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# Modeling of Miscible WAG Injection Using Real Geological Field Data

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## ABSTRACT

Maximizing oil recovery is the challenge for the oil industry in the North Sea and world wide. Norwegian national company Statoil set the goal to reach oil recovery of 60% for their fields on NCS. To achieve this target a number of enhanced oil recovery technologies are being applied, including water alternating gas injection.

The purpose of this study is to investigate the possibility of effective improvement of oil recovery with WAG injection for the field, which has high permeability zone in the upper part of the reservoir and has no dip. A dummy Eclipse 100 reservoir model, based on the geological model of Gullfaks segment K1/K2, was used. The original Gullfaks fluid was substituted with the fluid from SPE5 Comparative study.

Miscibility of injection gas and reservoir oil was studied using the slim tube simulations with numerical simulator SENSOR by Coats Engineering. The results of simulations were compared with those obtained with equation of state based multicell procedure. The equation of state based calculations were conducted with PhazeComp, phase behavior modeling software by Zick Technologies.

Numerical simulations of coarse grid segment, extracted from field scale model, were run to obtain the match between black oil model with Todd-Longstaff formulation of miscible displacement, and compositional model, by changing mixing parameter value. Grid refinement for compositional model was used to obtain more accurate results. The models were verified for depletion and water injection cases, and then compared for WAG injection cases with different cycles and injection rates. The simulations were run with Eclipse 100 and Eclipse 300.

This segment model was used to study the effect of different completion schemes for this particular reservoir to find the most effective one. Changing completion scenario was proposed. Also the influence of different WAG design parameters was studied, including half-cycle length, number of cycles, injection rate. Simulations water alternating gas injection was also tested. The results were used for field scale modeling.

For the field development modeling, 19 cases were constructed to study different WAG scenarios, including early time, late time and lifetime WAG injection. Different cycle lengths were studied, also including SWAG. Changing completion scenario was tested. All the cases were compared with water injection scenario. The influence of residual oil saturation on results was studied.

Overall it was found that though water flooding is giving good results with high recovery, it is possible to improve recovery by up to 6.2 % (1.67 million Sm<sup>3</sup> of oil) by using lifetime WAG injection, with produced oil per gas injected ratio in the range of 585 Sm<sup>3</sup>/MSm<sup>3</sup>. Late time injection can also be used, giving the recovery increase by 3.4 %. (1.125 million Sm<sup>3</sup> of oil), with higher oil per gas ratio of 780 Sm<sup>3</sup>/Sm<sup>3</sup>. There is also high back production of injected gas (more than 80%).



# LIST OF CONTENTS

INTRODUCTION.....	6
1. THEORY REVIEW .....	7
1.1 Water alternating gas injection .....	7
1.1.1 History.....	7
1.1.2 Mechanism.....	8
1.2 Miscibility.....	9
1.2.1 First-contact miscibility .....	9
1.2.2 Developed miscibility .....	10
1.3 Evaluation of miscibility.....	10
1.3.1 MMP and MME.....	11
1.3.2 Slim tube experiment.....	11
1.3.3 Multicontact calculations with EOS .....	12
1.4 Todd-Longstaff model.....	12
2. RESERVOIR DESCRIPTION.....	15
2.1 Geological model of reservoir.....	15
2.2 Reservoir fluid.....	16
3. MINIMUM MISCIBILITY PRESSURE CALCULATIONS.....	17
3.1 Calculations with multicell EOS based method.....	17
3.2 SENSOR simulation of slim tube experiment .....	17
4. SEGMENT MODELING.....	18
4.1 Selection of Todd-Longstaff mixing parameter.....	18
4.1.1 Coarse grid and fine grid model.....	18
4.1.2 Black oil model and compositional model.....	19
4.1.3 Depletion.....	19
4.1.4 Water injection.....	20
4.1.5 Water alternating gas injection. Selection of mixing parameter.....	20
4.2 Modeling of different design decisions for WAG.....	23
4.2.1 Completion scheme.....	23
4.2.2 WAG parameters test.....	25
5. FIELD PRODUCTION MODELING .....	27
5.1 Water flooding modeling.....	27
5.2 Water alternating gas modeling .....	28
5.2.1 Early time WAG injection .....	28
5.2.2 Late time WAG injection.....	29
5.2.3 Life time WAG injection .....	30
5.2.4 Changing completion scheme lifetime WAG.....	31
5.2.5 Residual oil saturation after miscible flooding sensitivity.....	32
5.3 Discussion of results of field scale modeling.....	32
6. CONCLUSIONS .....	35
7. REFERENCES .....	37
8. NOMENCLATURE.....	39
APPENDIX A. Tables.....	40
APPENDIX B. Figures.....	47





# INTRODUCTION

Facing the challenging problem of maximizing oil recovery, oil industry has been working on development and maturing of EOR technologies. One of the most successful and used technologies in the North Sea is water alternating gas injection (WAG).

This report is devoted to evaluation of possibility to implement the water alternating gas injection on the field with no dip and high permeability zone in the upper part of the reservoir. For this purpose dummy reservoir model was constructed, based on the model of Gullfaks K1/K2 field. The original fluid was substituted with the fluid from SPE5 Comparative study. This was done to obtain new field for analysis, but with realistic geology. The author is aware of economical aspects of the field development, but those will not be studied here. Other works were studied for the theory review and for purpose of widening knowledge about the topic (References 1-17).

The problems addressed are presented below:

1. Evaluation of miscibility of injection gas and reservoir oil from SPE5 Comparative study with slim tube simulations and equation of state based multicell calculations. The simulation of slim tube experiment is conducted with numerical simulator SENSOR by Coats Engineering. For equation of state based multicell procedure PhazeComp is used, the software for modeling of phase behavior by Zick Technologies. Minimum miscibility pressure is determined and compared for both approaches. The results are used for the simulations of miscible displacement.
2. The black oil model with Todd-Longstaff formulation of miscible displacement and compositional model are compared and matched. For this purpose the segment is extracted from the field scale model. The grid refinement is applied for compositional model to reduce numerical error. The black oil model of the segment with the original size of grid blocks (coarse grid blocks) was verified with the compositional model for the depletion case and water injection case. To match the performance of the models for the WAG case, mixing parameter of Todd-Longstaff is varied. The match is verified for different half-cycle lengths and injection rates. The simulations are run with Eclipse 100 and Eclipse 300.
3. The segment model is used to determine the best completion scheme for this field. The best scheme is to be used for field scale modeling. Influence of different WAG design parameters, such as half-cycle length (including simultaneous water and gas injection -SWAG), number of cycles and injection rates, is studied.
4. Field scale modeling of WAG injection is conducted using Eclipse 100 reservoir simulator. The results obtained in previous sections are applied. A number of cases for WAG injection, including early time, late time, lifetime WAG injection are studied. The models are run for different half-cycle lengths, including SWAG. The results are compared with the water flooding case.

# 1. THEORY REVIEW

## 1.1 Water alternating gas injection

### 1.1.1 History

Water alternating gas injection is the enhanced oil recovery technology referred to as the method of alternating gas slugs injection followed by water injection, repeated in several cycles. This technology has been used with success worldwide since 1957, when it was first applied in Canada. (Christensen et al. 1998). Since that time WAG technology was proved effective, and was mostly used in Canada, the North Sea and the countries of former USSR.

In 1998 Christensen et al. published their survey of the field implementations of the technology worldwide. Totally 59 applications of WAG injection were studied, including miscible and immiscible WAG and hydrocarbon and non-hydrocarbon gases. For most of the fields the technology was used as a tertiary method, except for the North Sea new project, where WAG was initiated at the early stages. Only 6 of the projects were implemented offshore, all of them in the North Sea. WAG ratio used in the fields was most of the time 1, with values 3 and 4 for some cases; the gas slugs varied in the range of 0.1 to 3 pore volumes. The majority of reviewed projects resulted in significant incremental oil recovery of 5 to 10%.

According to Kleppe et al. paper published in 2006, WAG is the most commonly used EOR technology in the North Sea, and is considered mature. This paper reports about 9 water-alternating-gas projects, with six being immiscible WAG. There have been field scale applications of WAG ( Brage, Staffjord), and several pilot projects at Gullfaks, Ekofisk, Thistle and Oseberg Ost. Magnus project is reported to be field scale miscible WAG, Snorre A and Brae South are miscible WAG-pilots. In the reviewed fields WAG was mainly implemented as downdip injection. In the North Sea, water flooding gave good results, so the main objective of the WAG application there was to drain attic oil. For downdip injection, gravity difference helps to displace attic oil by gas and bottom oil by water. (Kleppe et al. 2006)

WAG injection in the North Sea is not the same as for onshore projects, mainly because the common five-spot pattern with close wells is difficult to implement as the drilling is very expensive offshore. Wells are located due to geological considerations and seldom any fixed pattern is used. Side-tracks have been reported to be used to produce the oil-by-gas sweep without excessive gas and water production. (Kleppe et al. 2006) (Christensen et al. 1998)

In the North Sea WAG projects were initiated using HC gas because of its availability. CO<sub>2</sub> injection has been proven as a successful technology worldwide, with less minimum miscibility pressures than HC gases. Statoil has introduced the new well pattern for CO<sub>2</sub> miscible WAG at Gullfaks, and showed that field production can be extended up to 2030, with WAG using HC gas yields production only until 2020. The main problem for application of CO<sub>2</sub> in the North Sea is its availability. (Kleppe et al. 2006)

Though there are some technological restrictions, summarized by Kleppe et al:

1. Hydrate formation in previously water flooded and cooled reservoirs
2. Availability of CO<sub>2</sub>, and corrosion issues
3. Economical analysis of gas injection or gas-to-market option.
4. Pressure, temperature and compositions of solvent and reservoir fluid for miscible WAG
5. Well spacing, WAG ratio, reservoir thickness, permeability anisotropy, WAG cycle

### 1.1.2 Mechanism

Overall recovery factor is the product of areal and vertical sweep efficiency and microscopic displacement efficiency. WAG technology allows improving oil recovery by increasing sweep efficiency and gas injection also leads to better microscopic drainage. Injection of gas after water allows draining of attic and bypassed oil, and the microscopic displacement of oil by gas can result in residual oil saturation significantly lower than for the water – oil displacement.

The flow zones during WAG process in a horizontal homogeneous reservoir are represented below on the figure 1.1.

As can be seen, due to gravity difference gas tends to make its way along the cellar of reservoir, resulting in not favorable sweep and early break-through, but the residual oil saturation in the displaced volume is very low. Yet again due to gravity water displaces oil in the lower part of the reservoir. Microscopic recovery for water-oil displacement is not as good as for gas-oil case, and residual oil saturation can reach up to 30%. In the mixing zone three phase flow occurs. To predict oil recovery from the mixed flow zone, three phase relative permeability study is required, but overall prediction is that the residual oil saturation will be lower than for the pure water flood case. The extension of the mixed zone depends on the length of the cycles and the viscous forces to gravity forces ratio. There have been recommendations in the industry to use shorter cycles and even simultaneous water and gas injection to increase the size of the mixing zone (Kleppe et al. 2006). However, it can be difficult to implement such an injection scheme due to injectivity problems around the well. If the size of the mixed zone is small relative to the distance between the injector and producer, this zone soon develops a steady state condition.

WAG technology can have better effect in the dipping reservoir, where updip or downdip injection can be implemented. As reported by Kleppe et al., all of the WAG injection projects in the North Sea were with downdip injection.

Injection of gas and water in the deeper part of the dipping reservoir leads to more intensive segregation effects. In this case WAG has even higher efficiency, and obviously better effect than pure water or gas flooding due to better sweep efficiency and increased macroscopic recovery.

Microscopic displacement efficiency of oil by gas is different for miscible and immiscible conditions, with recovery improvement in miscible displacement case as there is zero capillary pressure between solvent and oil and no relative permeability effects.

Microscopic recovery can also be improved by modifications of water for injection (water-oil displacement).

## **1.2 Miscibility**

Miscibility is the property of fluids to mix (form a single phase) at any proportions. It can have a great influence on the success of gas injection and WAG process. The microscopic recovery is highly dependent on the mixing of the injection fluid and reservoir fluid, which can be not mixing (immiscible displacement), partly mixing and mixing (miscible displacement). The drainage mechanism is more favorable during miscible displacement, as there is no influence of relative permeabilities of mixing fluids. Therefore, it results in very high microscopic recoveries. It's been good practice during WAG projects to repressurize the reservoir until the miscible conditions. However, it can be challenging to maintain required conditions for miscibility and less cost effective.

A ternary composition diagram can be used to determine whether two mixtures are first-contact miscible or if they can develop miscibility at several contacts. Typical ternary composition diagram can be observed on the figure 1.2 (Whitson & Brule Phase Behavior SPE monograph 2000).

The critical composition is shown as the critical point C. There is also phase envelope enclosing all the compositions that will split into two phases when brought to this pressure and temperature. The upper curve of the envelope is the dewpoint curve, the lower – bubblepoint curve, two curves join at the critical composition, C. Tie-lines are the straight lines that connect an equilibrium-vapor composition with referred equilibrium-liquid composition. Any mixture that falls on the tie-line will split into two phases with equilibrium vapor and liquid compositions determined by the end-points of this specific tie-line. A limiting tie-line is drawn through critical composition.

Pseudoternary diagrams are also used for multicomponent fluids, where several components are grouped together and represented at each apex on the ternary diagram. This method is used despite the inherent limitation that multicomponent phase behavior cannot be represented uniquely with a ternary diagram. Ternary representation of multicomponent system is valid only if the relative amounts of all components defining each pseudocomponent remain constant, what cannot be achieved for oil systems. (Whitson & Brule Phase Behavior SPE monograph 2000)

### **1.2.1 First-contact miscibility**

Two fluids are first-contact miscible if the line connecting the compositions of these two fluids is not crossing the region within phase envelope on the ternary composition diagram. As an example, on the figure 1.2 G1 and G2, O1 and O2, G2 and O2 are first-contact miscible fluids.

### 1.2.2 Developed miscibility

The critical tie-line on the ternary composition diagram determines whether two fluids can develop miscibility by multiple-contact process. Two fluids can develop multiple-contact miscibility if their compositions lie on the different sides of the critical tie-line. As for the figure 3, G1/O2 and O1/G2 can develop miscibility.

