0	2400.0	236.9	233.8	94.5	200.0
Region5	2585.0	2693.3	268.8	265.3	120.29	108.3

Table 4.1: Gas-Oil and Oil-Water Contacts

4.4 Fault zonation

Figure 4.1 shows the fault zonation with the location of the wells. Total 36 wells are there of which 27 are production wells and the remaining 10 are the injection wells.

4.5 Injection Wells

There are nine injection wells. Five of them are exclusively water injection wells and the remaining four are water and gas injection wells. Over the almost 10 years of production history since 1997 a total volume of 102.6 MSm^3 of water has been injected from all the nine wells. From the five only water injection wells a total volume of 73.9 Sm^3 water has been injected i.e. almost 72 % of the total water injection from the field.

These water injection wells have been selected to verify the feasibility of ASP flooding in the Norne field.
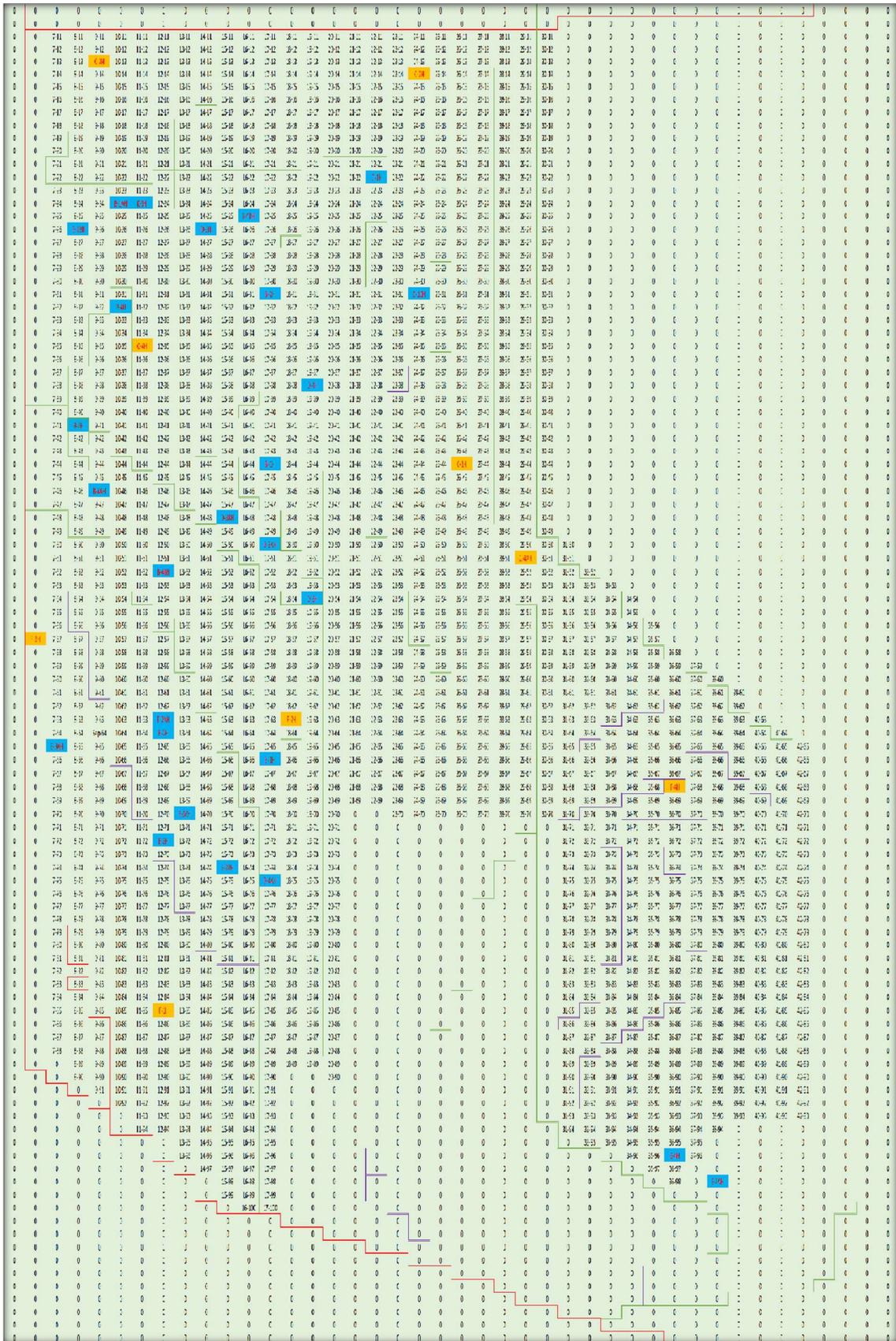
Figure 4.1: Fault Zonation and Location of Wells

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5. Results and Discussion

5.1 Base Case

The initial model that is used for this purpose study had already been history matched. The model did not contain the original pressure history of the field and the original well Wise BHPs. Hence the pressures predicted in the initial Eclipse data set have been considered to be true.

For the purpose of study it is assumed that the surfactant chemicals are being injected from the first day when the water injection starts; and the actual water injection rates have not been changed. Those wells that are used for gas injection were not used for chemical injection.

The injection rates of the chemicals are random but loosely based upon the literature published values (Refer section 2.7). The conditions in the very well designed projects are completely different from this test case. The production and injection well patterns and the spacing between the producer and the surrounding injectors were very well designed.

As a base case, the well production controls that had been used for the sake of history matching, came in with original Eclipse data set, have been released and the production target of the overall field has been set to 23 MSm^3. Various production scenarios have best checked along with the average field pressures; production rates of 20, 25, 30 and 35 MSm^3 have been checked. Pressure is depleting very fast when the production rates are higher and defeating the basic purpose water injection that was employed in the field. The field average pressures are not depleting so fast when the production field maximum production rate is set 23 MSm^3. The reason why a relatively longer plateau has been sought to set the base case is it is very easy to look at the length of the plateau if an EOR application is working are not.

Figure 5.1 and Figure 5.2 shows the different production scenarios of base case.
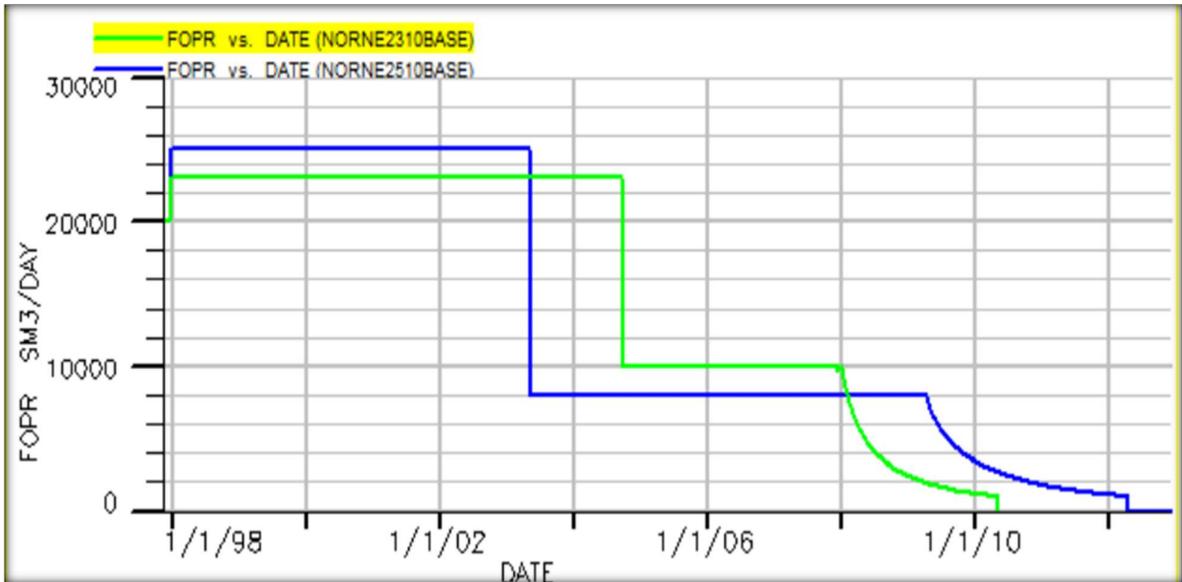
Figure 5.1: Plateau Comparison – Production Rate Profiles
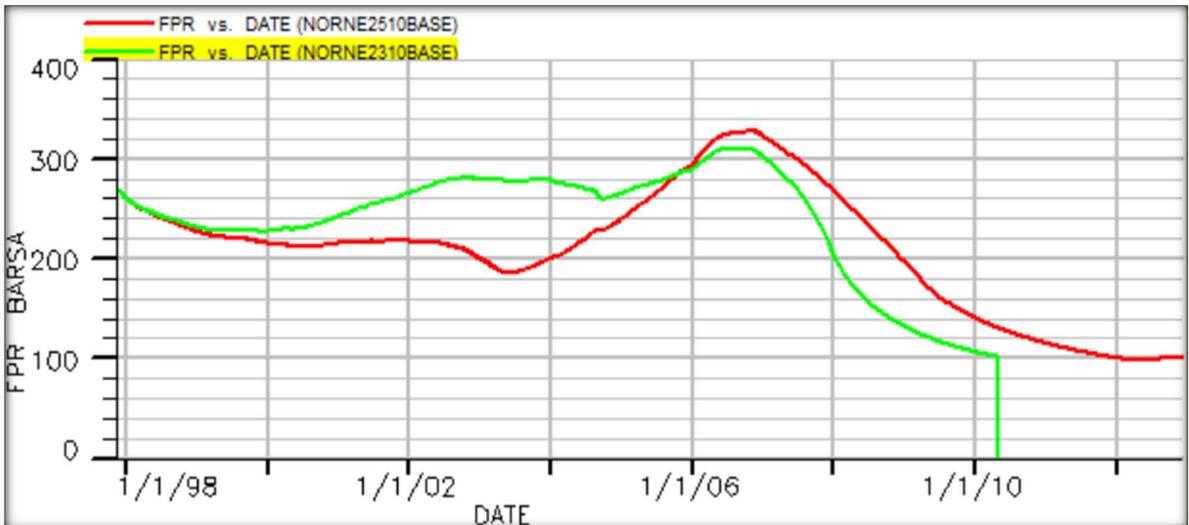
Figure 5.2: Plateau Comparison – Average Reservoir Pressures

It is obvious and also can be observed that 20 MSm^3 production rate gives the longer plateau production rate than the other scenarios. For 20 MSm^3 production the field average pressures are higher than the other scenarios.