C1 and O2 fluids can develop miscibility through vaporizing-gas drive mechanism. Intermediate and heavy components from the oil O2 vaporize into the gas phase, making the original lean gas C1 richer, which later on contact oil again and becomes even richer until it get to the critical composition C, which is miscible with oil O2. The process is shown on the figure 1.3. The gas and oil are mixed in the proportions that the overall composition of the mixture falls into the two phase region. The equilibrium gas G2 is now enriched with intermediate and heavy components, and then again is mixed with the original oil O2 at proportions to form two phase conditions. The more enriched gas G3 is obtained. The process goes on until critical composition C is reached, when miscibility is developed. (Whitson & Brule Phase Behavior SPE monograph 2000)

Fluids G2 and O1 can develop miscibility by what is called enriched-gas miscible drive process (condensing gas process). The intermediate component nC4 in the original gas G1 is condensed into oil O2, which becomes richer after several contacts with gas until it gets to critical composition C. The path is in analogy with vaporizing-gas drive described earlier and is presented on the figure 1.4.

But as proved by Zick in his paper “A Combined Condensing/Vaporizing Mechanism In The Displacement Of Oil By Enriched Gases”, pseudoternary representation of enriched-gas drive is not the proper explanation for the actual recovery mechanism. He proposed another mechanism, which is combination of two processes:

- vaporization of the middle components from the original oil into the gas at a trailing front
- enrichment of oil by the leading front with light intermediate components found in original gas and middle intermediate components, vaporized from the oil.

A sharp transition near miscible zone separates condensing and vaporizing zones.

The mechanism is called condensing/vaporizing, and the following regions are pointed out:

1. Original oil zone
2. A leading two – phase from where condensation of light and middle intermediate components from the gas phase occurs.
3. Transition zone, where very effective condensation of intermediate and heavy components and vaporization of intermediate and heavy components occurs on the front and trailing side respectively.
4. Trailing from where happens vaporization of middle components from the residual oil
5. Stripped residual oil, mainly heavy and non-volatile, which is in equilibrium with injection gas.

### 1.3 Evaluation of miscibility

As has been discussed in the previous chapters, miscibility is very important for microscopic displacement efficiency of oil by gas. Therefore, proper evaluation of miscibility of injected gas and reservoir oil is required for proper design of WAG project.

### **1.3.1 MMP and MME**

Minimum miscibility pressure (MMP) is the minimum pressure for a specific temperature at which miscibility can occur independent of overall composition. For the miscible WAG project the reservoir pressure must be maintained at minimum miscibility pressure or higher. The MMP is reported to be a function of temperature and composition.

Minimum miscibility enrichment (MME) is referred to as the minimum enrichment of injection gas required for it to develop miscibility with the given reservoir fluid at the specific pressure and temperature. The injection gas must be enriched to MME or higher to develop miscibility with reservoir fluid during WAG project. (Whitson & Brule Phase Behavior SPE monograph 2000)

Several methods for determination of MMP and MME have been proposed: slim tube experiment, multicontact calculations with EOS, correlations.

### **1.3.2 Slim tube experiment**

Slim tube experiment is the displacement experiment based on calculation of recovery. A slim-tube apparatus is presented on the figure 1.5.

Most of the slim tubes consist of 0.25-in.-outer diameter coiled tubing with the length of 25-75 ft., packed with uniform sand and put in the constant temperature container.

Slim tube results are interpreted by plotting oil recovery vs. pressure for 1.2 pore volume injected. The displacement experiment is run at different pressures. Miscible displacement basically results in very high recoveries hitting 100%, as there is one phase and zero capillary pressure. For immiscible case, oil recovery is lower due to relative permeability and capillary pressure effects.

With increasing pressure at which the experiment is conducted, the recovery factor increases until the recovery factor vs. pressure curve flattens, showing miscible displacement performance. Depending on the type of displacement process, temperature, injection gas and other factors, the transition from immiscible to miscible conditions can be gradual or abrupt. It is arbitrary what point to choose as the point of the start of miscible conditions. Typical recovery factor vs. pressure curve for slim tube experiment is presented on the figure 1.6. (Whitson & Brule Phase Behavior SPE monograph 2000)

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### **1.3.3 Multicontact calculations with EOS**

There are several methods for calculation of MMP with an equation of state. Most of them are forward contact or backward contact procedures which fairly good describe vaporizing gas miscible drive, but are not recommended for condensing/vaporizing drive modeling.

Metcalf et al. proposes a calculation approach based on multicell vaporization model: fluid mixing goes along a series of connected cells, which simulate the development of miscibility by multiple contact process. The schematic of the calculation approach is presented on the figure 1.8.

Initially all the cells are filled with oil, then the first cells is mixed with the certain volume of gas, the mixture is brought to equilibrium and the gas is then taken to the second cell to contact with the initial oil again. The process continues in the approximately 50 cells. After this initial injection gas is contacted with the cell number one again, and the procedure goes on. This allows simulating the process in time. The results are plotted on the ternary diagram to apply the critical tie-line approach for establishing the condition the miscibility. The process also allows modeling driving of enriched gas slug by leaner gas by using different injection gas composition used at different time of experiment. Generally 3 methods of multicell calculations were proposed by Mercalfe et al. which are intended for modeling of normal vaporizing drive and condensing/vaporizing drive. For the first method all equilibrium gas is passed from cell to cell, another two pass whether just enough oil and gas to the next cell to ensure that remaining mixture fills in the current cell or volumes of passed oil and gas are determined according to mobility ratio.

This procedure if interpreted correctly can give close results to the slim tube experiment, and can be considered as the best generalized scheme for determining conditions required for miscibility development. (Whitson & Brule Phase Behavior SPE monograph 2000)

### **1.4 Todd-Longstaff model**

Todd and Longstaff in 1972 proposed a method for modifying the three phase simulator so that it can be used for modeling of miscible flooding (Todd & Longstaff. The development, testing and application of a numerical simulator for predicting miscible flood performance. 1972). The model described in this paper implies that the characteristics of the miscible displacement can be calculated without reproducing the fine structure of the displacement front.

There were 2 models proposed – two component miscible flow model on the base of three-component simulator, and four – component model for slug and continuous gas injection., where 3 component miscible flow occurs (gas, slug of solvent, oil). In the model gas and oil are considered as miscible components of non-wetting hydrocarbon phase, what means that there is no capillary pressure between oil and gas. Based on that relative permeability, viscosity and density description is proposed.

For relative permeability it is considered that for each of miscible components (gas and oil) a fraction of the non-wetting phase relative permeability is equal to its volume fraction in the porous medium. Relative permeabilities are determined as follows:

$$\begin{aligned}
 K_{ro} &= \frac{S_o}{S_n} * K_m \\
 K_{rg} &= \frac{S_g}{S_n} * K_m
 \end{aligned}
 \dots\dots\dots(1.1)$$

where  $S_n = S_o + S_g$  - non-wetting phase saturation, and  $K_m$  is the imbibition relative permeability of the non-wetting phase.

The viscosity and density of each component is represented with a single value that reflects the effective fluid property averaged for the entire grid block. The rate of dispersion of gas in oil determines the size of dispersed zone. If the dispersion rate is high enough, the dispersed zone will be larger than the grid block, and oil and gas can be considered completely mixing within the grid block. This means that viscosity and density of the components are the same. If on the other hand dispersion rate is low enough that the size of dispersed zone is negligibly low in comparison to grid block dimensions, then the oil and gas will have the viscosity and density of pure components. The mixing parameter  $\omega$  was proposed to correspond this dispersion rate and as follows the size of dispersed zone.

At this case the effective viscosity for each component is calculated as follows:

$$\begin{aligned}
 \mu_{oe} &= \mu_o^{1-\omega} * \mu_m^\omega \\
 \mu_{ge} &= \mu_g^{1-\omega} * \mu_m^\omega
 \end{aligned}
 \dots\dots\dots(1.2)$$

$$\mu_m = \frac{\mu_o * \mu_g}{\left( \frac{S_g}{S_n} * \mu_o^{0.25} + \frac{S_o}{S_n} * \mu_g^{0.25} \right)^4}$$

Where  $\mu_m$  is the viscosity of the mixture. The value of mixing parameter equal to 0 means negligible dispersion rate, when value of 1 means complete mixing of oil and gas within the grid block.

The effective densities can be calculated with the equations below:



$$\rho_{oe} = \rho_o * \left( \frac{S_o}{S_n} \right)_{oe} + \rho_g * \left[ 1 - \left( \frac{S_o}{S_n} \right)_{oe} \right]$$

$$\rho_{ge} = \rho_o * \left( \frac{S_o}{S_n} \right)_{ge} + \rho_g * \left[ 1 - \left( \frac{S_o}{S_n} \right)_{ge} \right] \dots\dots\dots(1.3)$$

In these equations effective fractional saturations are calculated as follows:

$$\left( \frac{S_o}{S_n} \right)_{oe} = \frac{M^{1/4} - (\mu_o / \mu_{oe})^{1/4}}{M^{1/4} - 1} \dots\dots\dots(1.4)$$

$$\left( \frac{S_o}{S_n} \right)_{ge} = \frac{M^{1/4} - (\mu_o / \mu_{ge})^{1/4}}{M^{1/4} - 1}$$

Where  $M$  is mobility ratio.

Another option of calculation of densities where mixture density is used is presented below:

$$\rho_{oe} = (1 - \omega) * \rho_o + \omega * \rho_m$$

$$\rho_{ge} = (1 - \omega) * \rho_g + \omega * \rho_m \dots\dots\dots(1.5)$$

Where the mixture density is calculated as follows:

$$\rho_m = \rho_o * \frac{S_o}{S_n} + \rho_g * \frac{S_g}{S_n} \dots\dots\dots(1.6)$$

For the four-component model one extra equation as added to relative permeability, viscosity and density calculations, to handle 3 components in non-wetting phase – gas (which is not miscible with oil), solvent, oil.

The normal input to the simulator has water, oil and gas relative permeabilities, viscosities, densities, capillary pressures for water/oil and oil/gas. For the miscible calculations this input is used to do calculations described above.

## 2. RESERVOIR DESCRIPTION

Geological model of the reservoir used in this study is dummy and is based on the original Eclipse 100 model of Gullfaks segment K1/K2. Several changes were made in the model, including the change of the fluid (it is taken from SPE5 comparative study), deleting the fault between segments K1 and K2, and vertical permeability changes made in some layers. The model is constructed to study a new case with reservoir model having real geological data.

### 2.1 Geological model of reservoir

The top of the reservoir is located at the depth of 1870 m, and the reservoir thickness is in the range of 200 m. The reservoir is flat, with no dip. The original reservoir rock of Statfjord formation is sand with high permeability (1-4 Darcy) and the rock is quite homogeneous. The reservoir is water wet. The main reservoir parameters are summed up in the table 2.1.

**Table 2.1 Reservoir parameters**

<b>Top structure</b>	1870	m
<b>Initial temperature</b>	160	<sup>0</sup> F
<b>Initial pressure</b>	320	bar
<b>Bubble-point pressure</b>	159	bar
<b>In-situ gas-oil ratio</b>	102.02	Sm <sup>3</sup> /Sm <sup>3</sup>
<b>Formation volume factor at BP</b>	1.301	Rm <sup>3</sup> /Sm <sup>3</sup>
<b>at 320 bar</b>	1.254	Rm <sup>3</sup> /Sm <sup>3</sup>
<b>Oil density</b>	617.2	kg/m <sup>3</sup>
<b>Oil viscosity</b>	0.260-0.203	cP
<b>Permeability</b>	0.4 - 4	D
<b>Porosity</b>	20-35	%
<b>Rock compressibility at 330 bar</b>	9e-005	1/bar
<b>STOOIP</b>	19.7	MSm <sup>3</sup>

The horizontal permeability distribution of the reservoir can be seen on the figure 2.1.

The reservoir has high permeability layer at the top, and low permeability layer at the bottom (the bottom layers are water filled)

The vertical permeability of the reservoir is modified by MULTZ keyword and is 10 times less than the horizontal permeability for most of the layers, but the layers 13 and 10 have MULTZ=0.05, the layer 12 has MULTZ=0.005, the layer 15 is not permeable in vertical direction.

There are several faults in the reservoir. All the faults are not permeable except for the one which has 10% of the normal permeability and goes from south to north. The figure 2.2 demonstrates the distribution of the faults. As can be seen from the figure the eastern part of reservoir is cut off from the other parts.

The distribution of the pore volume shows that the pore volume has the highest values in the southern part of the reservoir. The pore volume distribution is presented on the figure 2.3.

The reservoir is originally saturated with oil and water, the water is located in the bottom part of the reservoir. The reservoir has no aquifer support and no gas cap. The initial fluids saturation distribution is presented on the figure 2.4.

The relative permeability data was taken from the original model of K1/K2 segment and is presented on the figure 2.5. For WAG cases, relative permeability tables for 3 phase cases must be provided. All the data was originally present in the K1/K2 model, and was used for this study.

The critical saturations for water, oil and gas for different cases are entered in the PROPS section of the DATA file with the help of include file. Residual oil saturation for oil-gas case is 10%, critical gas saturation is 3%; for water-oil case residual oil saturation is in the range of 15-20%. The distributions of residual oil saturation values for oil-water case and critical water saturation are presented on the figures 2.6-2.7.

## 2.2 Reservoir fluid

The reservoir fluid in this work is taken from the SPE5 Comparative study (Killough & Kossack. Fifth Comparative Solution Project: Evaluation of Miscible Flood Simulators, 1987). The in situ fluid is undersaturated oil, with gas-oil ratio 102.02 Sm<sup>3</sup>/Sm<sup>3</sup>. The fluid has the same gas-oil ratio in the entire reservoir. At the initial pressure of 320 bar the formation volume factor is 1.254 Rm<sup>3</sup>/Sm<sup>3</sup>. For the compositional runs Peng-Robinson cubic equation of state is used, which is also referred to SPE5 Comparative study. The composition of oil and composition of injection gas are presented in table 2.2. The separation process used is one stage separation at standard conditions. The black oil table used in this work is taken from the Eclipse files with comparative studies, provided by Schlumberger.

**Table 2.2 Composition of oil and injection gas.**

<b>Component</b>	<b>Mole fr (Reservoir oil)</b>	<b>Mole fr (Injection gas)</b>
<b>C1</b>	0.5	0.77
<b>C3</b>	0.03	0.20
<b>C6</b>	0.07	0.03
<b>C10</b>	0.2	0
<b>C15</b>	0.15	0
<b>C20</b>	0.05	0

### **3. MINIMUM MISCIBILITY PRESSURE CALCULATIONS**

#### **3.1 Calculations with multicell EOS based method**

This calculation was performed with PhazeComp – software developed by Zich Technologies. The method of multicell EOS based calculation of minimum miscibility pressure described in Chapter 1.3 is implemented in PhazeComp. The input for calculations is cubic equation of state, oil and enriched gas compositions from SPE5 Comparative study, and temperature of 160 F<sup>0</sup>.

For this method the results show condensing/vaporizing drive for developed miscibility of reservoir fluid and enriched injection gas.

The MMP – 2842 psia, 195.9 bar

#### **3.2 SENSOR simulation of slim tube experiment**

Displacement of gas by oil in a slim tube was simulated by using finite difference compositional simulator SENSOR (Coats Engineering product). The slim tube length is 1000 ft, width – 561.5 ft, height – 100 ft. The porosity is 10%. The model is designed in the way so that when gas is injected the pressure drop along the tube is about 5-10 psia, so the displacement and multicontact miscibility occurs at the specific constant pressure in the tube. Composition of gas and oil, as well as equation of state are the same as for multicell EOS based calculations and are taken from SPE5 Comparative study. The temperature of the system is 160 F<sup>0</sup>.

The injection of 1.2 pore volume of enriched gas (composition given in Table 2.2) is performed for a range of pressures. The results of simulations are plotted against  $N^{-0.5}$  where N is number of cells, and are grouped for each pressure step. This allows determination of the recovery factors with no numerical dispersion having influence on the results. The figure 3.1 shows the plot with the results of the simulations. The values of recovery factors for infinite number of cells are obtained by graphical interpolation of the curves, corresponding to each pressure step.

From the figure 3.1 the recovery factors were obtained for infinite number of cells. Pressure vs. recovery factor plot can be observed on the figure 3.2. The minimum miscibility pressure is in the range from 2800 to 2850 psia for the slim tube simulation, and is close to the value obtained with multicell equation of state based calculations – 2842 psia. This is in good consistency with the theory of EOS based multicell calculations of the MMP, as the routine is expected to track the multicontact process close to the real displacement situation. For this particular case, the EOS based calculations and the slim tube simulations showed almost the same results. For the following studies the minimum miscibility pressure of 195.9 bar is used.

## 4. SEGMENT MODELING

The segment is extracted from the entire reservoir model. The purpose for this is to do verification of black oil model with Todd-Longstaff formulation of miscible displacement, and compositional model. The segment model is modified to have more grids for the compositional case. Another part of this study is to use this segment for determination of the best completion strategy and running sensitivity on the best design of WAG – length of cycles, quantity of cycles and injection rates. For this purposes Eclipse 100 and Eclipse 300 by Schlumberger were used. Post-processing software S3Graf-3D by Sciencesoft was used for analysis of the results. All the recovery factor percentages refer to original oil in place.

### 4.1 Selection of Todd-Longstaff mixing parameter

In this part the coarse grid black oil model and fine grid compositional models performances are compared, and the mixing parameter of Todd-Longstaff is selected to match these models for the case of water alternating gas injection. The task is to select the segment within the field, make grid refinement of it, then run black oil coarse grid model and compositional fine grid model for depletion case, water injection case to verify their consistency and to avoid uncertainties in analysis of WAG runs. Then WAG runs are made on both models for the purpose of selection of the mixing parameter for black oil model, which will match performance of black oil model with compositional model. When this is done, rate sensitivity and injection cycles parameters sensitivities are performed to check the match.

#### 4.1.1 Coarse grid and fine grid model

The coarse grid segment model is the model with the same size of grid blocks as in the field scale model. The model is extracted from the K2 segment, with vertical faults being deleted. All other geological parameters remain the same. The fine grid segment model is exactly the same model with the only difference that there are 2 times more grid blocks used in it. To extract the segment all the grid blocks around it were made inactive in the field scale model, and for generation of fine grid model the local grid refinement option of Eclipse was used. The parameters of the models are presented in the table 4.1.

The segment models can be observed on the figures 4.1-4.2.

As known from the Todd-Longstaff model, described in the Chapter 1.4 of this work, the mixing parameter  $\omega$  corresponds to the dispersion rate and size of dispersed zone with respect to the size of grid blocks. Application of fine grid model allows benefit from less numerical dispersion of the results. Further refinement was not used due to computational limits. For the support coarse grid compositional model was sometimes used to compare the results.

### 4.1.2 Black oil model and compositional model

As discussed before in Chapter 2.2, the fluid model is taken from the SPE5 Comparative study. The compositional model and black oil model are both taken from the SPE5 files provided by Schlumberger with Eclipse package. Units conversion from field system to metric system was done to keep consistency with other parts of model, where metric system is used. The black oil table from the SPE5 model of Eclipse is presented in the table 4.2.

The original oil in place of the model is 5.46 MSm<sup>3</sup>.

For the compositional model equation of state is verified to be in consistence with SPE5 paper. For the runs with WAG injection, Todd-Longstaff mixing parameter was varied to match the black oil model to compositional model. The miscibility pressure was taken accordingly to studies described in Chapter 3.

### 4.1.3 Depletion

For the depletion case one production well was placed in the center of the model. The well is set for a rate control and on a constant production rate of 1000 Sm<sup>3</sup>/d. The bottomhole pressure limit is set to 50 bar. This scenario was run on the black oil coarse grid model, on the compositional fine grid and coarse grid models. The results showed significant difference in the behavior of black oil model and compositional models. The black oil model shows higher pressure drop than compositional models while undersaturated conditions are maintained. After the bubble-point is reached, the pressure difference is still observed on the late stage of the production. The explanation for the first problem is poor black oil tables for undersaturated conditions of oil. The compressibility of oil in the black oil model is much lower than it should be. During verification of the model it was found that in the SPE5 Comparative study the differential vaporization test presented in Table 7 of the paper (Killough, Kossack 1987) there is difference in oil relative volume between the paper and the data in the PVT table.

The original PVT table proposed by Schlumberger was changed for undersaturated oil with gas-oil ratio 102.02 Sm<sup>3</sup>/Sm<sup>3</sup>. The changes can be found in the table 4.3.

The results of simulations with the modified table are presented on the figures 4.3 – 4.5. The results are good for the undersaturated part and for saturated part where free gas comes out of solution. It is noticeable that for the coarse grid model match is worse than for the fine grid compositional model.

The generation of new PVT tables with PVTi was not possible to do as the experimental data from SPE5 was difficult to match.

The match between the modified black oil model and compositional fine grid model is good for all parameters. As the pressure will be maintained for the water injection, WAG injection and field scale simulations, it is considered that this modified model can be used for these cases.

#### 4.1.4 Water injection

Next the water injection scenario is tested. The injection well and production well are placed in the model. The production well is put on the rate control at constant production rate of 2000 Sm<sup>3</sup>/d, with minimum bottomhole pressure of 300 bar. The water injection rate is set to 2400 Sm<sup>3</sup>/d to maintain pressure in the reservoir. The results of simulations are presented on the figures 4.6 – 4.8.

It can be seen that there is acceptable match between the models. Black oil coarse grid model with modified PVT tables has better match with fine grid compositional model than with coarse grid compositional model. The original black oil model shows big difference in pressure with other models. This leads to faster occurring drop in production in the beginning. The modified black oil model gives better results, though it has some differences as well. It is worth mentioning that the pressure at the late stage is the same for both black oil models. The water production rate is also the same for these models.

Overall the match is good, and this is the best match it was possible to obtain. As expected the modified black oil model shows good results when pressure is maintained. Fine grid model shows sharper water front than coarse grid model for compositional runs. Keeping all this in mind, it is expected that the differences for WAG case will be due to miscibility representation by Todd-Longstaff model.

#### 4.1.5 Water alternating gas injection. Selection of mixing parameter.

For water alternating gas case again one production and one injection well are introduced. The production well is put on the constant production rate of 1000 Sm<sup>3</sup>/d, with minimum bottomhole pressure of 300 bar. The water and gas injection rates are 1200 Sm<sup>3</sup>/d and 380000 Sm<sup>3</sup>/d respectively. The water is injected for one year after start of production, and then two slugs of gas with WAG half-cycle of 12 months are injected. After that water is injected until the end of production. The injection scheme can be seen on the figure 4.9.

The minimum miscibility pressure was set to 195.9 bar, as it was calculated in Chapter 3 of this study. For the black oil model mixing parameter was varied from 0 to 1 to track the influence of different values. Only modified black oil model was used. The results of simulations are presented on the figures 4.10 – 4.14.

The observations are summed up below.

##### **Oil production rates**

Both compositional models show good consistency. For the black oil model, oil production rate for all the cases with mixing parameter lower than 1 is close, but these cases are not matching good with compositional model. Only the case with mixing parameter equal to 1 shows reasonable match with the compositional models, though black oil model underpredicts the oil rate. But at the same time the curves' shape is very close.

### **Pressure**

There is big difference between the models with mixing parameter lower than 1 and other models. The model with mixing parameter equal to 1 gives better match with compositional models.

### **Gas-oil ratio**

Gas-oil ratio shows big differences between compositional models and cases with mixing parameter lower than 1. For mixing parameter equal to 1 match is better and the shape of the curves is close.

### **Water production rate**

There are differences among the models with mixing parameter lower than 1. The model with mixing parameter equal to 1 shows good match with compositional models.

### **Ultimate recovery**

Differences in oil production rates resulted in big ultimate recovery differences for the cases with mixing parameter lower than 1. For the case with mixing parameter equal to 1 match with compositional models is good.

For all the cases with mixing parameter lower than 1 curves' behavior indicates that there is some free gas in the model which is not mixed with oil. This gas breaks through as a slug and results in high GOR increase (the pick on the GOR curve). As the gas is not breaking through the pressure is not dropping and this results in the difference in pressure with compositional model. In the case with mixing parameter equal to 1 injected gas and oil are treated in the way that there is high dispersion rate, and gas and oil form one phase fast. This is reasonable as the minimum miscibility pressure is 100 bar lower than the reservoir pressure, and good mixing with high dispersion rate is expected. The oil production curves have the same shape, as well as GOR curves. The difference in oil rates can be explained with the bad representation of mass transfer between injection gas and reservoir oil by black oil model. The gas which is injected has some intermediate components which when mixed with oil and produced can be treated in compositional model as oil, giving higher oil rate than the black oil model.

Overall a good match between the compositional model and black oil model with Todd-Longstaff formulation of miscibility is achieved. Application of mixing parameter equal to 1 results in good match between the compositional model and the black oil model. This is different from the recommendations of Todd-Longstaff to use mixing parameter of 1/3 for field scale models. In this case, when MMP is much lower than the reservoir pressure, and it is reasonable to expect the fluids to form one phase very fast, and the dispersion zone to be larger than the grid blocks.

Several sensitivity simulations were run for different injection rates and half-cycle lengths to check if all the cases show good match with mixing parameter equal to 1 used. The injection rates of gas were set to 300000, 340000 and 420000 Sm<sup>3</sup>/d, and 6 months half-cycle with injection rate of 380000 Sm<sup>3</sup>/d was used as a case with new cycle. The results are presented on the figures 4.15 – 4.22



### **Gas injection rate sensitivity**

For the gas injection rate equal 300000 Sm<sup>3</sup>/d, the pressure match is good, oil production rate and GOR show the same behavior as for the previous case. The pressure match here suggests that for the original gas injection rate of 380000 Sm<sup>3</sup>/d the volumes of injected gas had different influence on the pressure for compositional runs and black oil runs. The gas break-through occurs almost at the same time for these models, but the pressure is maintained in the black oil case, where for the compositional case the volume of injected gas is not enough to maintain the pressure. The reason for this may probably be in different gas volumes calculations for the reservoir conditions. For the rate of 300000 Sm<sup>3</sup>/d, the volume of gas injected is not enough to avoid pressure drop to 303 bar, and the models give good match.

The results for the case with gas injection rate equal to 340000 Sm<sup>3</sup>/d are the same as for the previous case.

For the case with high gas injection rate of 420000 Sm<sup>3</sup>/d oil production rate and GOR show the same typical behavior. The pressure has the same tendency, though the amplitude can be different.

All of the cases showed good match in recovery between compositional model and black oil model, with error less than 1 %. The ultimate recovery predicted by compositional model is higher, but the difference between the compositional model and black oil model is always less than 1%.

### **Half-cycle length sensitivity.**

For the 6 months half-cycle length results of simulations are shown on the figure 4.21. The amount of total injected gas is the same as for the original case. The results show the same type of behavior as for the case with 12 months half-cycle. The GOR has bigger difference at the pick value. The difference reaches the value of 100 Sm<sup>3</sup>/Sm<sup>3</sup>. The difference in ultimate recovery is 1.7 %. The recovery factor plot is presented on the figure 4.22.

### **Summary**

The mixing parameter is the key parameter influencing the behavior of the model during miscible flood. It was found that the mixing parameter equal to 1 gives the best match with the compositional model. This means that there is large dispersion zone and gas and oil form one phase very fast. This is reasonable as the minimum miscibility pressure is 100 bar lower than the reservoir pressure.

The differences between the black oil and compositional models are due to different volume calculations for gas for reservoir conditions, poor representation of mass transfer of intermediate components for black oil model. Improvement of black oil PVT model, more detailed fluid behavior description can give better results. Whitson et. all published paper in 2000 called "Guidelines for Choosing Compositional and Black Oil models for Volatile Oil and Gas-Condensate Reservoirs". In this paper it is stated that compositional model should be used for studies of gas injection into oil reservoirs. The black oil model can only be used in oil reservoirs when there is minimal vaporization during lean gas injection, and if the model is developed using the provided guidelines. The black oil model recommended to use is made by splicing of black oil tables for the original reservoir oil and tables for swollen oil. To generate black oil tables for swollen oil multi-contact swelling experiment should be used, where injection gas is added to the original oil until the saturation pressure of swollen oil is higher than the expected injection pressure. The splicing is made by adding to the original black

oil table swollen oil properties from original bubble point to maximum expected pressure. Another option is to add depletion of fully swollen oil to saturation pressure of the original oil to black oil table of original oil. The final proposed method is to add to original black oil table data at the fully swollen saturation point. In this study the enriched gas is used, so for condensing/vaporizing mechanism of developed miscibility this might be the case why there is difference (vaporization mechanism is a part of this process), and as said previously the black oil model does not accurately describe mass transfer between the fluids.

It is worth mentioning that for the conditions expected during field scale simulations overall match is fairly good, and this study is enough to give an answer of what mixing parameter to use for the field scale simulation of miscible flooding of with black oil model.

In this study it was decided to go on with the available black oil table, as the generation of new tables was problematic due to difficulties in matching model to experimental data and in running the complicated procedure proposed by Whitson et. all. For the further studies where the SPE5 fluid will be used the described problem can be addressed and procedure proposed by Whitson et all. could be used.

## **4.2 Modeling of different design decisions for WAG.**

In this part of the study segment model was used to determine best completion scheme which will be used on the field scale model, and to show the basic trends when different WAG scenarios are implemented on the segment. The segment is a good representative of the part of the reservoir where the highest pore volume is. The black oil model with the Todd-Longstaff mixing parameter equal to 1 and modified PVT oil table is used for this study.