For the purpose of this study analysis, a production profile with a plateau production rate of 23 MSm^3 has been selected.

5.2 Polymer Model

The purpose of adding polymer to the water during water injection is to have a better mobility ratio that slows down the water. In ideal scenario displacing

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saturation water front shall have a piston like movement to displace efficiently the oil in front of it.

For this model, initially higher viscosities as high as 50 cP of polymer have been selected and all the polymer flood runs resulted in very shorter plateau production period and lesser recovery. It was a very strange result and hence few test cases were run without polymer by changing the water viscosity and see how the production responding.

The initial water viscosity that was used in the Norne model is 0.318 cP. This value is very low as far the reservoir waters are concerned, but also very low when the normal water viscosities are concerned. All the runs even with a water viscosity of 1.0 cP resulted in inferior production scenario.

Figure 5.3 though Figure 5.5 shows the production rates and pressures with various viscosities.
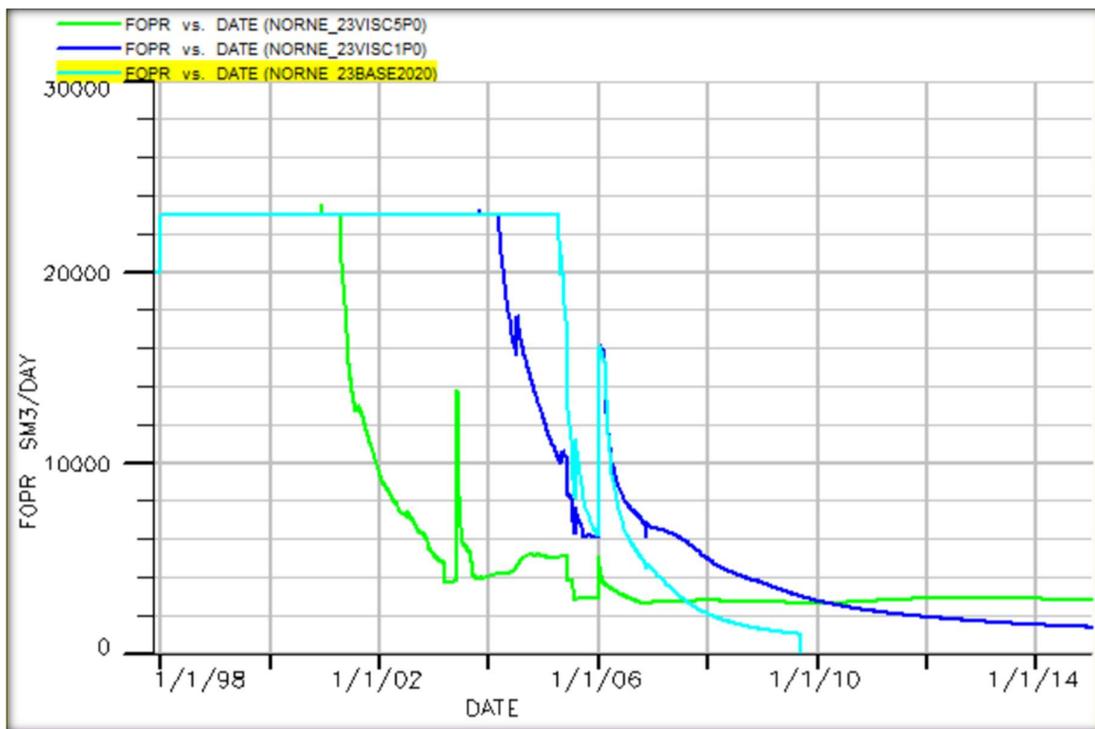
Figure 5.3: Oil Production rates – Different Viscosities
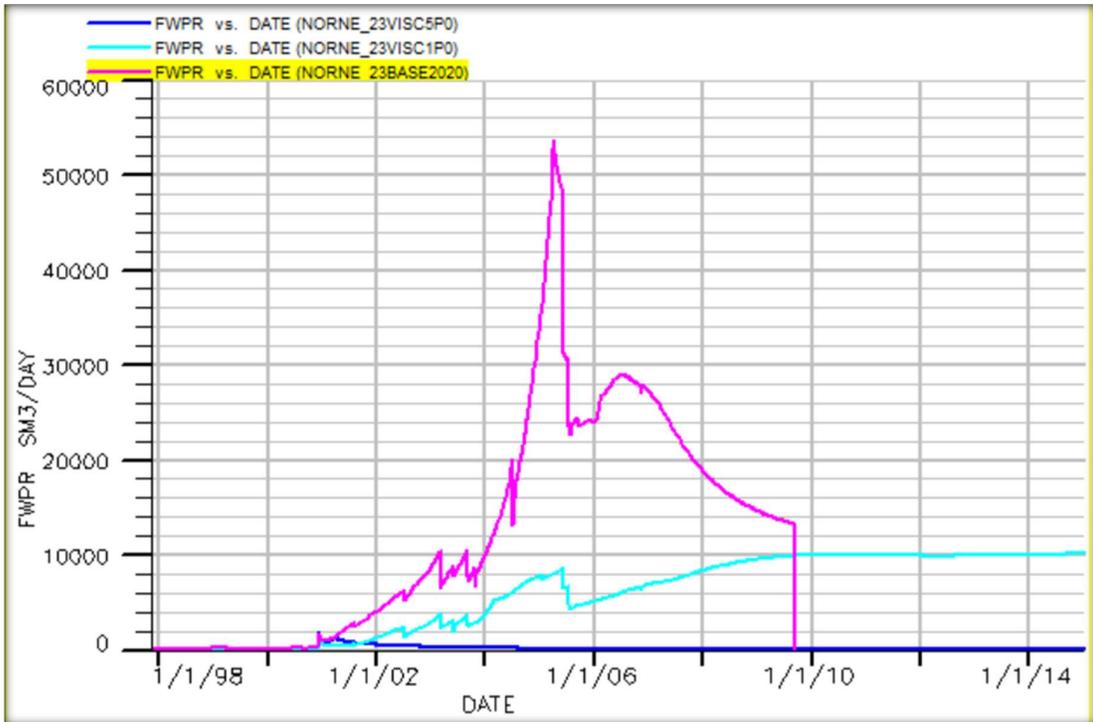
Figure 5.4: Field Water Production Rates – Different Viscosities
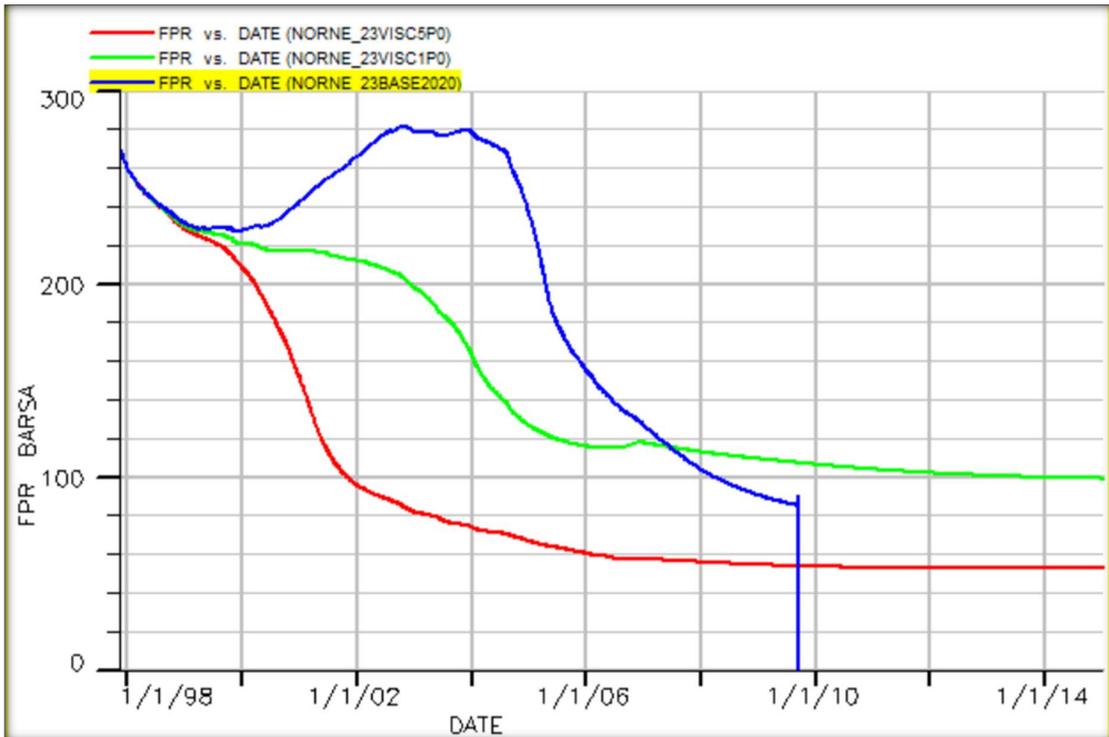
Figure 5.5: Field Average Pressures – Different Viscosities

Upon the careful scrutiny of the field permeabilities it is observed that the simulation model has divided the field in 22 layers with large variation in vertical permeabilities.

There are 10% of total grid blocks have permeabilities as high as 1000 cP and there are almost 30 to 40% grid blocks with permeabilities of about 150 cP. The remaining 50% of the grid blocks have very low relative permeabilties about 50 cP.