### **4.2.1 Completion scheme**

Different completion scenarios are tested out on the segment model to determine the most effective one. When choosing completion it is important to understand what kind of flow pattern is expected in each case. The permeability distribution in the cross-section is shown on the figures 4.23- 4.24. The vertical permeability has the same value as horizontal permeability for each grid block, but MULTZ function is used to input lower permeability in vertical direction.

The cross section can be divided into 3 parts with respect to horizontal permeability – high permeability layer in the upper part, lower permeability middle layer, and the layer in the bottom part of the segment with high and low permeability areas. The two lower rows of grid blocks are water filled and have no connection with the upper layers. It is expected that fast segregation due to density difference will take place and gas will flow in the upper most permeable layer, and water will flow through the bottom part of the reservoir. Presence of high permeability layer can result in decreased gas sweep efficiency and effectiveness of WAG injection.

The set up for the simulations is following: production well is set for constant production rate of 1000 Sm<sup>3</sup>/d with minimum BHP of 300 bar, the injection well is injecting 1200 Sm<sup>3</sup>/d of water for one year, then 4 WAG cycles with half-cycle length of 6 months are implemented with gas injection rate of 350000 Sm<sup>3</sup>/d. After that water is injected until the end of the production. The pressure is maintained at 300 bar. The production stops as water cut level of 80 % is reached.

The main goal here was to select the best completion scheme from the point of ultimate recovery. Production rate versus time is also compared. Overall 8 completion types were tested. The table 4.4 shows all the completion types. They basically can be grouped in the scenarios when production well is perforated in the upper, middle or lower interval and water is injected in the upper layer and gas is injected in the upper or lower layer. The changing completion during production was proposed here as well. This scenario technically can be implemented by dual completion. With the constraint of 80% water cut the production will stop earlier for the case with producing completion located in the lower area, and this can result in lower recovery in comparison to other scenarios, but the effectiveness of gas injection will be higher, as gas will increase sweep efficiency of attic oil. All of the cases are compared with water injection scenarios, when water is injected during the entire field life.

The results of simulations are presented on the figures 4.25 - 4.44.

Ultimate recoveries for all cases are presented in table 4.5.

For the case with completion of production well in the lower interval (type 2 and 3), the overall recovery is the worst, but the effect of WAG is the highest due to improved sweep efficiency (recovery of attic oil, which is not contacted during water flooding for this completion). The process is shown with several snapshots from type 2 completion case on the figure 4.45. The gas injected moves through the upper layer towards production interval. Once the oil is displaced there, each next gas slug injected will not displace much oil and improve recovery, as this upper layer saturated with gas acts like a good flow path for the injection gas. The observations show that some gas is being left in the upper part of the reservoir.

For the middle (type 1), and middle + bottom interval (type 4) of production completion ultimate recovery is better, as water reaches the well later and the maximum water cut also is reached later. In this case the effect of WAG is lower, as less area has improvement in sweep efficiency compared to water injection.

For the upper completion scheme the highest recovery is achieved due to longer production time until the water cut reaches the maximum value. WAG has almost no effect on sweep improvement, and EOR comes from the microscopic level – the microscopic recovery is increased for the areas contacted by gas. The process is shown with several snapshots from type 5 completion case on the figure 4.46. The gas slug is injected, and then it moves in the upper layer. After that water is being injected, pushing the oil towards the production well and upward. As a result of that upward movement of oil each extra injected gas slug will miscibly displace some of this oil pushed by water from lower layers. This is an effective scheme, where the gas slugs are not just flushing towards the production well through upper layer or accumulating in it, but they are miscibly displacing oil each time.

Injection scheme when water is injected in the upper interval and gas in the lower one has as expected better effect as more gas contacts oil (improved sweep efficiency of gas), but on this model the effect is minor.

To make gas displace more oil the changing completion scheme was proposed. The idea is to improve sweep efficiency of gas by forcing movement of gas in the downward direction. After gas is injected and water injection starts, the upper production interval opens to flow and gas slug is produced. Lower production interval is shut at this time. Then again upper interval is shut and new gas slug is injected, which contacts “new” oil which was pushed forward and upward to the upper producing interval on previous stage. At the same time gas will tend to move in the downward direction, what improves gas sweep efficiency. The snapshots of saturations are shown on the figure 4.47. As can be seen, there is isolated area, so there is potential for even higher production.

The oil production rate for type 5,6,7 completions declines faster after end of plateau production, but then it increases and is at high level almost until the end of production. For changing completion case compared with type 5,6,7 completions oil production rate is higher right after the end of the plateau, but it starts decreasing a bit earlier. “Steps” in production profile indicate changing completion periods.

The gas-oil ratio increases to higher values for type 5,6,7 completions, decreasing then after reaching pick value of GOR. For other completions GOR increases monotonically. This behavior is explained by break-through of gas slugs for types 5,6,7, while for other types some gas tends to accumulate in the upper parts of the reservoir, and move down with time, what leads to monotonical increase in GOR. For changing completion case GOR has ‘steps’ were GOR is low, indicating lower producing interval being open. GOR is somewhat lower for this case than for type 5,6,7 completion cases. But some gas is trapped in the isolated part of the reservoir so it could reach the level of these cases.

### **Summary**

The most successful completions are type 5, 6, 7 and changing completion case according to table 4.5. For the following simulations type 6 completion will be used as it is better to inject into wider interval to have more oil be contacted by gas. Gas will be injected into the lower interval, and water will be injected into the upper interval on the field scale model. Changing completion scenario will also be tested.

### **4.2.2 WAG parameters test**

Different WAG scenarios were simulated to see the effect of different cycle length, amount of cycles implemented, and accelerated production effect. Type 6 completion was used.

Kleppe et al. report in their paper published in 2006 that reasonable length of WAG cycle could be 3 months, but experts have opinion that WAG half - cycle length can have no effect on the recovery. It can also be impractical to use shorter cycles. There is also a trend that less gas is sold in summer so the WAG cycles can be arranged according to this. On the other hand there is opinion that shorter cycles

result in higher recovery. So 3, 6, 12 months half-cycles were tried, and simultaneous water and gas injection (SWAG) was tested as well.

The production well is set on constant production rate of 1000 Sm<sup>3</sup>/d, with minimum BHP equal to 300 bar. Water is injected at rate of 1200 Sm<sup>3</sup>/d for one year, then WAG cycles or SWAG are implemented so that the total injected gas amount is the same. The gas injection rate is 350000 Sm<sup>3</sup>/d for WAG. For SWAG gas injection rate is 175000 Sm<sup>3</sup>/d and water injection rate is 700 Sm<sup>3</sup>/d. The production is stopped when water cut reaches 80%. The results of simulations are presented on the figures 4.48 – 4.50 and table 4.6

From the table 4.6 it is seen that though difference in recovery is minor, there is clear trend that the recovery increases with application of shorter half-cycle, and reaches top value for SWAG. According to Kleppe et. al 2006, SWAG can be difficult to implement and there can be some practical difficulties associated with this technology, but all the cases will be tested on field scale model.

Accelerated production scenario was tested. The production well is set on constant production rate of 2000 Sm<sup>3</sup>/d, with water injection rate of 2400 Sm<sup>3</sup>/d for one year. WAG scenario with 6 months half-cycle length was implemented as in previous part, only changes were made in injection rates – 700000 Sm<sup>3</sup>/d for gas and 2400 Sm<sup>3</sup>/d for water. The case is compared with water injection and with WAG scenario with lower rates. The results are show on the figures 4.51 – 4.52 and table 4.7

As can be seen from the table 4.7, accelerated WAG gave significant improvement in recovery, increasing it by more than 2% in comparison with the original case, and almost by 4% when compared with water injection scenario. There is clear proof that accelerated WAG has better effect and results in big recovery increase. According to these results, accelerated scenario will be used in the field scale simulations. The segment is a good representative of the reservoir, as it is big enough and almost has the dimensions the zones between the wells will have in that part of the reservoir. So no upscaling of rates is required.

The effect of implementation of more cycles was also studied. The original case with 6 months half-cycle WAG was modified to have 2 times more cycles. The results of comparison of the original and modified scenarios are presented on the figures 4.53 – 4.55 and table 4.8.

From table 4.8 it is seen that the increase in number of cycles gave almost 1.5 % increase in recovery. This indicates that more oil is displaced by miscible gas injection if the number of cycles is increased, as was expected if type 6 completion scheme is used. It is worth notifying that GOR also increases almost two times higher, and oil production is prolonged.

## 5. FIELD PRODUCTION MODELING

In this part of study modeling of field production was performed. The reservoir description is available in Chapter 2. The reservoir is produced with 3 production wells, and 3 injection wells are used for water flooding or WAG injection. First, water flooding scenario was modeled to have the case with which WAG scenarios could be compared. After that different WAG scenarios with early time, late time and life time WAG as well as SWAG were tested. Here results obtained in previous parts of the study were used. All the recovery factor percentages refer to original oil in place.

### 5.1 Water flooding modeling

The reservoir is produced with 3 production wells, which are located in the middle of formation. 3 injection wells are used for water injection, which are located on the sides of the reservoir. The strategy is to displace oil from the sides of the reservoir to its central part. The production wells are located in the way that oil is drained from all parts of the reservoir, though there are several faults in the area. The well pattern is shown on the figure 5.1. The scenario is designed in the way that due to the faults each injection well influences mostly the production of one production well. So the injection well Inj\_1 is intended to displace oil towards Prod\_1 production well, and so on.

The completion strategy is used according to the study done in Chapter 4, where type 6 completion was recommended. This completion scheme implies perforation of production wells in the upper interval. During water flooding the water is injected into upper interval as it will be done during WAG. The water moves to the bottom of reservoir fast so practically there will be not much difference in which interval water is be injected.

The set up for the simulations is the following: all production wells are set on the constant production rate of 2000 Sm<sup>3</sup>/d, with bottomhole pressure limit of 300 bar. The water is injected at the rate of 2400 Sm<sup>3</sup>/d for all the wells, with maximum bottomhole injection pressure of 350 bar. The production well is closed when the water cut reaches the limit of 90%, and the injection rates are adjusted to avoid pressure increase over 350 bar. When the last well is closed, simulation stops. The results are presented on the figures 5.2 – 5.5.

The oil production rate shows typical behavior with a plateau in the beginning of production, and then decline. As production wells are closed pressure starts increasing but it does not exceed the value of 350 bars due to pressure control while injection. Injection rates for each well can be seen on the figure 5.5.

The production wells as well show typical behavior. As for the well Prod\_2, the area where the well is located is separated from the injection well Inj\_2 by the fault, which is permeable, but the well goes on decline faster as the water injected from the well Inj\_2 starts contributing to material balance within that volume around Prod\_2 later. As can be seen, as the water finally reaches that area, the rate starts increasing. The water cut reaches the limit on the well Prod\_3 first, later wells Prod\_1 and Prod\_2 are closed.

The ultimate recovery factor of the field reaches high value of 72.83 %, so improvement of recovery is challenging task. The snapshots of saturations at different time of production are shown on the figures 5.6 – 5.10.

As can be seen from the figures, flooding works as it was expected, with water from each injection well moving towards assigned production well. The flooding is successful from the point of horizontal and vertical sweep efficiency. The oil which is left is mainly trapped in the isolated areas. Some oil is left right under the injection well Inj\_1 but as can be seen on the figure 5.9, that layer is well drained. On the figure 5.10 it can be seen that one not well drained layer is isolated from the rest of the reservoir and it is very difficult to drain (even on the original Gullfaks model it is not well drained). This layer is highly saturated with water originally.

## **5.2 Water alternating gas modeling**

The reservoir might look not the best candidate for WAG injection, as there is no dip, there is layer at the top of formation with good permeability, and recovery after water flooding is high.

There is no sweep efficiency improvement expected, as there is no attic oil being left after water flooding. In this work it is investigated if WAG can give reasonable improvement of reservoir performance and be successful on this type of reservoirs, or it is better to just do water flooding.

According to the segment modeling, the recovery improvement from WAG is expected on microscopic level. The task is to make more oil being miscibly displaced by gas. For this purpose several schemes of WAG injection were tested. They include early time WAG injection, when gas slugs are injected in the early time in production and then continued with water injection, late time WAG, when gas slugs are injected after some water flooding is completed, and lifetime WAG, when injection cycles go on for almost the entire field life. Different injection half-cycles were tried, as well as SWAG.

The type 6 completion is used for all the cases. The wells have the same location as in water injection case, with only difference that injection wells are perforated in the bottom layers for gas injection. Changing completion scheme has also been tested.

For modeling of miscible displacement Todd-Longstaff model was used, where minimum miscibility pressure was set to 195.9 bar, according to Chapter 3 results. As there was no data with respect to the residual oil saturation after miscible displacement, it was not used during study, but sensitivity on this parameter was run.

### **5.2.1 Early time WAG injection**

This scheme implies that the gas slugs are injected after one year of water injection.

The production wells are put on the constant production rate of 2000 Sm<sup>3</sup>/d, with minimum bottomhole pressure of 300 bar. The injection wells are injecting water for one year at the rate of 2400 Sm<sup>3</sup>/d. After one year of water injection, the WAG injection is implemented for 4 years, with the half-cycle lengths of 12, 6, 3 months and SWAG. Gas injection rate is 700000 Sm<sup>3</sup>/d, water injection rate – 2400 Sm<sup>3</sup>/d, for SWAG – 350000 Sm<sup>3</sup>/d and 1200 Sm<sup>3</sup>/d respectively. The limit on maximum injection bottomhole pressure is 350 bar. Overall amount of gas injected is almost the same. After that

water is injected at rate of 2400 Sm<sup>3</sup>/d until the end of production. The wells are closed when the water cut limit of 90% is reached. After the last well is shut, simulation stops. All results are shown on the figures 5.11 – 5.17 and in the table 5.1.

As can be seen from the table and figures, oil production is longer for WAG scenarios than for water flooding. The plateau length is the same. Oil production rate is higher for water flooding case after the start of decline, and this is because at this time gas break-through occurs for WAG. After some time oil rate for water flooding drops, when at this time oil production is high for the WAG scenarios. The gas-oil ratio for the field shows typical behavior with fluctuations when the gas slugs reach production wells. For 3 months half-cycles and SWAG the increase in GOR occurs with no fluctuations. The maximum GOR value is 360 Sm<sup>3</sup>/Sm<sup>3</sup>. The plots for the wells show that does not reach the production well Prod\_2. On the figure 5.16 it can be seen that the gas injected in the well Inj\_2 is flowing around the fault and towards the well Prod\_1, so the sweep of the gas is not really good in the area between wells Inj\_2 and Prod\_2. The reason for this is the fault with low permeability between these wells.