Figure 5.6 shows a block diagram of permeability distribution.
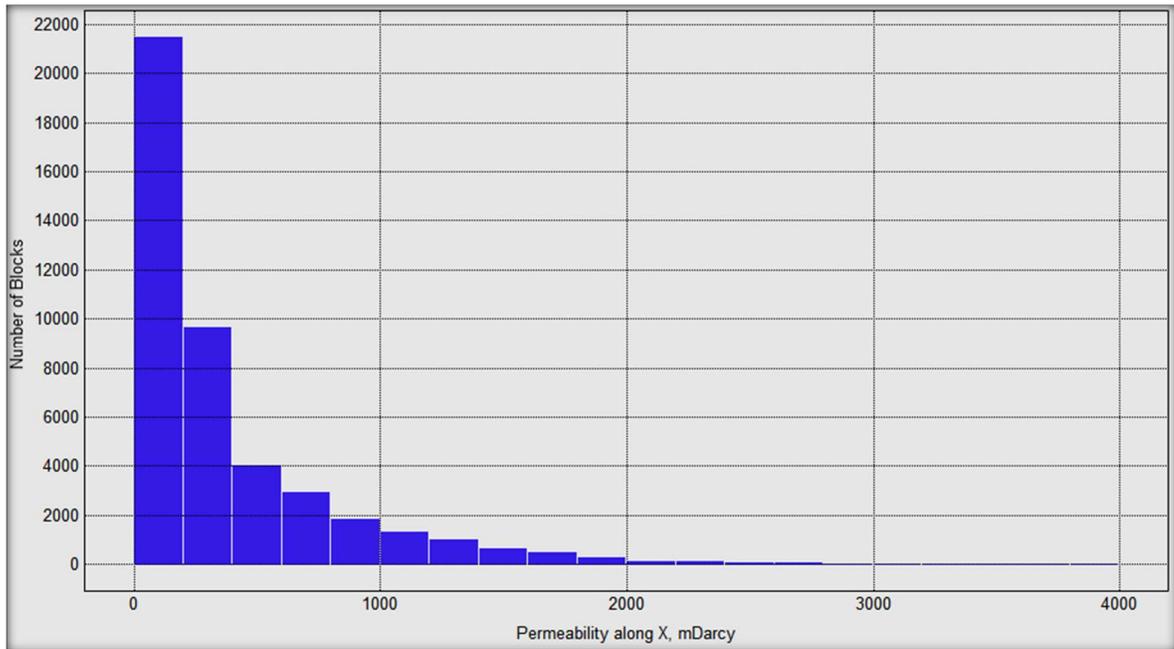
Figure 5.6: Block Diagram of Permeability Distribution in X and Y Directions

Upon consideration of the fact that the reservoir has both high and low permeability zones, it makes perfect sense to have lower recovery and inferior production scenario when the viscosity of the water is increased.

When the viscosity is increased by adding polymers, the lower permeable zones will not let the heavier molecules (heavier viscosities) to enter the very interior regions that can only accessed by very light fluids. So, a portion of the flow path volume is restricted to the heavier water that makes the heavier water to travel through a less restricted and lesser volume to travel. Hence the water velocities became higher and it is acting exactly against our aim of having lower velocities and favorable mobility ratios. This reduced mobility ration is increasing the fractional flow of water and thus the reservoir is producing very higher water rates when compared to the base case of no polymer injection or no viscosity addition to the water.

Since the viscosity is not helping to increase the production, it is decided not to use the polymer in further runs. Actually, the polymer viscosity multiplier has been taken as one in the models.

5.3 Alkaline Model

Actual purpose of the Alkaline injection is to generate the surf in the reservoir itself when the injected alkaline chemicals react with the reservoir acid compounds. In E100, Alkaline model is a very simple one and the in-situ surfactant production is not included.

Alkali only helps the reservoir rock not to adsorb the surfactant chemicals. So, indirectly it helps the surfactants to operate more efficiently without loosing to the reservoir. Alkali also induces a small effect on the viscosity of water, but in this study the viscosity multipliers for the alkali were made one. So, no effect on water viscosities.

5.4 Surfactant Models

As explained above, in order to nullify the effects of higher viscosity the viscosity multipliers are made to one and the actual surfactant viscosity is equated to the original water viscosity in the original Norne model.

Three different injection rates of ASP chemicals have been injected to see if production and recovery are getting better.

Designing of ASP flooding is generally done in three stages.

1) Laboratory analysis of the core and modelling of history matching of the core flooding results
2) Verification at the pilot level – Same process is repeated ay pilot level with pattern flooding
3) Simulation and implementation at the reservoir level

The injection chemicals and the required injection rates are selected from the laboratory experiments and subsequent testing and study analysis.

For the purpose of this study, the average values published in the literature have been taken as the basis and three random injection flow rates have been considered within the same order. The literature published injection rates in the main slug are of 1.25 wt% Alkali (A), 0.27 wt% Surfactant (S), and 0.135 wt% Polymer (P). When calculated to the Sm^3/d with an water density at surface conditions of 1038 kg/m^3, the injection rates correspond to the case of low injection rates as described low. Since the wells are not properly patterned it is considered to inject higher volumes than the field average volumes. Medium and High injection case are 1.5 times and 2 times higher than the low case injection volumes[3].

1) Low injection rates
- Alkali   = 12.9 kg/Sm^3
- Surfactant   = 2.79 kg/Sm^3
- Polymer   = 1.39 kg/m^3

2) Medium injection rates
- Alkali   = 19.4 kg/Sm^3
- Surfactant   = 4.2 kg/m^3
- Polymer   = 2.1 kg/m^3

3) High injection rates
- Alkali   = 25.8 kg/Sm^3
- Surfactant   = 5.6 kg/Sm^3
- Polymer   = 2.8 kg/m^3

5.3 ASP Flooding Results

All these four cases have been compared against the base case where there was no injection of chemicals.

Figure 5.7 shows the oil production rates along the life of the field. As discussed, it can be observed that in the cases the maximum production is curtailed at the plateau rate of 23 MSm^3/d. The shortest plateau period of production belongs to the

no injection scenario. The length of the production plateau increases in the same order as the injection rates of the chemicals are increased. Only three cases of injection scenarios have been shown here, since there is not much incremental recovery after certain injection rate. This is possible due to the fact that the oil saturation in the reservoir might have been reached to the residual oil saturation.
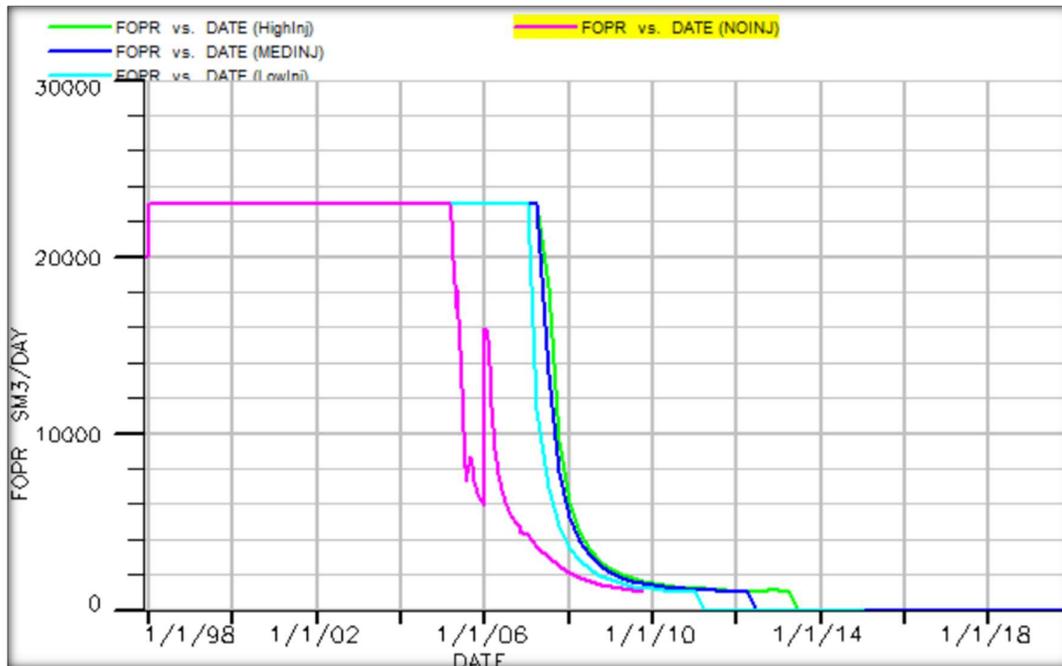

Figure 5.7: Oil Production Profiles

Figure 5.8 shows the water production rates along the life of the field. Water breakthrough starts early in the case of no chemical injection and produces more water than the rest of the cases. Water production rate decreases as the rate of the chemical injection increases. This is because since the surface tension between the oil and water is reduced, oil (non-wetting phase) started flowing ahead of the water leaving the wetting phase(water) behind.
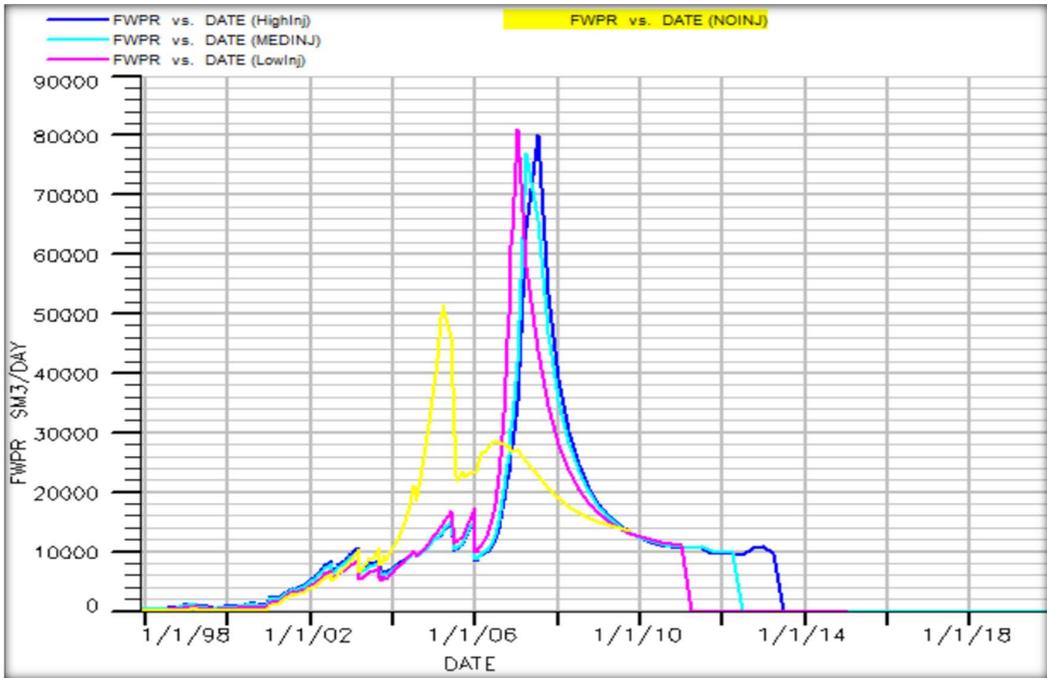
Figure 5.8: Water Production Profiles

Figure 5.9 shows the total water production in MSm³ for all the three cases. As discussed above as the water production rate decreases with increasing chemical injection rate the cumulative water productions also decreases.
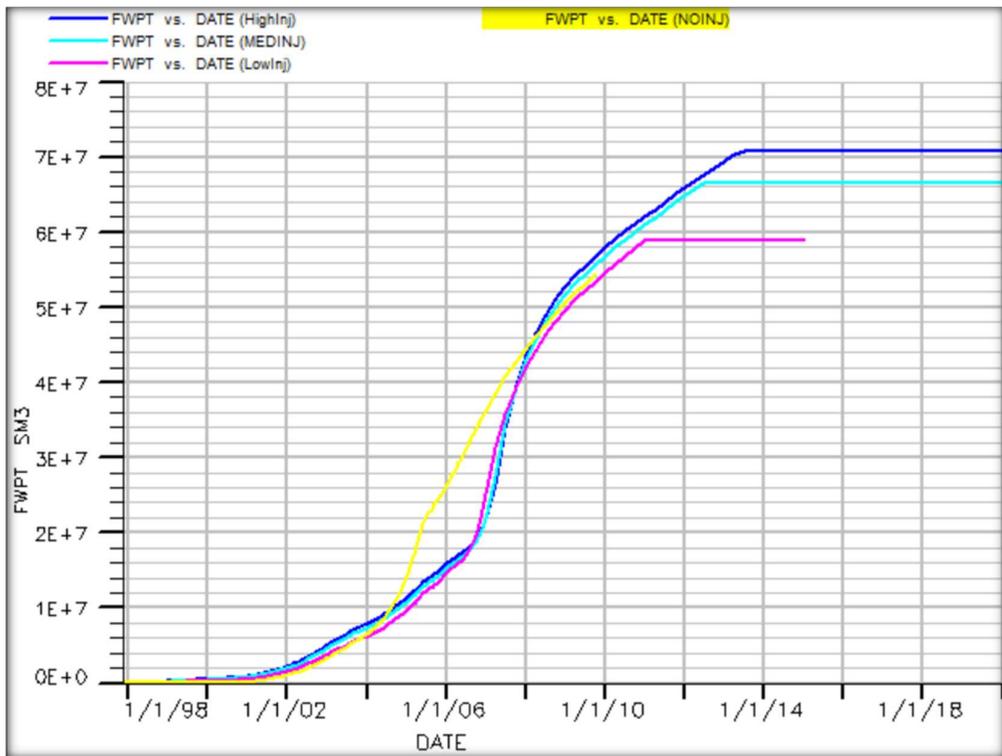
Figure 5.9: Cumulative Water Production

Figure 5.10 shows the average field pressures. Average field pressures are well maintained in case of chemical injection and are same in almost all injection rates.
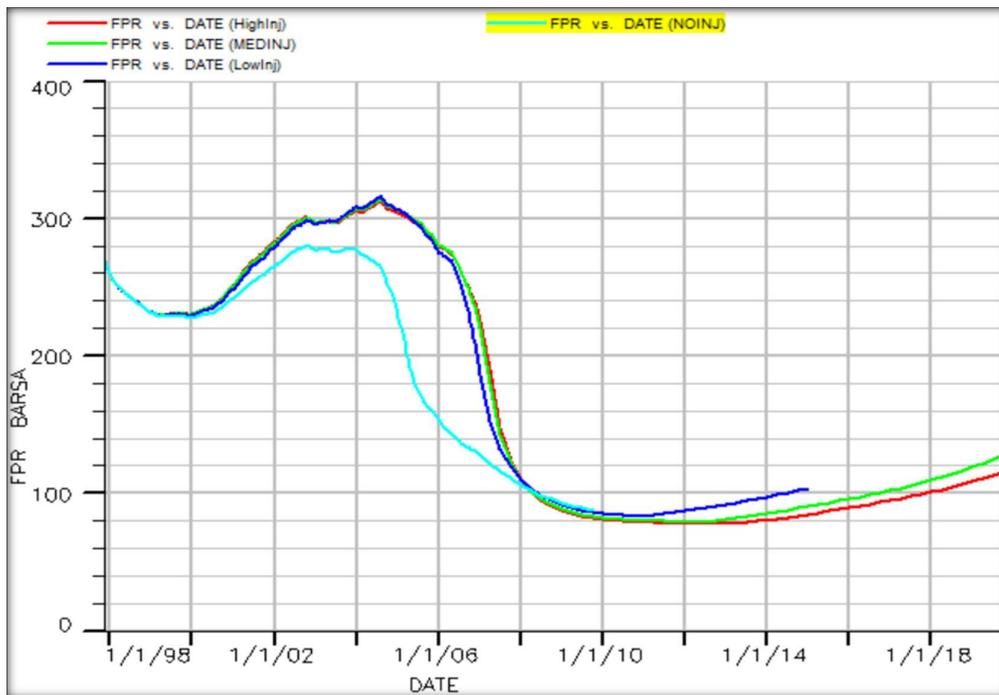

Figure 5.10: Average Field Pressures

Figure 5.11 shows the gas production rates along the life of the field. As the average field pressures fall below the saturation pressure gas production increases. The increase of gas production corresponds to the field pressures as in Figure 5.10.
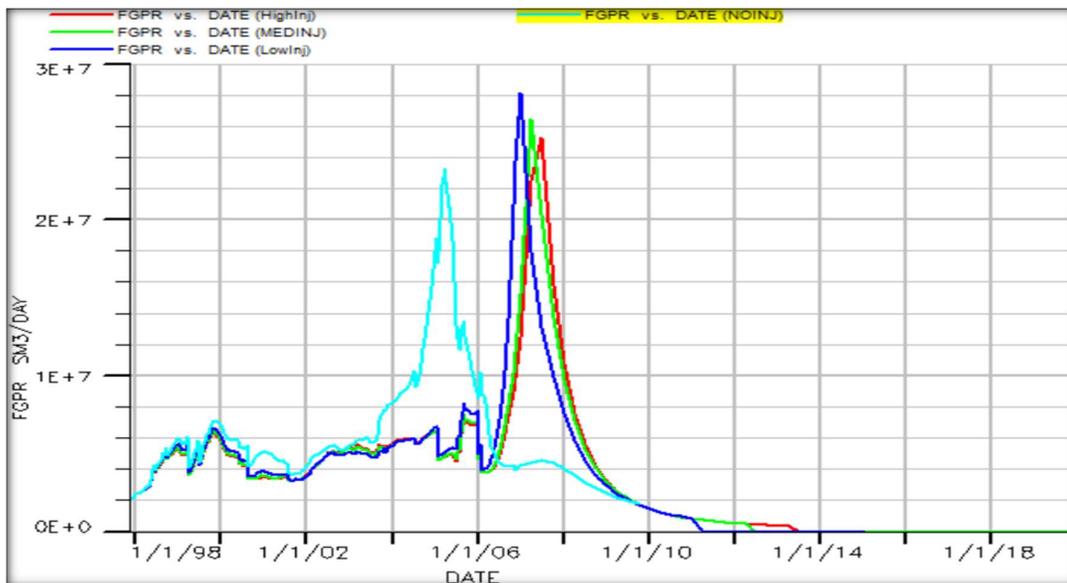
Figure 5.11: Gas Production Profiles

Figure 5.12 shows the cumulative oil production rates along the life of the field. As observed in Figure 5.7 (oil production rates), until 2007, the production rate is fixed to the plateau and then started dropping one after the other depending on the rate of chemical injection. But a same trend of falling is observed and the tail of the production is almost same in all the cases. Residual oil saturation is very low and it is almost 5%. So in all the cases, oil production in the chemical sweep zone is extended until the oil saturation drops to 5% irrespective the chemical injection. The longer oil production before the rate tapers in case of chemical injection is due to improved relative permeabilities in favor oil during the high oil saturation periods.
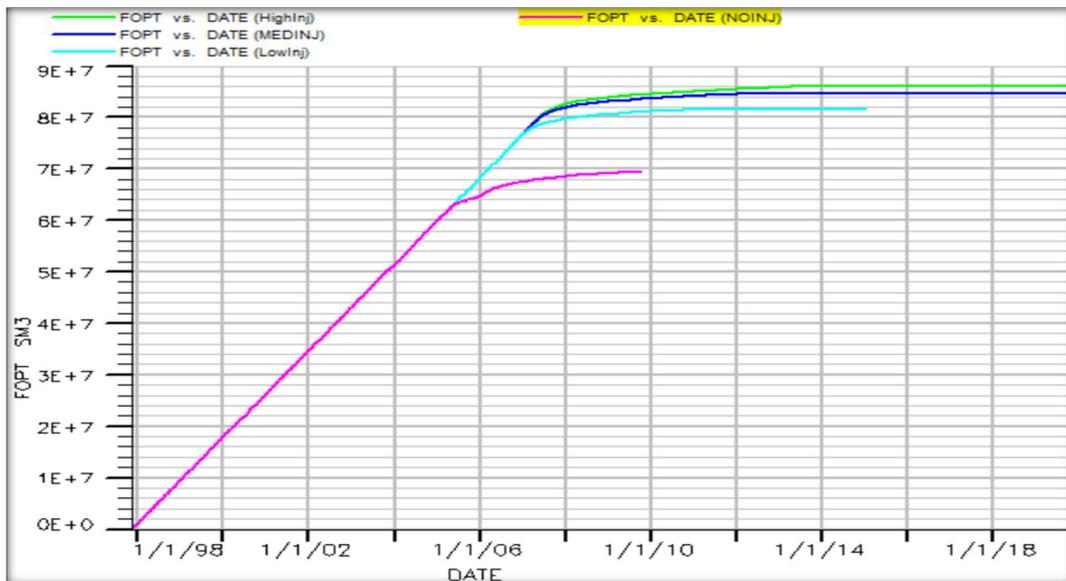
Figure 5.12: Cumulative Oil Production

Total recovery until 2010 is about 69 MSm^3 in no injection case; and the recoveries in low, medium and injection rates are 82 MSm^3, 85 MSm^{3}and 86 MSm^3 respectively.