On the figure 5.17 it can be seen that the gas as expected is moving through the upper layer. The improvement of recovery occurs on the microscopic level, as water also displaces oil in this area during water flooding scenario. The shorter cycle half-length generally shows higher efficiency in recovery improvement (it can be seen on the recovery plot), with SWAG showing the best results (though the results for all the cases are close). This is due to the fact that miscible displacement occurs more times as the cycles are shorter – the gas moves forward to the production well, then on the water injection cycle oil is pushed forward and upwards, and next gas slug displaces this oil which was pushed upwards by water (figure 5.16).

Implementation of these WAG scenarios results in improvement of oil recovery by 3.32 – 3.6 %, what is 1.11 – 1.17 million of Sm<sup>3</sup> of oil produced. The ratio of oil produced to gas injected is in the range 724 – 767 Sm<sup>3</sup>/MSm<sup>3</sup>. It is worth mentioning more than 80% of injected gas is produced back, so if this is taken into account that ratio increases up to 5000 Sm<sup>3</sup>/MSm<sup>3</sup>.

## 5.2.2 Late time WAG injection

This scheme implies that the gas slugs are injected after 3 years of water injection.

The production wells are put on the constant production rate of 2000 Sm<sup>3</sup>/d, with minimum bottomhole pressure of 300 bar. The injection wells are injecting water for 3 years at the rate of 2400 Sm<sup>3</sup>/d. After 3 years of water injection, the WAG injection is implemented for 4 years, with the half-cycle lengths of 12, 6, 3 months and SWAG. Gas injection rate is 700000 Sm<sup>3</sup>/d, water injection rate – 2400 Sm<sup>3</sup>/d, for SWAG – 350000 Sm<sup>3</sup>/d and 1200 Sm<sup>3</sup>/d respectively. The limit on maximum injection bottomhole pressure is 350 bar. Overall amount of gas injected is almost the same. After that water is injected at rate of 2400 Sm<sup>3</sup>/d until the end of production. The wells are closed when the water cut limit of 90% is reached. After the last well is shut, simulation stops. All results are shown on the figures 5.18 – 5.23 and in the table 5.1

As can be seen from the results, production time is longer than for water flooding, but is shorter than for early time WAG injection. The behavior of the production rate is typical when compared to



water flooding scenario - after start of WAG injection production rate drops, but the production goes for longer time and then becomes higher than for the water flooding case.

For the GOR, the higher values than for the early time injection are observed for these cases. Overall field GOR is somewhat higher than for the early time WAG, but the GOR for the wells has significant increase up to 1500-1700 Sm<sup>3</sup>/Sm<sup>3</sup>. As before the production well Prod\_2 does not show any increase in GOR, what means gas is not reaching this well.

Late time WAG injection scenarios results in overall increase in recovery by 3.46 – 3.76 %, what is 1.14 – 1.198 million Sm<sup>3</sup> of oil. The better performance is for the shorter half-cycle length of WAG injection (from the point of production rate and ultimate recovery) and SWAG. The ratio of oil produced to gas injected is in the range 742 – 781 Sm<sup>3</sup>/MSm<sup>3</sup>. Taking back production into account this value can increase up to 3803 – 4410 Sm<sup>3</sup>/MSm<sup>3</sup>.

### 5.2.3 Life time WAG injection

For these scenarios WAG continues for almost all the period of field production. The production wells are put on the constant production rate of 2000 Sm<sup>3</sup>/d, with minimum bottomhole pressure of 300 bar. First, water is injected for one year at the rate of 2400 Sm<sup>3</sup>/d for each well. Then WAG is initialized with gas injection rate of 700000 Sm<sup>3</sup>/d and water injection rate of 2400 Sm<sup>3</sup>/d, for SWAG – 350000 Sm<sup>3</sup>/d and 1200 Sm<sup>3</sup>/d respectively. The maximum injection bottomhole pressure is set to 350 bar. The half-cycle lengths used here are 12, 6, 3 months and SWAG. The wells are closed when the water cut limit of 90% is reached. After the last well is shut, simulation stops. As was observed in the previous cases, gas injected into the well Inj\_2 moves to production well Prod\_1. So for the lifetime WAG injection scenarios were tested when only several slugs of gas are injected into well Inj\_2. The results of simulations are shown on the figures 5.25 - 5.33 and table 5.1.

Oil production goes on for significantly longer time than for other cases. In comparison to water flooding scenario, production is prolonged for 4-5 years. The oil production rate for these WAG scenarios is lower than for water flooding after plateau ends, but later with production it becomes higher than for the water flooding. The decline is more stable. As for the GOR, it is as high as for the late time injection. It must be said that more gas is obviously being injected in these scenarios, so it is expected that the GOR will be high. The GOR for the Prod\_3 well reaches high values, but the well goes on producing significant amounts of oil (Figure 5.29). That part of reservoir continues to undergo miscible displacement of oil which is pushed up to the well by water on each gas cycle. Another observation is that the shorter the half-cycle is, the lower is the GOR.

For the cases where injection of gas into well Inj\_2 was limited, the oil production stops earlier. The overall trend is that the recovery in these cases is quite lower. However, much less gas is required to obtain that recovery factors, and from the point of amount of oil produced per gas injected these cases are the most effective.

Overall ultimate recovery increase is in the range of 4.63 – 5.55 %, what means extra 1.37 – 1.55 million of Sm<sup>3</sup> of oil. The amount of oil produced per amount of gas injected varied in the range of 437 – 450 Sm<sup>3</sup>/MSm<sup>3</sup> for the case when the gas was injected into all wells equally, and in the range

576 – 596 Sm<sup>3</sup>/MSm<sup>3</sup> for the case when limited gas injection was implemented for well Inj\_2. Generally as expected lifetime injection resulted in highest recovery, as more times (cycles) oil was displaced miscibly.

#### **5.2.4 Changing completion scheme lifetime WAG**

For the changing completion scenario 6 months half-cycle lifetime WAG and 3 months half-cycle lifetime WAG scenarios were taken as basis. All the parameters are kept the same, the only difference is that the wells Prod\_1 and Prod\_3 have changing completion scheme realized. It is expected that this scheme will allow increasing the recovery by making more oil being displaced miscibly by gas. This is achieved by changing flow directions of gas slugs when they reach production wells. The simulations were run also for the scenarios when the gas is not injected for the entire life into well Inj\_2. The results of simulations are presented on the figures 5.34-5.44 and table 5.1.

As can be seen from the figure 5.34, the oil production rate shows sharp changes, which refer to the period of changing completion intervals. As for any other case production drops to the lower levels than for water flooding after the end of the plateau, but longer production time and more stable decline results at the higher rates for WAG at the late time. When there is limited gas injection in Inj\_2 well, then the production ends up earlier.

For the gas-oil ratio, it can be seen that here the same situation with sharp “steps” in GOR is observed. The level of values is in the same range as for the life time scenarios of WAG discussed before. The difference for the case with limited gas injection into well Inj\_2 is that at the very late time there is no last increase in GOR. This influences the earlier production stop.

The gas – oil ratio of the wells shows different picture when compared with previous cases. For this scenario production in the well Prod\_3 stops due to water-cut constraint, and the gas reaches production well Prod\_2.

As can be seen from the figure 5.38 - there is good improvement on sweep efficiency in the upper layer, as well as improvement in vertical sweep. As can be seen the gas moves to the production well Prod\_2 from the Inj\_2 well and from the area of Prod\_3 well. The sweep efficiency is improved in the upper layer. As well, it can be seen on the figures 5.39 and 5.43, vertical sweep of gas is improved compared to the conventional completion. The expected movement of the gas in direction of lower completion is achieved. The lower improvement effect for the situation with limited gas injection as due to that fact that less gas accumulates in the upper zone and it is not moving downwards. This does not allow improvement in vertical sweep for gas. It can be seen from the figures 5.39 and 5.42 that the horizontal sweep is improved by gas moving to the production well Prod\_2. The significant improvement comes from the miscible displacement of oil by gas towards the completions located in the lower interval, and significant amount of oil is produced extra. Poor improvement of performance for limited gas injection is a result of lower vertical sweep improvement. It can be seen that even if the sweep in horizontal plane is improved, there is no much effect in the vertical direction what results in much lower improvement of performance.

Overall there is improvement of recovery for all cases, but there is better improvement for the cases when gas is injected into all wells. The recovery and total oil produced comparison is given in the table 5.2. It can be seen that the best improvement in recovery is 1.28-1.32%, what is equivalent to extra 251950 – 262700 Sm<sup>3</sup> of oil. This is the increase of EOR produced oil by 17%. The value for oil produced per gas injected is the best, though the back production of gas is lower.

### **5.2.5 Residual oil saturation after miscible flooding sensitivity**

In the cases simulated residual oil saturation to miscible flooding was not used. This basically means that the oil saturation in the cell can go to zero value if the gas is displacing oil. For all the simulations above the oil saturation didn't go down to zero value, but here it was tested what influence on the recovery will be if residual oil saturation is used. All the field scale cases were tested for this. The residual oil saturation to miscible flooding was set to 2%. The results are presented in the tables 5.3 and 5.4. What can be seen is that the overall decrease in recovery is generally less than 0.5 %, and in terms of oil production, the amount of extra oil produced reduced by 5-7% (extra oil is the difference between oil produced by water injection and WAG). This means that if the residual oil saturation is set to 2%, then the influence of that is not really big. The residual oil saturation to water flooding is 15%, so it is reasonable to think that if the residual oil saturation after miscible flooding is set to 10%, there generally would be no purpose in WAG for this type of reservoir, as here the improvement in recovery comes from improvement of displacement on microscopic level. According to this it can be stated that it is very important to do experiments on the residual oil saturation. This parameter can be critical in evaluation of reasonability of the gas injection.

## **5.3 Discussion of results of field scale modeling**

Several different WAG scenarios were tested, including early time WAG, late time WAG and lifetime WAG. For all these simulations results obtained in previous parts of the study were used. Different injection half-cycles and SWAG were tested. Though the reservoir might look not the best candidate for the WAG, improvement in reservoir performance was achieved.

### **Early time WAG injection**

Early time WAG injection shows increase in oil recovery up to 3.6%, what is equivalent to 1167060 Sm<sup>3</sup> of oil. There is no big difference from the point of reservoir performance for the cases with different WAG cycles, so generally any scenario can be used for EOR. To achieve this recovery, gas injection of 21% of pore volume is required, and more than 80% of the gas will be back produced. From the practical point of view, it is better to go for any WAG case than for SWAG as there is no much difference in results. The oil produced per gas injected ratio is 767 Sm<sup>3</sup>/MSm<sup>3</sup> for the best scenario, what can be considered quite high for this type of reservoir. A lot of gas is being back produced. The geology of this reservoir implies that the gas will be moving fast through the upper layer, but the improvement in results is achieved by designing the production in the way that on the gas injection cycle gas contacts oil which is pushed upwards and towards the well by water. Overall this scenario can be considered for implementation and is successful for this type of reservoir.

### **Late time WAG injection**

Late time WAG injection has somewhat better results than early time injection, with recovery increase reaching the value of 3.76%, what is 1198660 Sm<sup>3</sup> of oil. In this scenario difference between different half-cycles is higher, but still any case can be used as a possible miscible displacement scenario. Late time scenario shows higher GOR values than for the early time case. Here the same amount of gas is required to achieve this recovery, and more than 80% of it will be back produced. The oil produced per gas injected value here is higher than for the early time behavior – maximum is 783 Sm<sup>3</sup>/MSm<sup>3</sup>. This scenario shows better performance than the early time case and as well can be considered as an option for WAG.

### **Lifetime WAG injection**

In this case the increase in recovery was significantly higher than for the previous cases. Injection of more gas and for almost entire field life resulted in increase of recovery by 5.5%, what for this type of reservoir can be considered as high value. The equivalent of this is the value of 1549710 Sm<sup>3</sup> of oil. The limited injection was tested as well, when less gas is injected into the well Inj\_2. For these cases recovery is significantly lower, but the amount of gas required is also lower – 47 % of HCPV ( hydrocarbon pore volume) for the normal scenario and 33% of HCPV for limited case. Generally the oil produced per gas injected ratio is lower for the lifetime injection, and is 450 Sm<sup>3</sup>/MSm<sup>3</sup> for the best case. With limited gas injection this value increases to 596 Sm<sup>3</sup>/MSm<sup>3</sup>. Here the difference in half-cycle length is more significant. Generally as well any case can be implemented, but 3 months and 6 months half-cycle scenarios seem to be the most reasonable. The SWAG has no improvement in comparison to 3 months half-cycle case. The amount of gas back produced reaches the level of 89%. If there is the limit on the gas injection available, one can go for limited injection scenario which is also reasonable. What is clear that increase in the % HCPV injected resulted in significant increase in reservoir performance, meaning that the extra injection gas is not just flushing through the high permeability channels. The expected mechanism of EOR is working.

### **Changing completion scenario of WAG**

The changing completion was tested on the segment model, and then was tried on the field model. The lifetime WAG injection cases with 6 months and 3 months half-cycles were modified for this purpose. This scenario shows the best recovery out of all cases, with the maximum recovery increase reaching high value of 6.83%, what is equivalent of the 1801660 Sm<sup>3</sup> of oil produced extra. This scenario showed improvement in the vertical sweep efficiency of gas, with the gas as expected pushing oil in the direction of the lower completions during gas injection cycle, and in horizontal sweep efficiency of gas in the upper layer. The cases with limited gas injection didn't show any of the significant improvement of performance, though the horizontal sweep of gas in the upper layer was improved as well. There was not seen any real changes in vertical sweep of gas for this cases. The effectiveness of the changing completion scenarios is better as well from the point of oil produced per gas injected. But the amount of back produced gas is lower here and is 83 %. For the cases with limited injection it is even lower with 77%. Overall these cases are the most successful among all the scenarios tested from the point of recovery, but technical challenge of implementation of this scenario may be faced.

All the scenarios showed improvement in reservoir performance and worked as expected. The late time scenarios can be considered the better choice than the early time scenarios as they show higher recovery and better produced oil per injected gas ratio, with the same amounts of gas used. There is practically no difference what half-cycle to use as the performance here is not really changing. High back production of gas also favors the economy of the possible project.

It was shown that more cycles implemented result in recovery increase, so the lifetime WAG injection can be used. These scenarios show the best performance, with a lower produced oil per injected gas ratio, but the significantly higher recoveries. Another option is to use limited gas injection. For these scenarios half-cycle length plays a bit more important role but still any case can be used.

The changing completion scenario is the best from the point of oil recovery, and is better than any of lifetime WAG scenarios from the point of reservoir performance and effectiveness. For this type of reservoir it results in high recovery, and is considered successful case for the WAG on this type of fields.

Overall it is possible to achieve good effective recovery from these types of fields. The rule of thumb is to use more cycles, and select proper completion scheme for these field. Late time WAG can be used as an option for recovery method and can be successful. The fact that most of the injected gas is back produced may be a good economical reason for the implementation of WAG. It is very important to run the experiments on residual oil saturation after miscible gas displacement. This parameter can seriously influence the decision making for this type of reservoirs, where no improvement in sweep efficiency can be achieved. For the studies done this parameter was tested with the value of 2%, not making big difference in results with only 5-7,5 % reduction in extra oil produced. But the value of 10% may mean that there is no purpose in running WAG as the residual oil saturation to water is 15%.

## 6. CONCLUSIONS

The study of possibility of implementation of water alternating gas (WAG) injection on the field with high permeability upper layer and with no dip was conducted. The problems described in the introduction were addressed.

The conclusions are summed up below:

1. Miscibility of injection gas and reservoir oil was studied. Slim tube simulation results with no numerical dispersion and equation of state based multicell calculations show good consistency. The minimum miscibility pressure (MMP), determined with multicell equation of state based procedure, is 195.9 bar. The MMP calculated with slim tube simulations is in the range of 193.1 – 196.5, and is close to 196 bar. The mechanism of developed miscibility is condensing/vaporizing.
2. The black oil model and compositional model are verified by running depletion and water injection scenarios on the segment model, extracted from the field scale model. The black oil model provided by Schlumberger for the SPE5 Comparative study shows mismatch with the compositional model. For the depletion case the pressure drop in the reservoir was predicted higher by black oil model than by compositional model, what is the evidence of poor formation volume factor description for undersaturated oil. The black oil table for oil was modified to give good match with fine grid compositional model.
3. For WAG scenario mixing parameter was obtained to give match between coarse grid black oil model with Todd-Longstaff formulation of miscible displacement and fine grid compositional model. It was found that the value of mixing parameter equal to 1 shows the best match. This means that the dispersion rate is very high, and fluids form one phase very quickly. It can be reasonable because the reservoir pressure is 100 bar higher than the MMP, and one phase is formed fast. The one problem observed was connected with underestimation of oil rate by black oil model. This can be connected with not correct representation of mass transfer of intermediate components between enriched injection gas and reservoir oil. The generation of detailed black oil PVT tables can possibly solve this kind of problem. The procedure for modification of black oil for gas injection studies was proposed in the paper “Guideline for Choosing the Compositional and Black Oil models for Volatile Oil and Gas-Condensate Reservoirs” by Whitson et al in 2000.
4. The segment model was used to determine the completion scheme for this reservoir. The case with completion of production well in the upper interval and injection of water in the upper interval and of gas in the lower interval was found to be the best. The flow pattern in this case results in the possibility to increase oil recovery by making more oil being displaced by gas miscibly on each cycle. Oil is displaced by water towards the production well and upwards to the upper interval, where it is displaced by gas during gas injection.
5. The changing completion scheme was proposed to improve oil recovery by improvement of sweep efficiency of gas. For this case upper production interval is open to flow during water injection, and lower production interval is opened during gas injection. During gas injection cycle gas is forced to move in downward direction, what improves vertical sweep efficiency of gas.
6. Influence of number of cycles, half-cycle length and injection rate was tested on the segment model. It was found that the shorter the half-cycle is, the higher is the ultimate recovery.

Simultaneous water and gas injection (SWAG) is the most effective. Accelerated production shows the best recovery as well, because more oil is contacted by gas. For the completion scheme used the increase in number of cycles resulted in improvement of recovery.

7. 19 WAG injection scenarios were tested and compared to water flooding scenario. For this type of field water flooding shows very good results, with 72% oil recovery and good sweep efficiency. Field scale simulations showed that it is possible to achieve improvement in oil recovery and WAG injection can be effective in this type of reservoirs, with the proper techniques applied. All important information about the results of simulations is summed up in table 5.1. The highest improvement in recovery can be achieved by lifetime WAG injection, what can increase the recovery by 5.5 %. The ratio of oil produced per gas injected reaches the value of 596 Sm<sup>3</sup>/MSm<sup>3</sup>, what is high for this type of reservoir. Late time and early time WAG injection showed no big difference in improvement of oil recovery, though late time scenarios resulted in slightly better increase in recovery, with maximum of 3.4%. Late time and early time schemes are the most effective from the point of oil produced per gas injected ratio, with maximum of 783 Sm<sup>3</sup>/MSm<sup>3</sup>. More than 80% of injected gas is backproduced, what makes WAG very effective technology for the field. Implementation of WAG injection instead of water injection can results in delayed gas sales, what has influence on net present value. The resulting improvement of oil recovery was due to the improvement of microscopic recovery in the areas where oil was displaced by gas. Overall late time and life time cases can be considered for implementation.
8. The application of shorter half-cycle length and SWAG didn't show very much difference in the results, though overall trend of better performance with shorter cycles used was observed. Cases with 3 months half-cycle and SWAG gave similar results, so due to operational problems associated with SWAG it is better to use 3 months half-cycle WAG.
9. Changing completion scheme was tested for the life time scenarios. These cases showed improvement of oil recovery compared with the standard completion scheme. The improvement of recovery for the 3 month half-cycle case reached 6.83 %, with oil produced per gas injected ratio of 526 Sm<sup>3</sup>/MSm<sup>3</sup>. Changing completion scheme showed the expected improvement of the reservoir performance.
10. It is important to run experiments for determination of residual oil saturation after miscible flooding. This parameter was tested for the value of 2%, what didn't make big difference in the results, with extra oil production decrease by 5-7.5%. But the value of residual oil saturation after miscible flooding equal to 10% may mean that there is no purpose to run WAG injection on this type of reservoir when the residual oil saturation after water flooding is 15%. As no sweep efficiency improvement by gas injection can be achieved on this reservoir, the value of residual oil saturation should be well determined.

The models which were used are available from electronic sources, submitted with this thesis.

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## 8. NOMENCULATURE

HCPV – Hydrocarbon Pore Volume  
FOPT – Field Oil Production Total  
FOPR – Field Oil Production Rate  
FGIT – Field Gas Injected Total  
FWIR – Field Water Injection Rate  
FGOR – Field Gas-Oil Ratio  
FGIR – Field Gas Injection Rate  
FWIR – Field Water Injection Rate  
FWCT – Field Water Cut  
FPR- Field Pressure  
FOE – Field Oil Recovery Factor  
WOPR –Well Oil Production Rate  
WGOR – Well Gas-Oil Ratio  
MMP – Minimum Miscibility Pressure  
MME- Minimum Miscibility Enrichment  
WAG – Water Alternating Gas injection  
SWAG – Simultaneous Water And Gas injection  
PVT – Pressure Volume Temperature  
BO – Black Oil  
 $\omega$  – Todd-Longstaff mixing parameter  
 $\mu$  - viscosity  
 $S$  – saturation  
 $\rho$  – density  
M- mobility ratio

### Subscripts:

o - oil  
m - mixture  
n - nonwetting  
g - gas  
w - wetting

## APPENDIX A. Tables

Table 4.1 Parameters of the grid systems

	Coarse grid model	Fine grid model
<b>Number of grid blocks in X-direction</b>	8	16
<b>Number of grid blocks in Y-direction</b>	17	34
<b>Number of grid blocks in Z-direction</b>	16	32
<b>Total number of grid blocks</b>	2176	17408
<b>Length of segment in X-direction (approx.), m</b>	870	870
<b>Length of segment in Y-direction (approx.), m</b>	430	430
<b>Height of segment (approx), m</b>	200	200

**Table 4.2 Black oil PVT tables from the original SPE5 data file of Eclipse (units converted to metric units)**

Oil PVT table	Gas PVT table
PVTO	PVDG
0.0000 1.01 1.0348 0.310 /	1.01 1.253253 0.011
20.945 34.47 1.1017 0.295 /	34.47 0.031454 0.012
39.647 68.85 1.1478 0.274 /	68.95 0.014211 0.013
47.679 82.74 1.1677 0.264 /	82.74 0.011428 0.014
60.806 103.42 1.1997 0.249 /	103.42 0.008755 0.016
75.072 124.11 1.2350 0.234 /	124.11 0.007106 0.018
85.314 137.89 1.2600 0.224 /	137.89 0.006342 0.019
102.02 158.74 1.3010 0.208	158.74 0.005504 0.022
227.69 1.2988 0.235	172.37 0.005101 0.023
296.63 1.2966 0.260 /	206.84 0.004383 0.027
112.94 172.37 1.3278 0.200 /	241.32 0.003927 0.031
140.58 206.84 1.3956 0.187 /	275.79 0.003610 0.034
168.20 241.32 1.4634 0.175 /	310.26 0.003378 0.037
195.83 275.79 1.5312 0.167 /	330.95 0.003266 0.038 /
223.47 310.26 1.5991 0.159 /	
240.05 330.95 1.6398 0.155	
379.21 1.6305 0.168 /	

**Table 4.3 Changes made in the original PVT table of oil**

Original BO table	Modified BO table
102.02 158.74 1.3010 0.208	102.02 158.74 1.3010 0.208
227.69 1.2988 0.235	227.69 1.2799 0.235
296.63 1.2966 0.260 /	296.63 1.2620 0.260 /
112.94 172.37 1.3278 0.200 /	112.94 172.37 1.3278 0.200 /

**Table 4.4 Completion types**

<b>Completion type</b>	<b>Completion ranges ( Cells range in Z-direction 2-17, water filled grid block rows 16, 17)</b>
Type 1	Producer: 6 – 12 Water injector: 2 – 5 Gas injector: 6 - 12
Type 2	Producer: 12 – 15 Water injector: 2 – 5 Gas injector: 6 - 12
Type 3	Producer: 12 – 15 Water injector: 2 – 5 Gas injector: 2 – 5
Type 4	Producer: 6 – 15 Water injector: 2 – 5 Gas injector: 2 – 5
Type 5	Producer: 2 – 6 Water injector: 2 – 6 Gas injector: 11 – 12
Type 6	Producer: 2 – 6 Water injector: 2 – 6 Gas injector: 11 – 15
Type 7	Producer: 2 – 6 Water injector: 11 – 15 Gas injector: 11 – 15
Type 8 Changing completion	Producer interval while water injection: 2 – 6 Producer interval while gas injection: 11 - 15 Water injector: 11 – 15 Gas injector: 11 – 15

**Table 4.5 Ultimate oil recovery for different completion schemes**

	<b>Ultimate oil recovery (%)</b>		<b>Recovery improvement (%)</b>
	<b>Water injection</b>	<b>WAG</b>	
<b>Type 1</b>	71.77	75.72	3.95
<b>Type 2</b>	54.67	64.75	10.08
<b>Type 3</b>	54.67	64.73	10.06
<b>Type 4</b>	70.9	74.91	4.01
<b>Type 5</b>	79.74	81.14	1.4
<b>Type 6</b>	79.74	81.09	1.35
<b>Type 7</b>	79.74	81.08	1.34
<b>Type 8</b>	79.74	81.75	2.01

**Table 4.6 Oil recovery factors for different WAG half-cycle lengths and SWAG**

<b>Half-cycle length</b>	<b>Oil recovery (%)</b>
<b>12 months</b>	80.94
<b>6 months</b>	81.07
<b>3 months</b>	81.19
<b>SWAG</b>	81.37

**Table 4.7 Accelerated production recovery factor**

<b>Scenario</b>	<b>Oil recovery (%)</b>
<b>Accelerated water injection</b>	79.5
<b>Accelerated WAG</b>	83.46
<b>Lower rate water injection</b>	79.74
<b>Lower rate WAG</b>	81.07

**Table 4.8 Number of cycles test - recovery factor**

<b>Scenario</b>	<b>Oil recovery</b>
<b>Original number of cycles</b>	81.07
<b>2 times more number of cycles</b>	82.51

Table 5.1 Simulation results for field model

CASE №		Half-cycle	Production time	Cumulative oil production	% HCPV injected	Recovery factor	RF increase	Total gas injection	Total back produced gas	EOR oil produced	Oil / gas injected	Oil / gas injected (with back production)
		months	years	Sm3		%		MSm3	MSm3	Sm3	Sm3/MSm3	Sm3/MSm3
1	Early time WAG	12	11.5	1.50E+07	21.0	76.15	3.32	1535	1326	1110700	724	5324
2		6	11.5	1.51E+07	20.8	76.43	3.6	1522	1292	1167060	767	5067
3		3	11.5	1.50E+07	20.9	76.2	3.37	1531	1279	1120990	732	4444
4		SWAG	11.5	1.50E+07	21.0	76.28	3.45	1534	1261	1137380	741	4160
5	Late time WAG	12	11.0	1.50E+07	21.0	76.29	3.46	1533	1275	1137540	742	4410
6		6	10.5	1.51E+07	20.8	76.43	3.6	1523	1246	1165920	766	4211
7		3	10.5	1.51E+07	20.9	76.59	3.76	1531	1236	1198170	783	4062
8		SWAG	10.5	1.51E+07	21.0	76.59	3.76	1534	1219	1198660	781	3803
9	Life time WAG	12	13.0	1.53E+07	42.0	77.46	4.63	3070	2744	1368650	446	4198
10		6	13.5	1.54E+07	46.8	78.11	5.28	3425	3051	1495710	437	3994
11		6 (limited)	12.5	1.53E+07	32.9	77.56	4.73	2410	2103	1389390	576	4524
12		3	13.5	1.54E+07	47.1	78.38	5.55	3444	3049	1549710	450	3925
13		3 (limited)	12.5	1.53E+07	33.1	77.84	5.01	2423	2094	1443390	596	4381
14		SWAG	13.0	1.54E+07	47.2	78.31	5.48	3451	3040	1538630	446	3742
15		SWAG (limited)	13.0	1.53E+07	33.2	77.62	4.79	2429	2092	1401480	577	4166
16	Lifetime changing completion	case 10	12.5	1.56E+07	46.8	79.43	6.6	3425	2860	1758410	513	3111
17		case 11	12.0	1.53E+07	32.9	77.67	4.84	2410	1866	1410740	585	2591
18		case 12	12.5	1.57E+07	46.8	79.66	6.83	3422	2833	1801660	526	3059
19		case 13	12.0	1.53E+07	33.0	77.84	5.01	2415	1837	1444510	598	2503
Wat Inj			9.4	1.39E+07		72.83	-	-	-	-	-	-

**Table 5.2 Comparison of performance of conventional completion and changing completion**

Case	Improvement in recovery (%)	Improvement in total production (Sm3)
6 months half-cycle	1.32	262700
6 months half – cycle with limited injection	0.11	21350
3 months half-cycle	1.28	251950
3 months half – cycle with limited injection	0	1120