5.4 Comparison of Eclipse 100 and tNavigator

5.4.1 Low Injection Case

Figure 5.13 shows the fluid in place volumes for both water and oil for a case of low injection rates of ASP chemicals. It can be observed that the initial estimation of both oil and water is well in agreement. During the production life, current oil in place in Eclipse and tNavigator are almost similar, but there is a difference in the current water in place volumes.
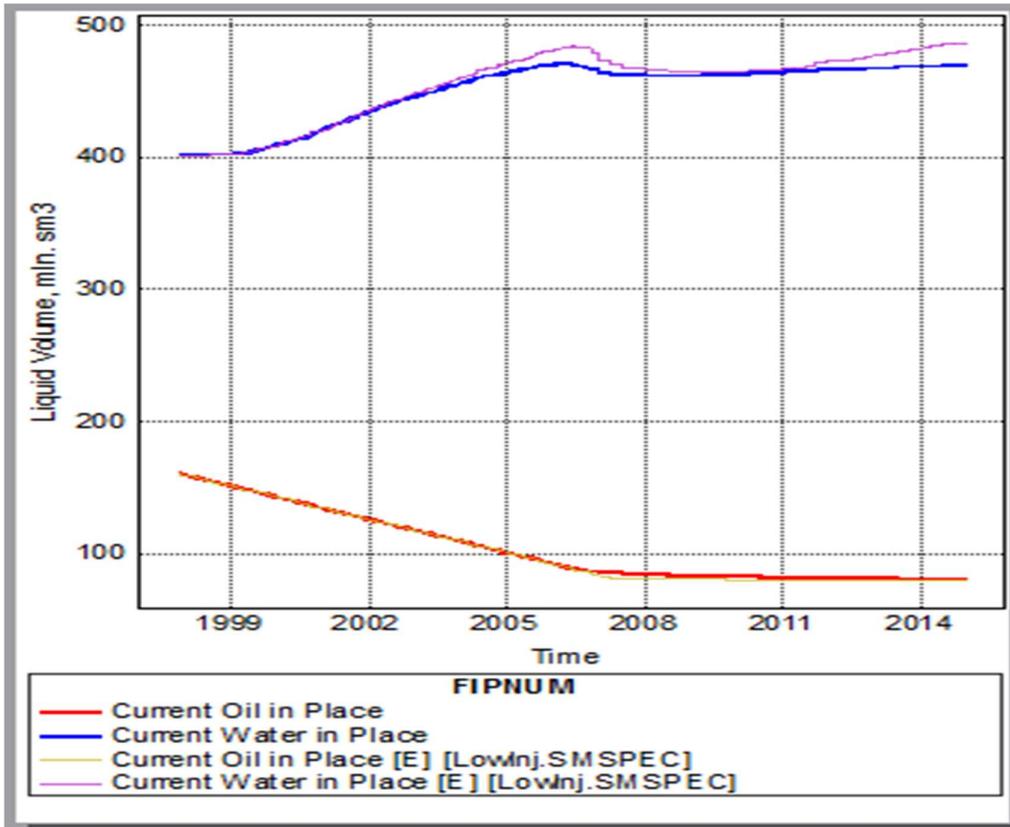
Figure 5.13: Current in Place Volumes Comparison – Low Chemical Injection Rate

Figure 5.14 shows the oil production rates in case of low injection rates of ASP chemicals. Though results are almost comparable, Eclipse predicts a little longer plateau rate than tNavigator.
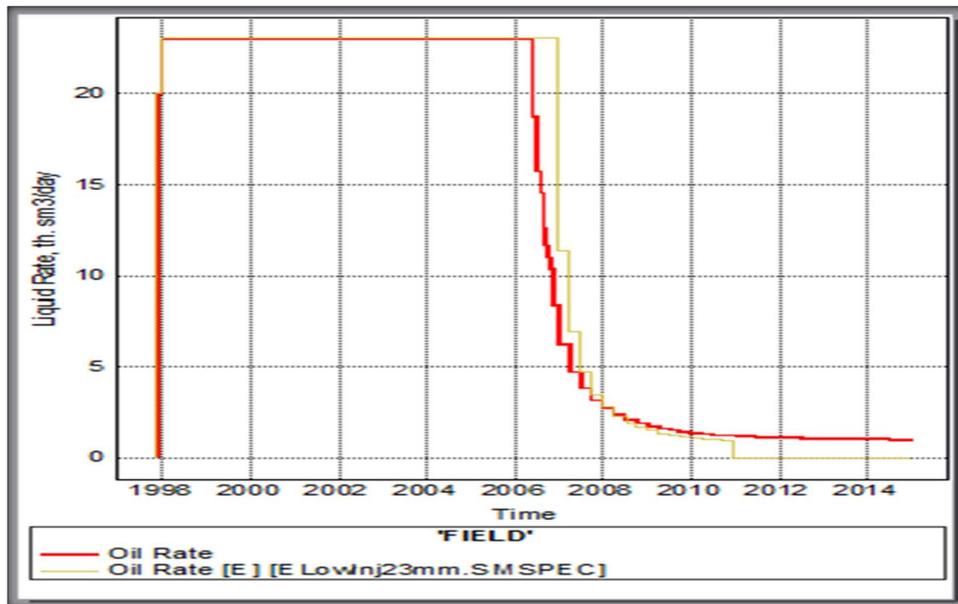

Figure 5.14: Oil Production Rates Comparison – Low Chemical Injection Rate

Figure 5.15 shows the water production rates in case of low injection rates of ASP chemicals. Eclipse and tNavigator exhibits completely different behavior in water production profile though the shape of the curve resembles each other with minor differences.


Figure 5.15: Water Production Rates Comparison – Low Chemical Injection Rate

Figure 5.16 shows the average reservoir pressures of the field in case of low injection rates of ASP chemicals. Eclipse and tNavigator exhibits completely different behavior in water production profile though the shape of the curve resembles each other with minor differences.
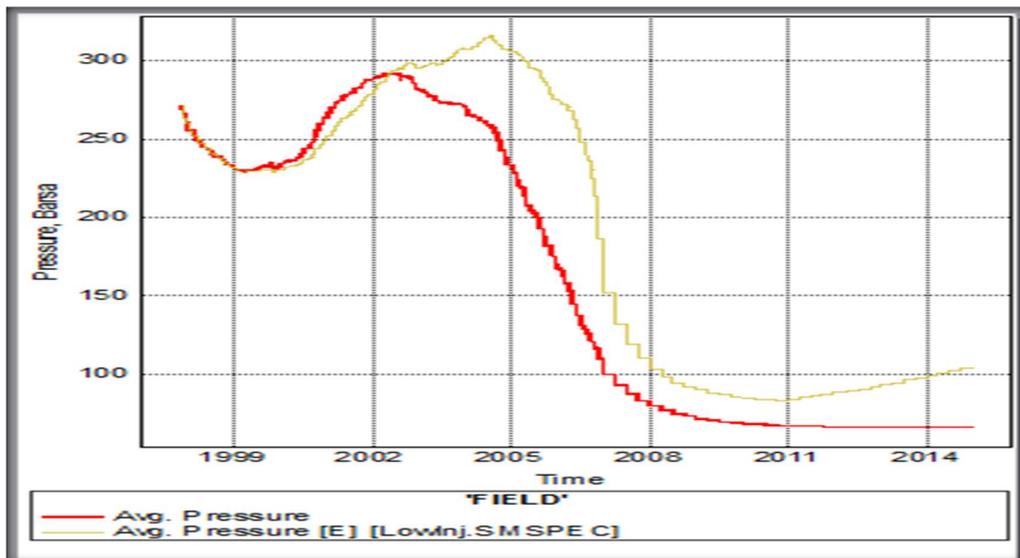
Figure 5.16: Average Field Pressures Comparison – Low Chemical Injection Rate

Figure 5.17 shows the gas production rates in case of low injection rates of ASP chemicals. Eclipse and tNavigator exhibits completely different behavior as in water producton, average field pressures and current fluid in place volumes. Upon the close scrutiny it can observed that the difference in all these parameters is due to the way tNavigator is dealing with the miscibility of injection gas. Though the keywords for solution gas, vaporization of oil have been activated in both Eclipse and tNavigator, tNavigator is treating it differently and the injection gas is not soluble into the oil phase and/or releasing the more gas than Eclipse estimation. This is the reason why Eclipse and tNavigator are not conforming in these parameters.
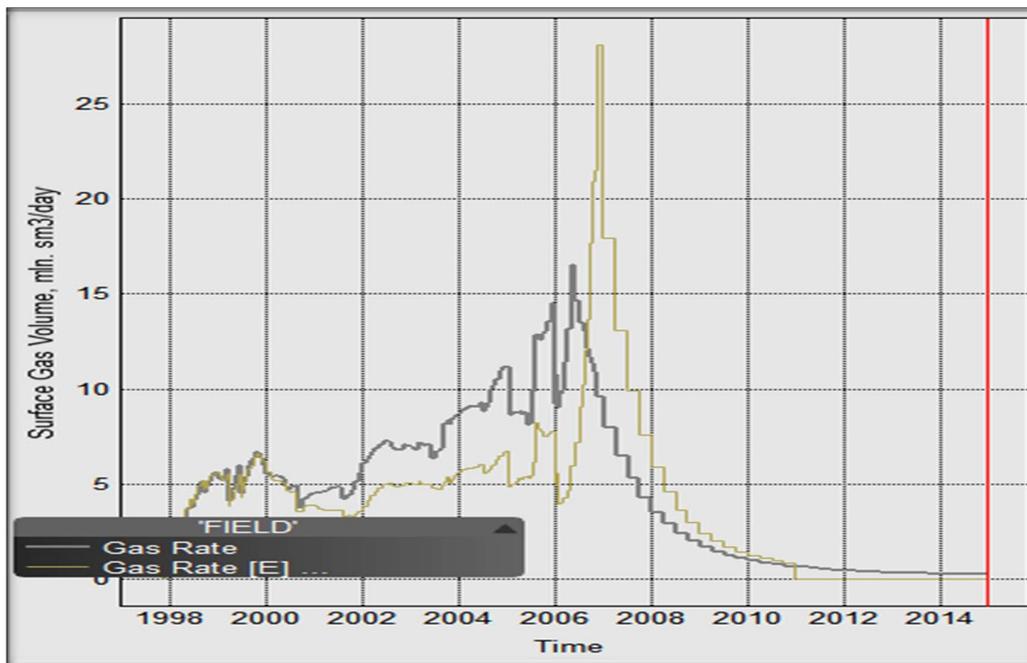