**Table 5.3 Simulation results with residual oil saturation after miscible flooding equal to 2%**

CASE №		Half-cycle	Cumulative oil production	Recovery factor	RF increase	EOR oil produced
		months	Sm3	%		Sm3
1	Early time WAG	12	1.49E+07	75.82	2.99	1046890
2		6	1.50E+07	76.11	3.28	1103080
3		3	1.49E+07	75.86	3.03	1053210
4		SWAG	1.50E+07	75.91	3.08	1064470
5	Late time WAG	12	1.50E+07	75.95	3.12	1071710
6		6	1.50E+07	76.08	3.25	1097880
7		3	1.50E+07	76.22	3.39	1125750
8		SWAG	1.50E+07	76.21	3.38	1124090
9	Lifetime WAG	12	1.52E+07	76.99	4.16	1276160
10		6	1.53E+07	77.58	4.75	1392150
11		6 (limited)	1.52E+07	77.19	4.36	1316820
12		3	1.53E+07	77.83	5	1442060
13		3 (limited)	1.53E+07	77.45	4.62	1366660
14		SWAG	1.53E+07	77.75	4.92	1426090
15		SWAG (limited)	1.52E+07	77.23	4.4	1324870
16		Lifetime changing completion	case 10	1.55E+07	78.79	5.96
17	case 11		1.52E+07	77.21	4.38	1321080
18	case 12		1.56E+07	78.98	6.15	1667940
19	case 13		1.52E+07	77.35	4.52	1347890
Wat Inj			1.39E+07	72.83	-	-



**Table 5.4 Recovery factor and total oil production decrease for the residual oil saturation after miscible flooding of 2%.**

<b>CASE №</b>		<b>Half-cycle</b>	<b>Recovery factor difference</b>	<b>EOR oil produced difference</b>	<b>EOR oil produced difference</b>
		<b>months</b>	<b>%</b>	<b>Sm3</b>	<b>%</b>
<b>1</b>	<b>Early time WAG</b>	<b>12</b>	0.33	63810	5.7
<b>2</b>		<b>6</b>	0.32	63980	5.5
<b>3</b>		<b>3</b>	0.34	67780	6.0
<b>4</b>		<b>SWAG</b>	0.37	72910	6.4
<b>5</b>	<b>Late time WAG</b>	<b>12</b>	0.34	65830	5.8
<b>6</b>		<b>6</b>	0.35	68040	5.8
<b>7</b>		<b>3</b>	0.37	72420	6.0
<b>8</b>		<b>SWAG</b>	0.38	74570	6.2
<b>9</b>	<b>Lifetime WAG</b>	<b>12</b>	0.47	92490	6.8
<b>10</b>		<b>6</b>	0.53	103560	6.9
<b>11</b>		<b>6 (limited)</b>	0.37	72570	5.2
<b>12</b>		<b>3</b>	0.55	107650	6.9
<b>13</b>		<b>3 (limited)</b>	0.39	76730	5.3
<b>14</b>		<b>SWAG</b>	0.56	112540	7.3
<b>15</b>		<b>SWAG (limited)</b>	0.39	76610	5.5
<b>16</b>		<b>Lifetime changing completion</b>	<b>case 10</b>	0.64	127910
<b>17</b>	<b>case 11</b>		0.46	89660	6.4
<b>18</b>	<b>case 12</b>		0.68	133720	7.4
<b>19</b>	<b>case 13</b>		0.49	96620	6.7

## APPENDIX B. Figures

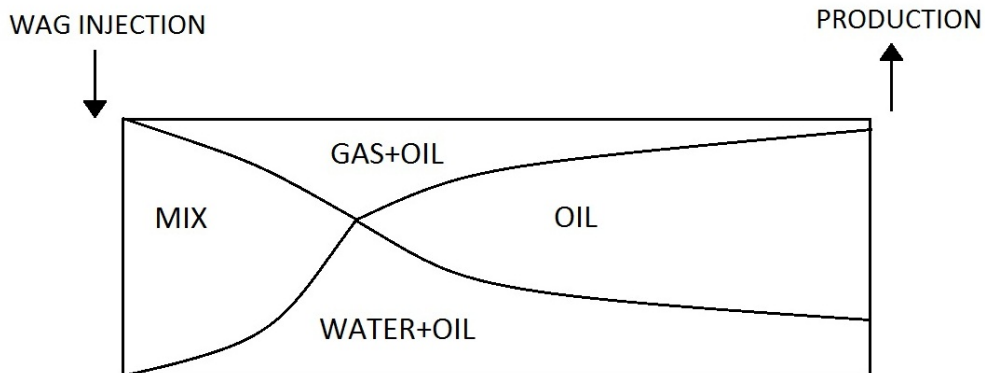


Figure 1.1 Flow zones during WAG injection

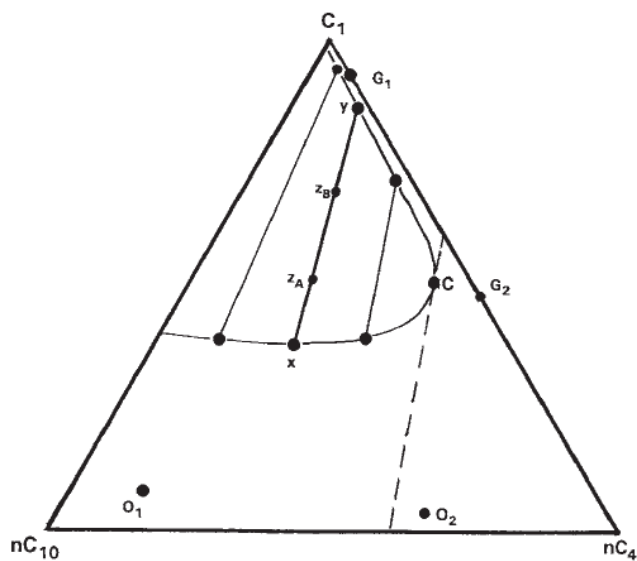


Figure 1.2 Ternary composition diagram for C1/n-C4/n-C10 system at 280 F<sup>0</sup> and 2000 psia.  
(Whitson & Brule Phase Behavior SPE monograph 2000).

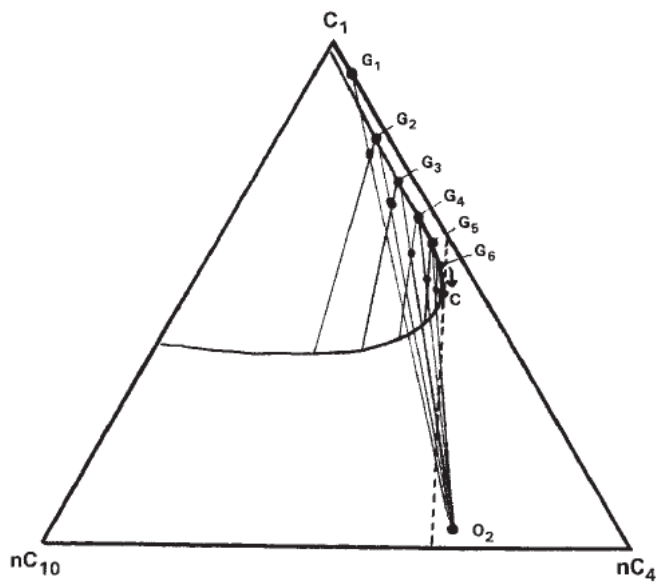


Figure 1.3 Path of developed miscibility by vaporizing-gas miscible drive process for C1/n-C4/n-C10 system (Whitson & Brule Phase Behavior SPE monograph 2000)

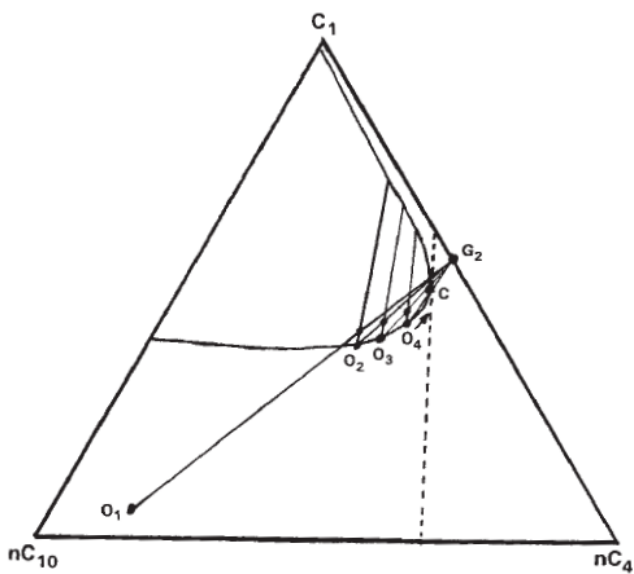


Figure 1.4 Path of developed miscibility by enriched-gas miscible drive process for C1/n-C4/n-C10 system (Whitson & Brule Phase Behavior SPE monograph 2000)

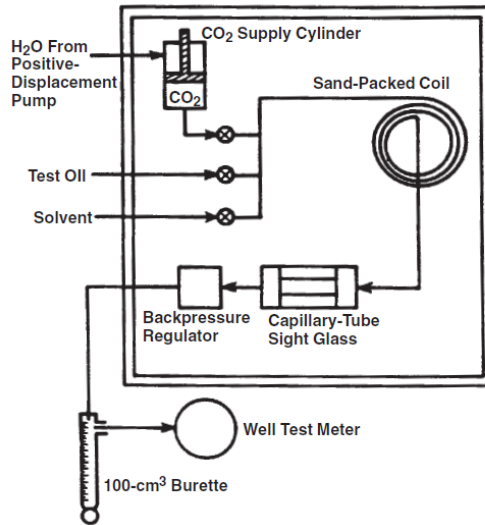


Figure 1.5 Schematic of slim tube apparatus. (Whitson & Brule Phase Behavior SPE monograph 2000)

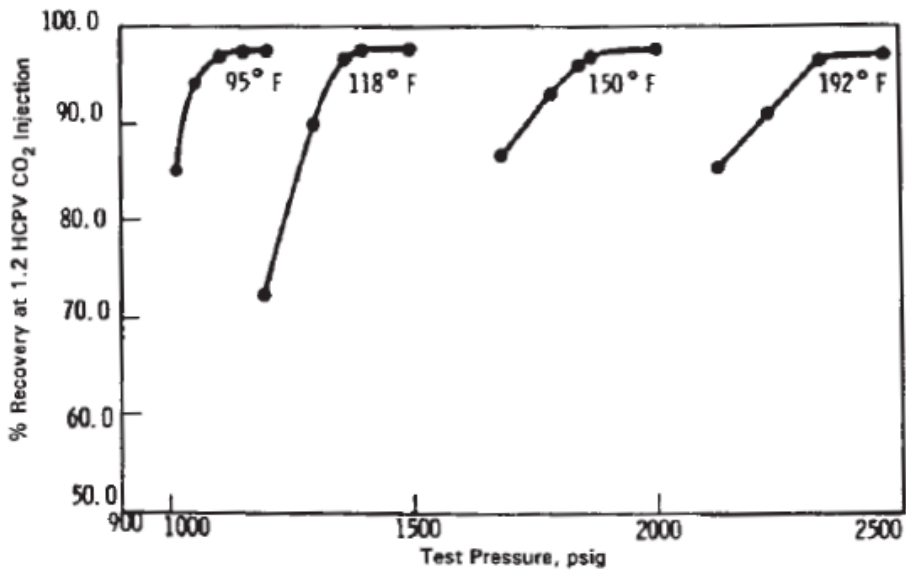


Figure 1.6 Slim tube experimental results for CO<sub>2</sub> displacement of west Texas oil at different temperatures. (Whitson & Brule Phase Behavior SPE monograph 2000)

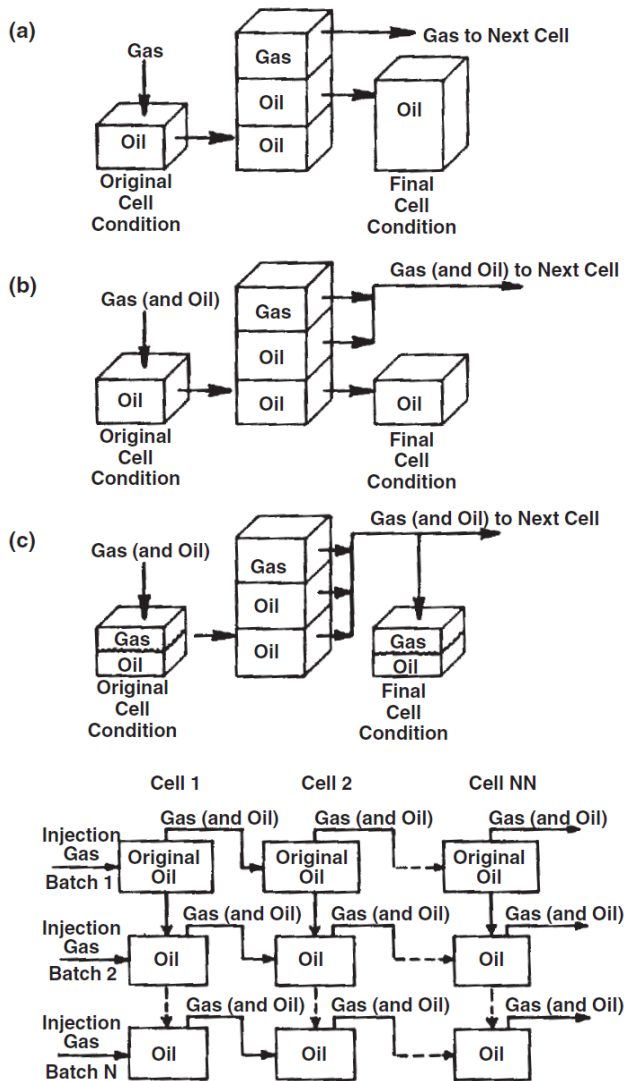


Figure 1.7 Schematic of multicell calculation method: (a) stagnant oil, (b) moving excess oil, (c) movement of phases according to phase mobilities. (Whitson & Brule Phase Behavior SPE monograph 2000)