Figure 5.17: Gas Production Rates Comparison – Low Chemical Injection Rate

5.4.2 Medium Injection Rate

Figure 5.18 through Figure 5.23 show the comparison of all production parameters for a case medium chemical injection rates. All the observations are more less similar to the case of low chemical injection rates.
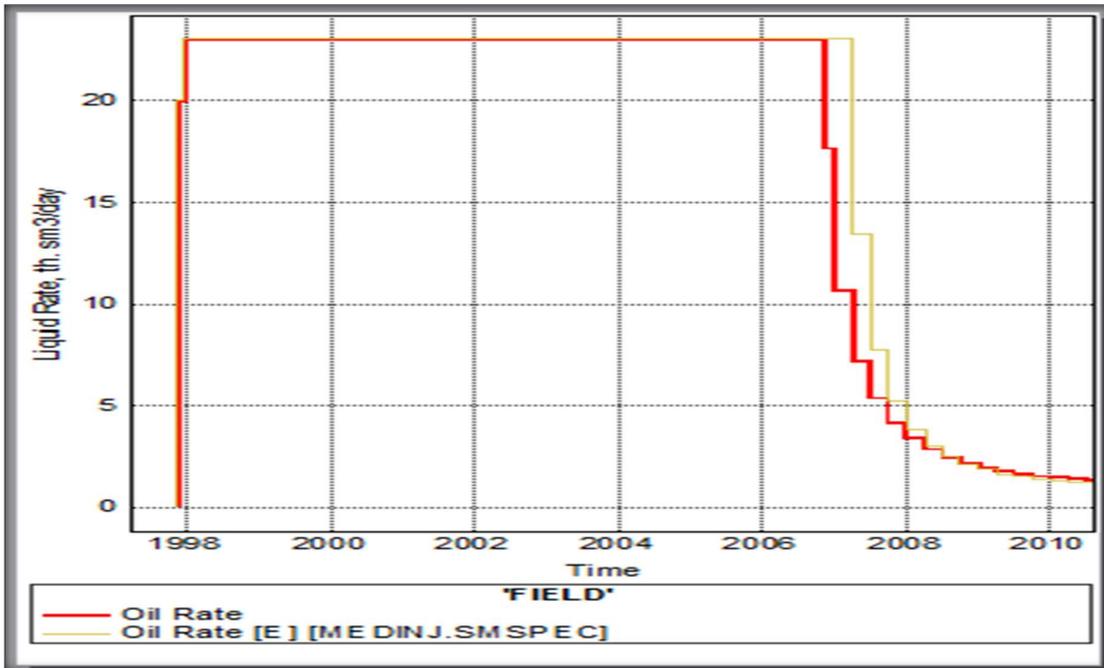
Figure 5.18: Oil Production Rates Comparison – Medium Chemical Injection Rate
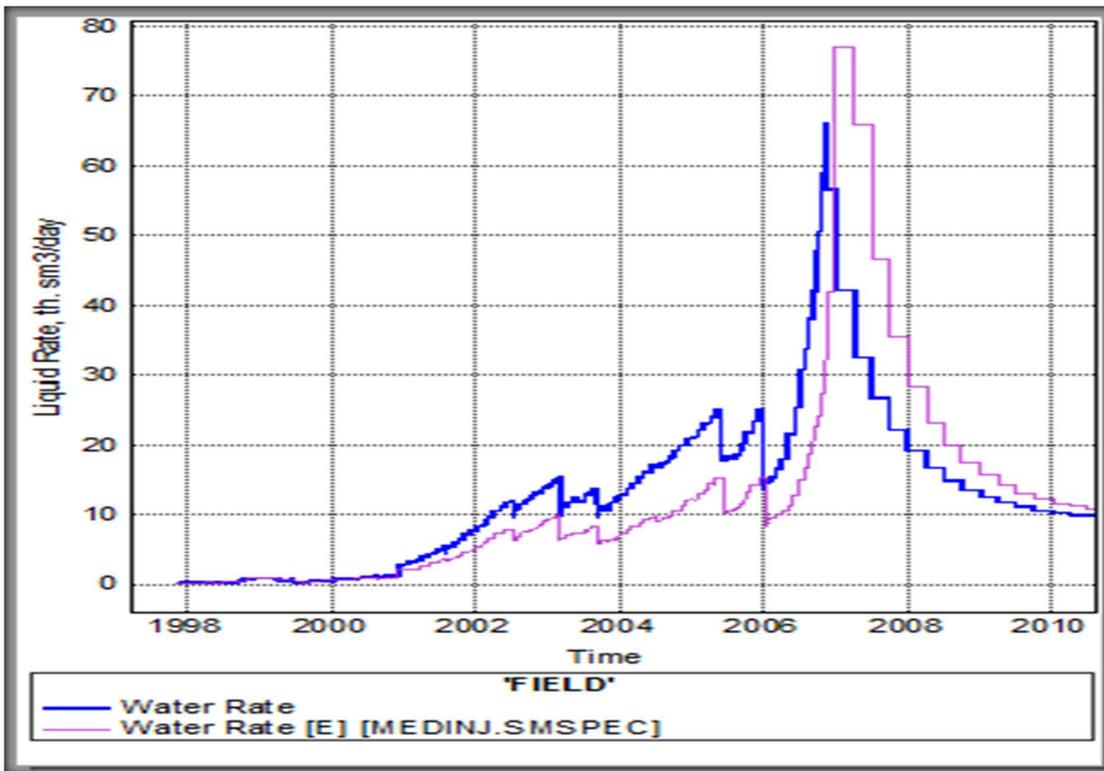
Figure 5.19: Water Production Rates Comparison – Medium Chemical Injection Rate
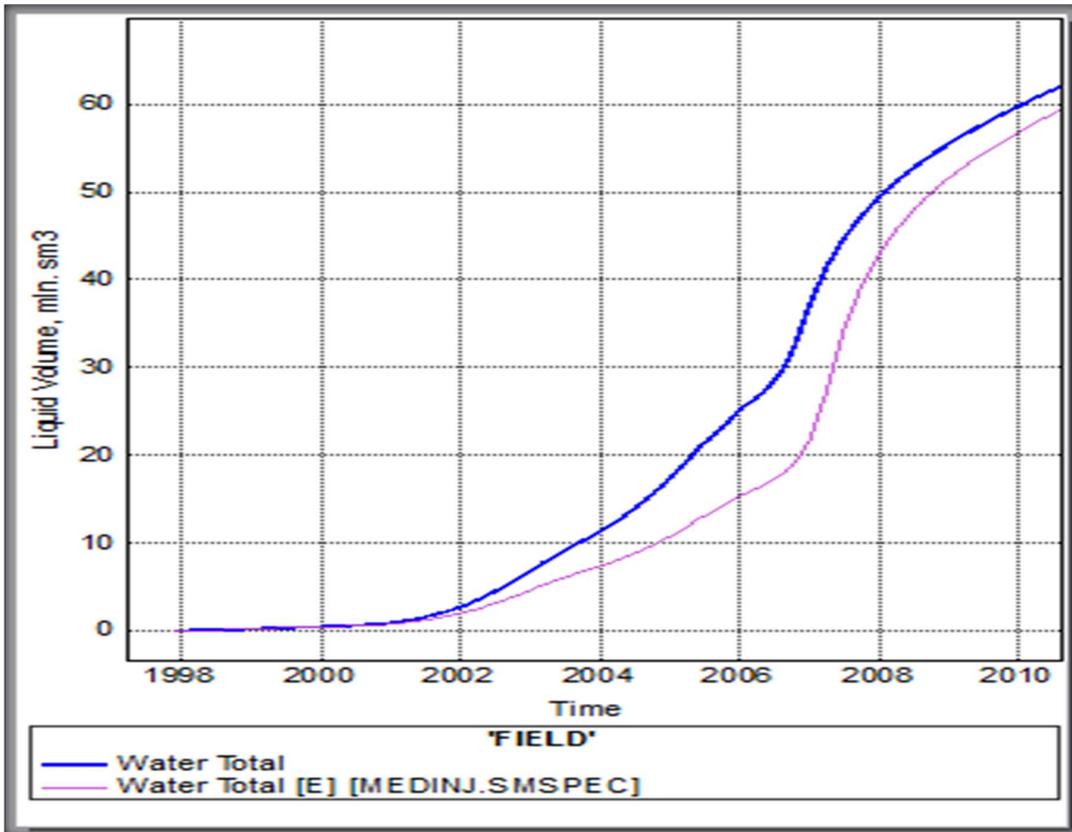
Figure 5.20: Total Water Production Comparison – Medium Chemical Injection Rate
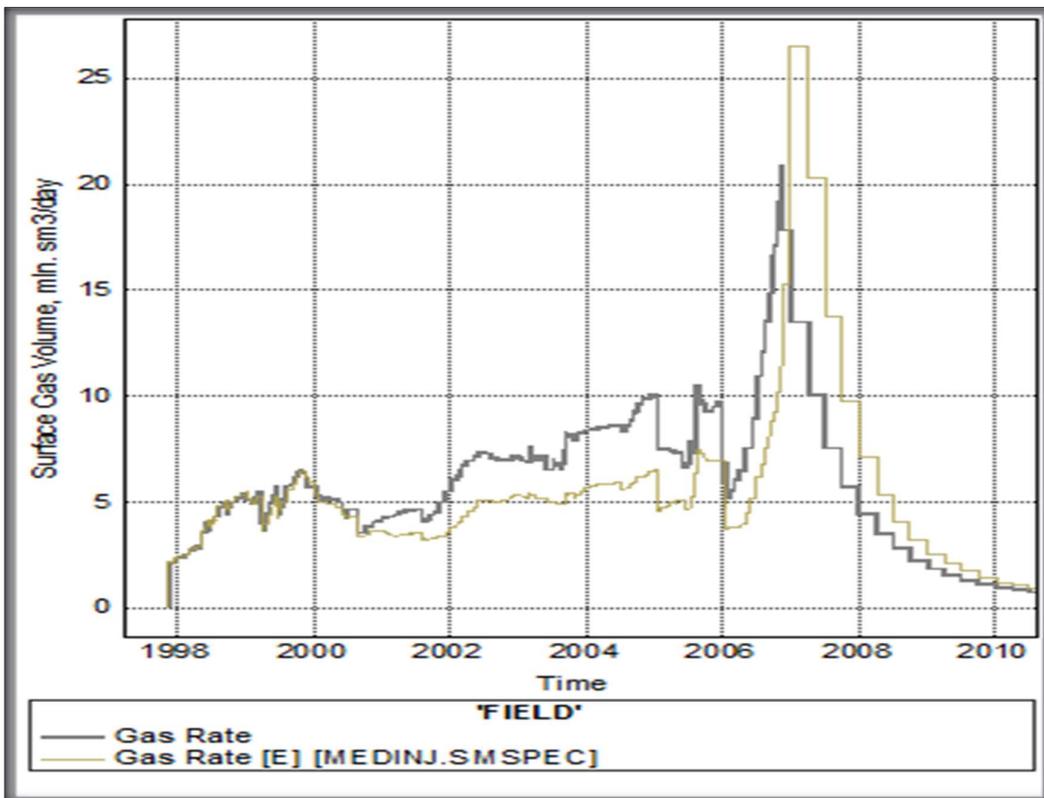

Figure 5.21: Gas Production Rates Comparison – Medium Chemical Injection Rate
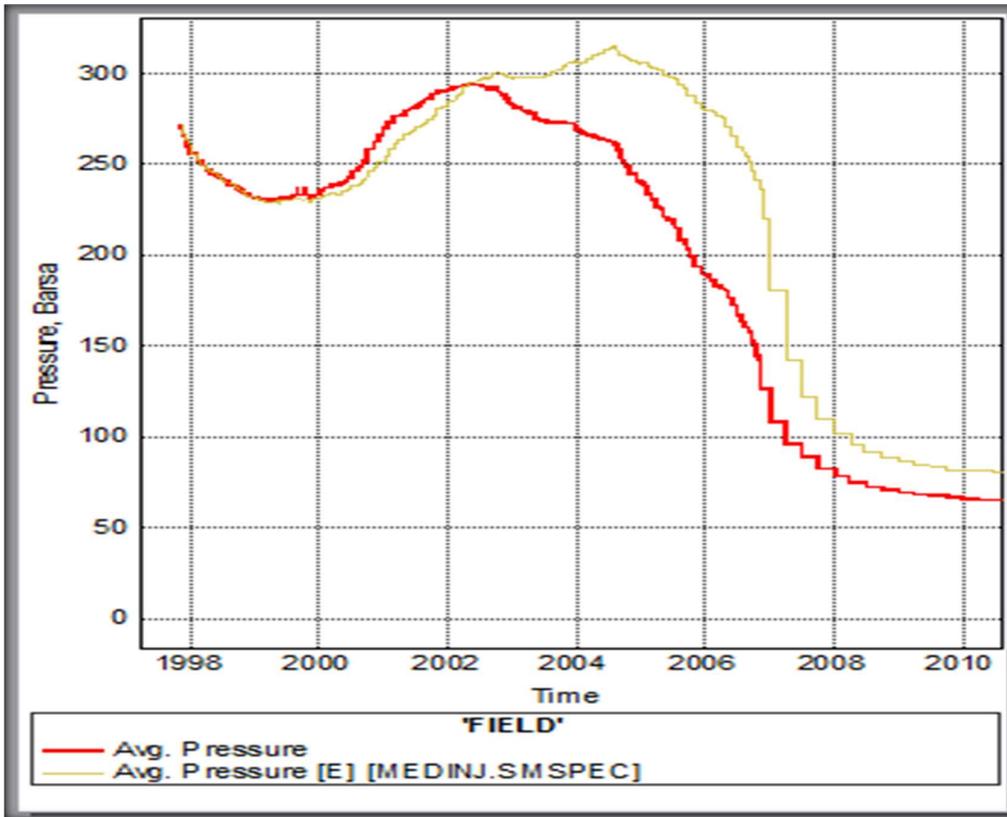
Figure 5.22: Field Average Pressures Comparison – Medium Chemical Injection Rate
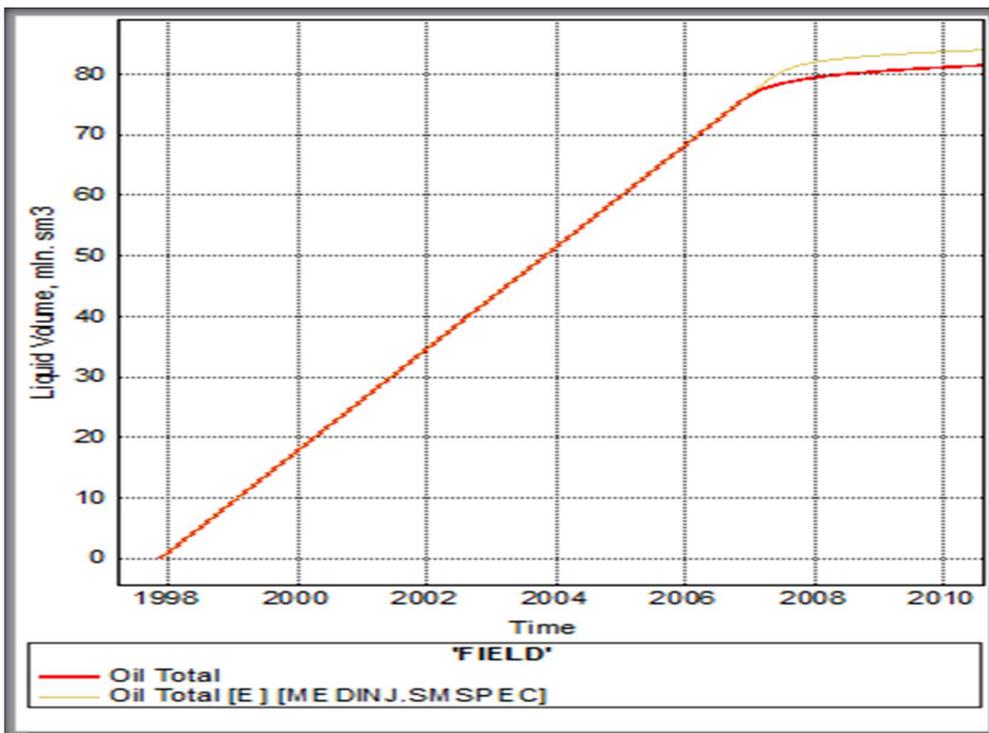
Figure 5.23: Total Oil Production Comparison – Medium Chemical Injection Rate

5.4.3 High Injection Rate

Figure 5.24 through Figure 5.28 show the comparison of all production parameters for a case high chemical injection rates. All the observations are more less similar to the cases of low and medium chemical injection rates.

Figure 5.24: Oil Production Rates Comparison – High Chemical Injection Rate
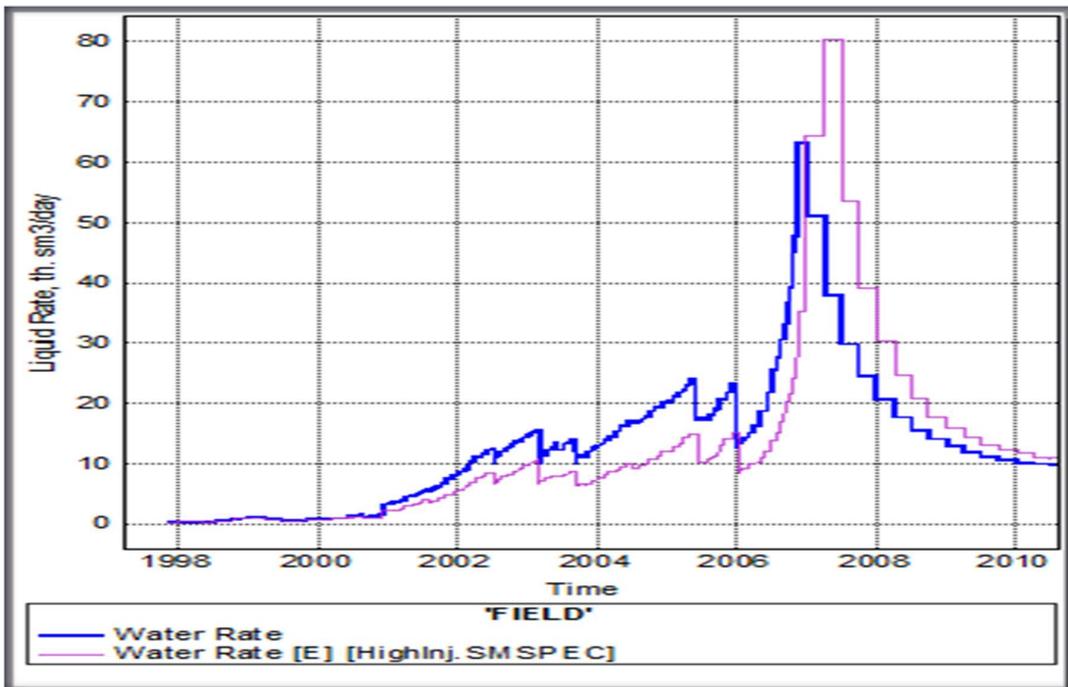
Figure 5.25: Water Production Rates Comparison – High Chemical Injection Rate
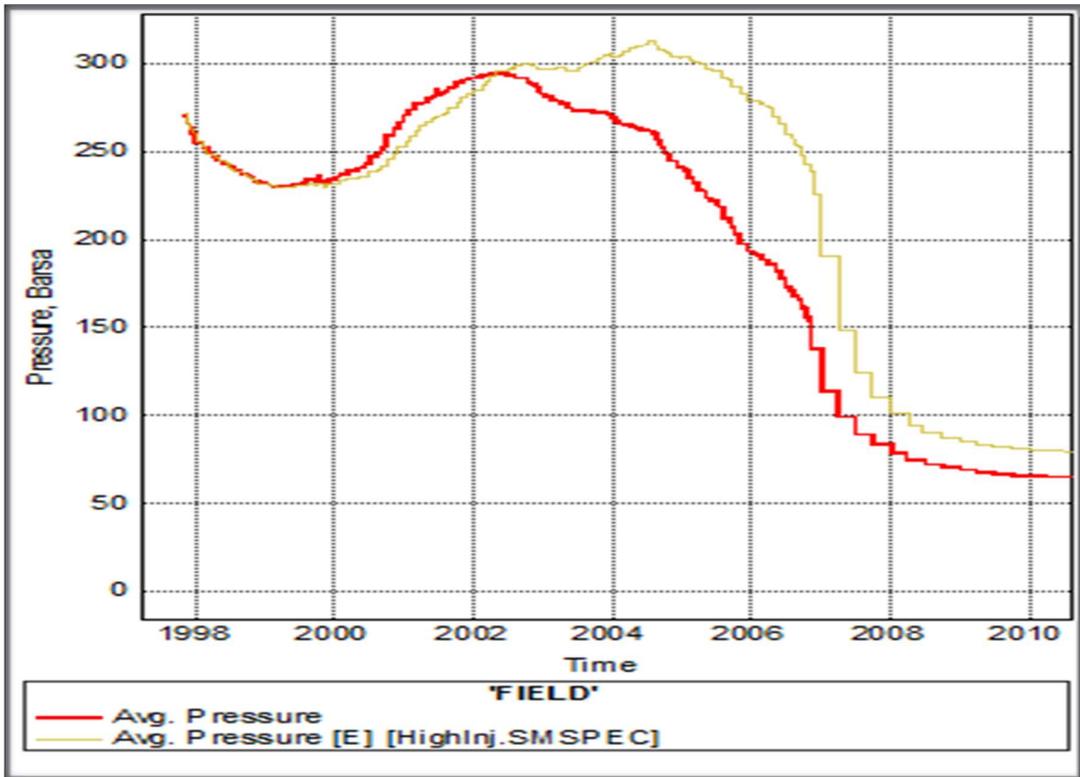
Figure 5.26: Average Field Pressure Comparison – High Chemical Injection Rate
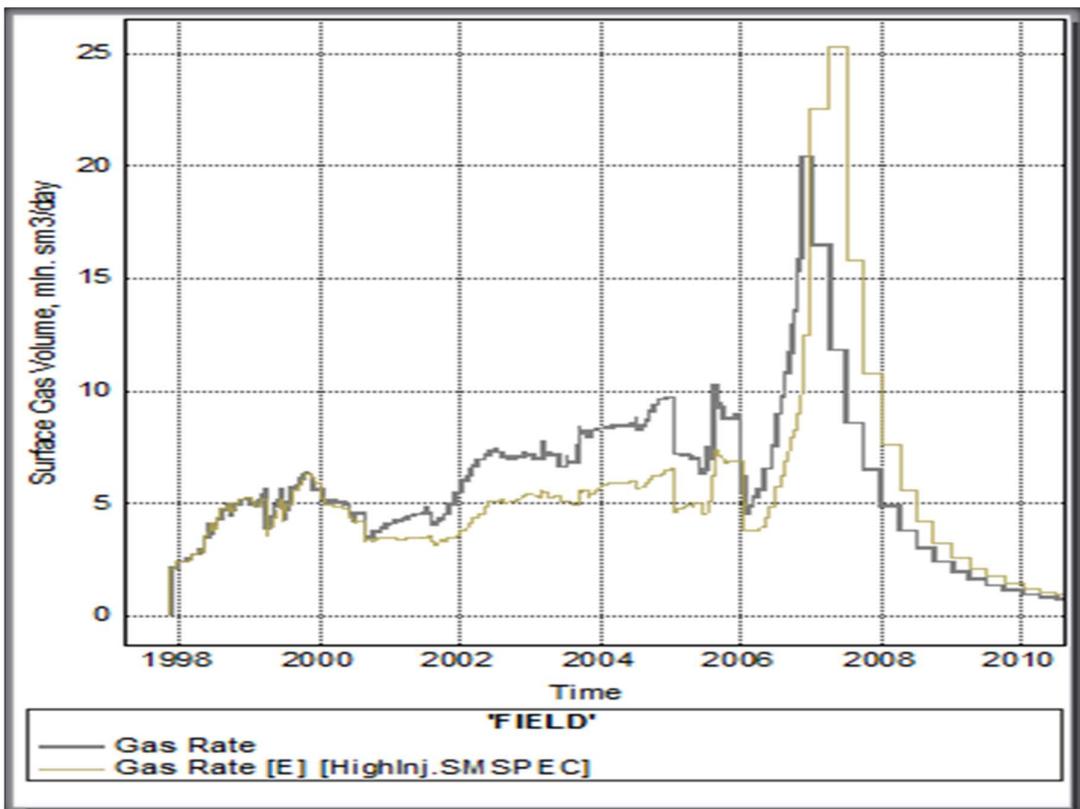
Figure 5.27: Gas Production Rates Comparison – High Chemical Injection Rate
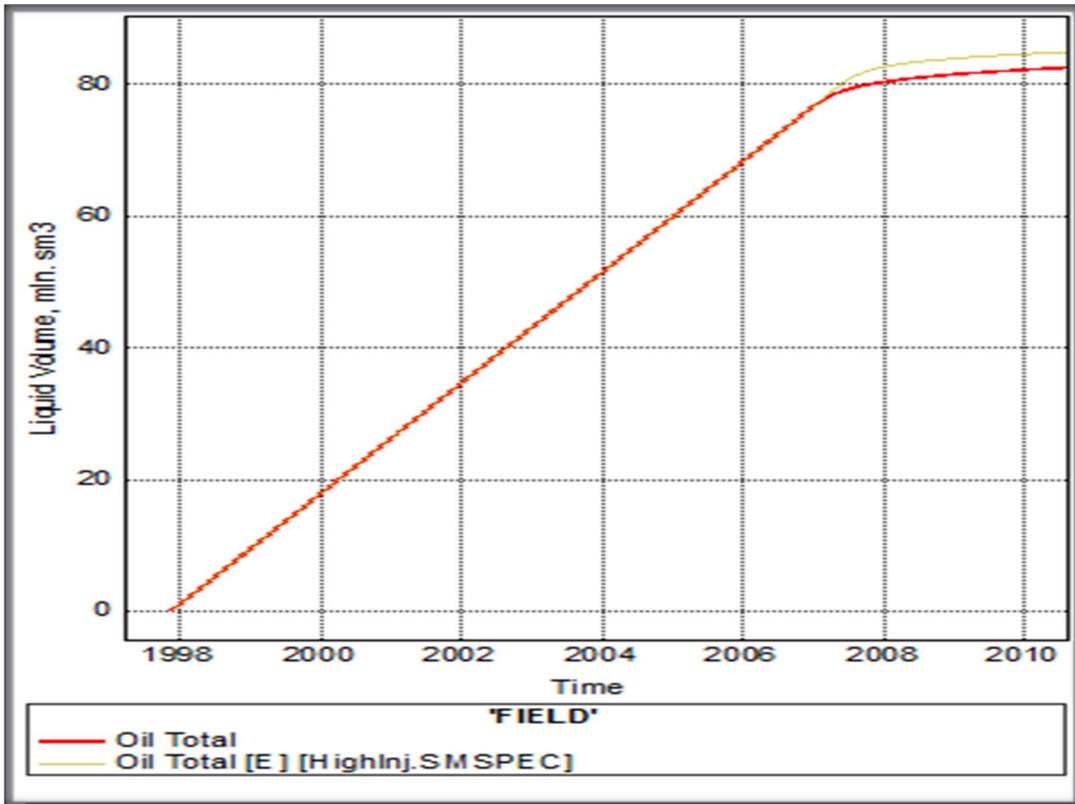
Figure 5.28: Total Oil Production Rates Comparison – High Chemical Injection Rate

5.5 Run Time and GUI

Run speeds of tNavigator are much higher than that of Eclipse. RFD claims in most of the cases, it is capable of running the models 10-20 times faster than other simulators on modern workstations. This is because tNavigator is parallel simulator. Large models can be run on clusters by applying a hybrid approach that combines MPI and system thread technologies for distributed and shared memory respectively. This approach eliminates the typical bottlenecks in parallel computations and exhibits great scalability on large reservoir models.

6. Conclusions

- With the current water injection network overall recovery in base case is about 69 MSm^3 of about 160 MSm^3 of original oil in place that amounts to 43% recovery.

- If ASP flooding is followed, in low injection case, recovery is about 82 MSm^3. That is about 51.3%.

- When the chemical injections are increased, in medium injection case where 1.5 times the low injection case, recovery is 85 MSm^3 that is about 53.1%.

- In high chemical injection case, where injection rate are twice that of low injection case, total production is 86 MSm^3 that is equivalent to 53.8%.

- The reason for very little improvement upon increasing the chemical injection is, this network is not designed for the chemical injection. If a well-designed pattern flooding is followed, this field can be a good candidate for ASP flooding.

- tNavigator results are comparable with eclipse results in most of the cases; however, there is always a little difference in gas phase calculations.

- tNavigator is 3 to 4 times faster than the eclipse in run times. tNavigator has a very good user interface to view the results and to communicate with the tool.

7. References

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