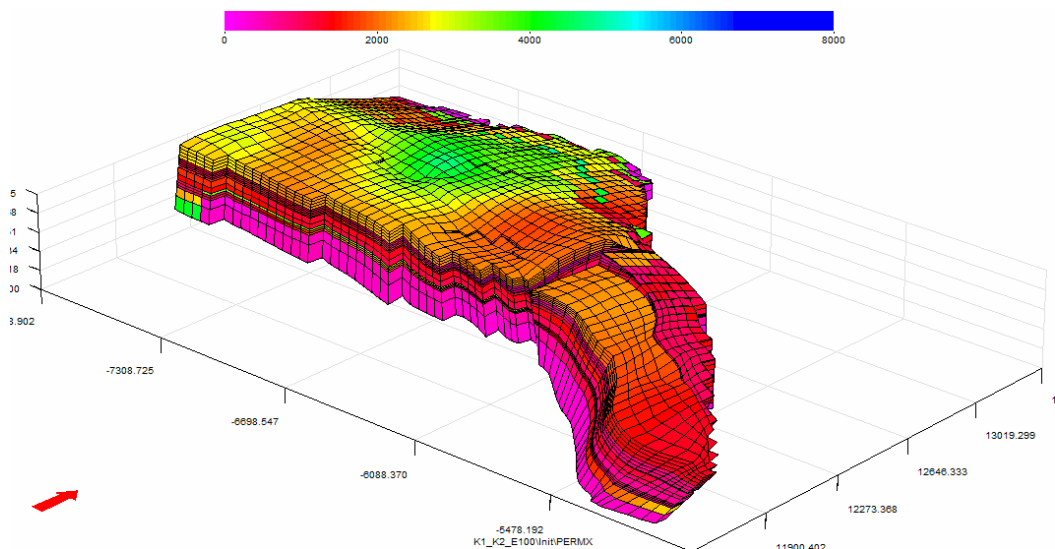


Figure 2.1 Distribution of PERMX parameter (PERMX=PERMY)

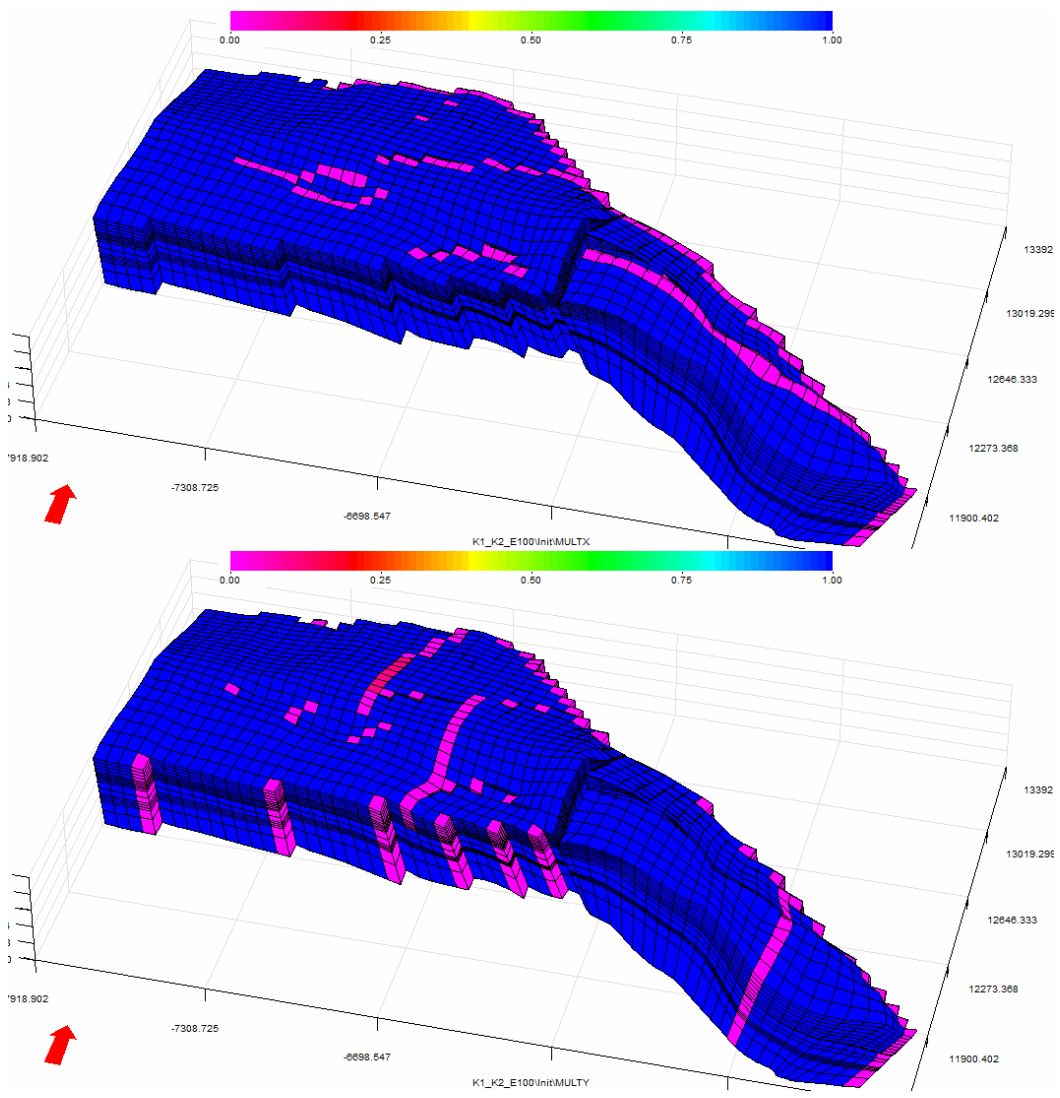


Figure 2.2 Faults of the reservoir

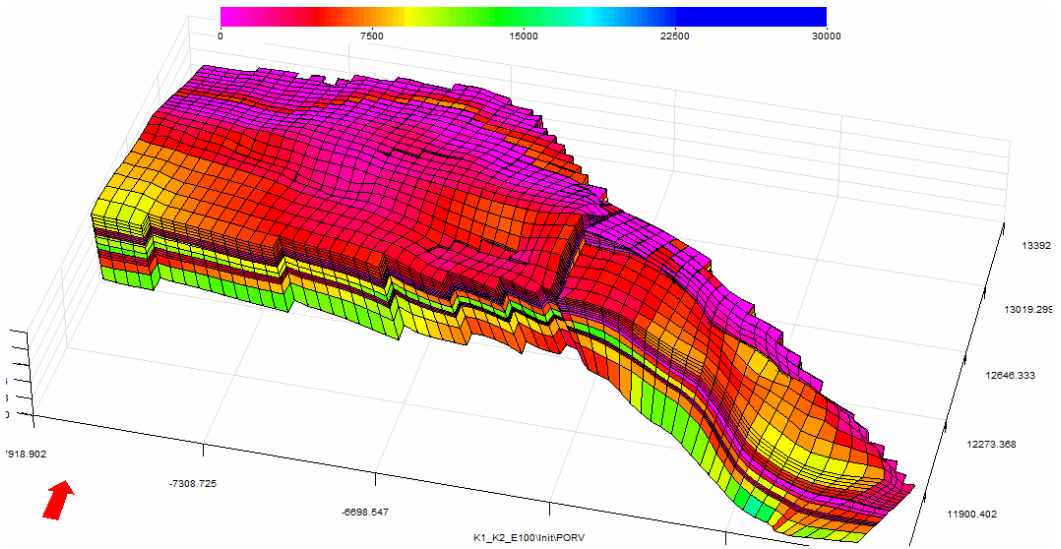


Figure 2.3 Pore volume distribution

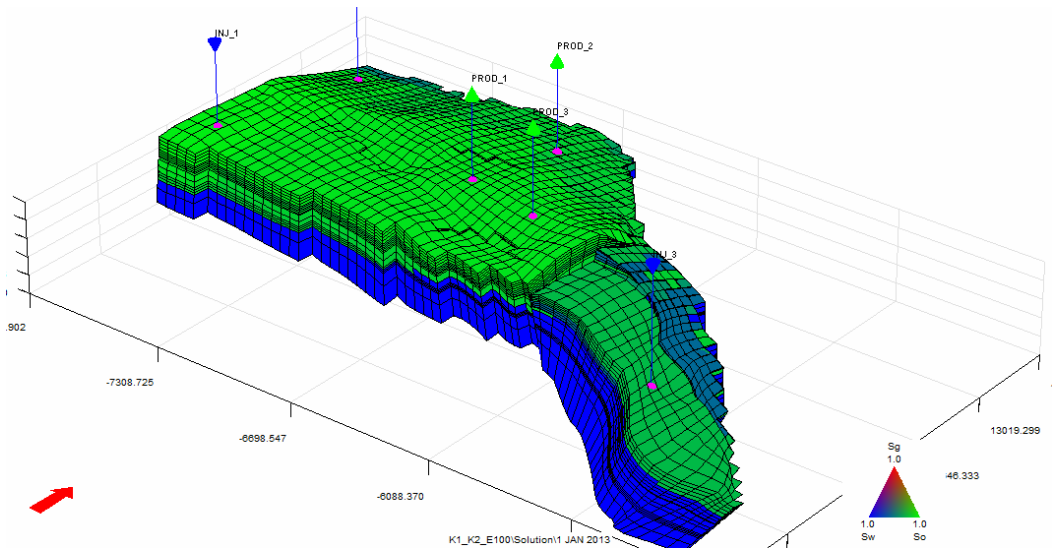
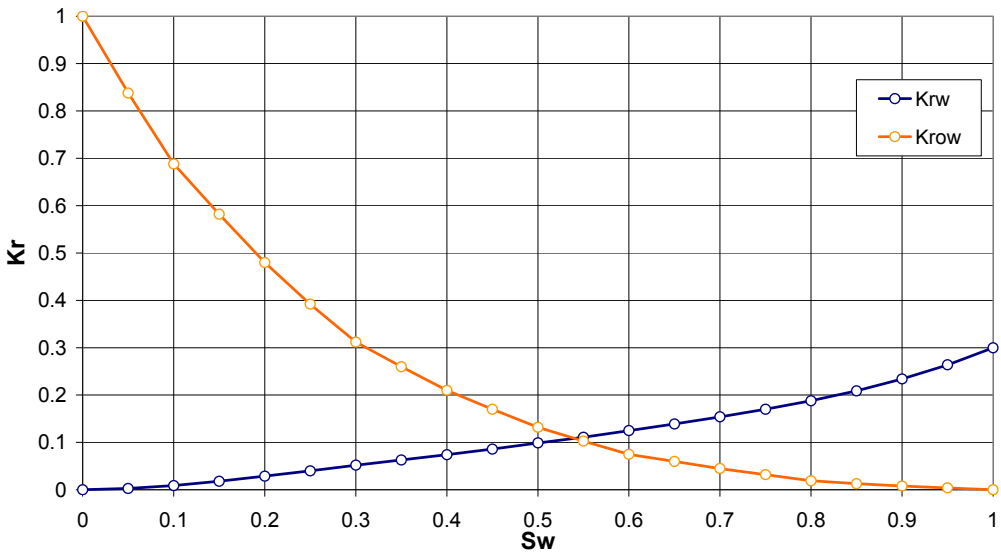


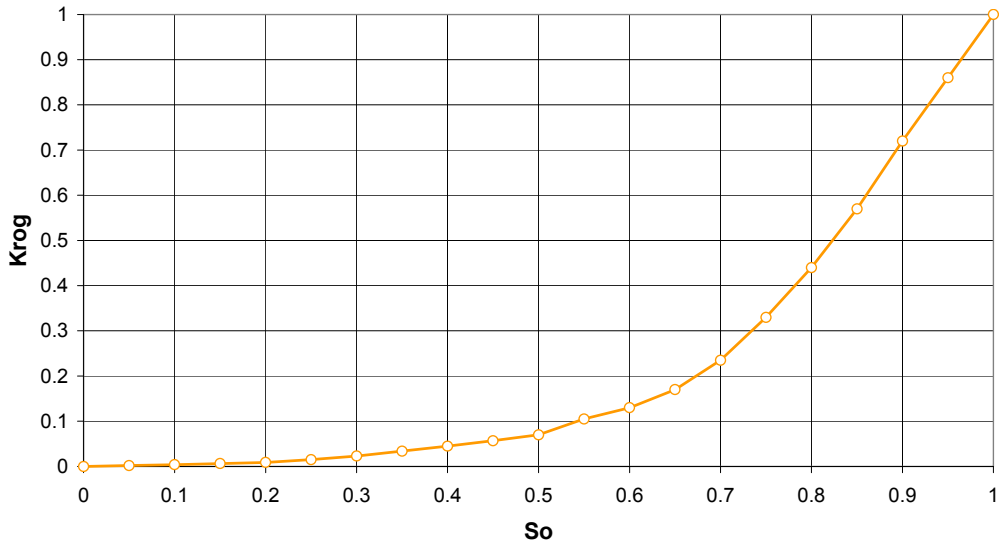
Figure 2.4 Initial saturation of fluids in the reservoir



Water - Oil Relative Permeability



Oil relative permeability for 3 phase case (with connate water)



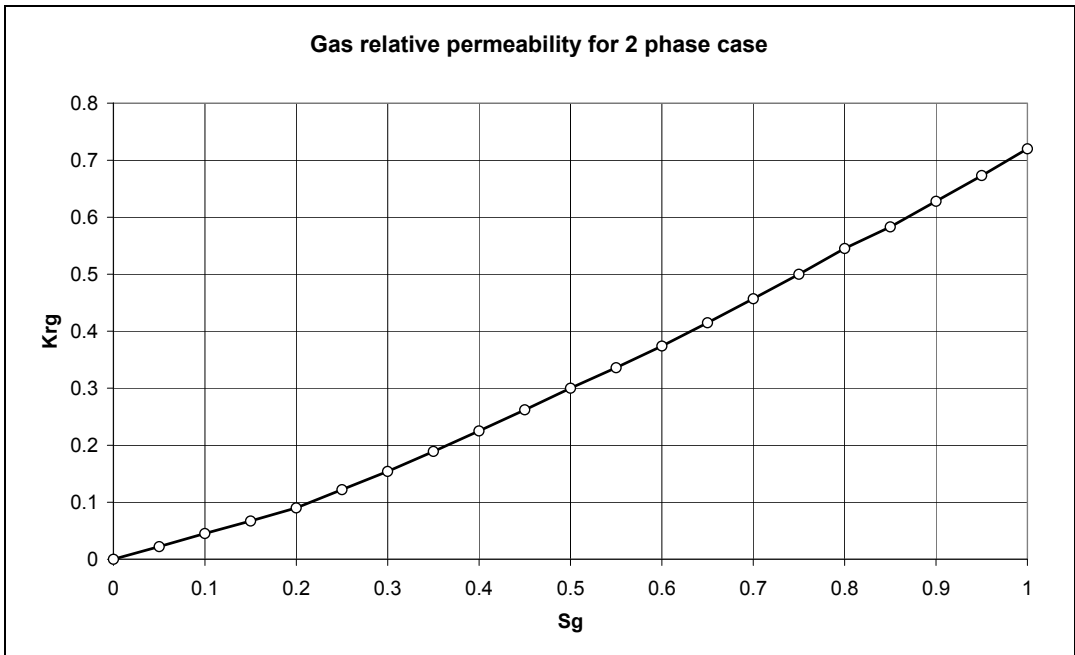


Figure 2.5 Relative permeability curves

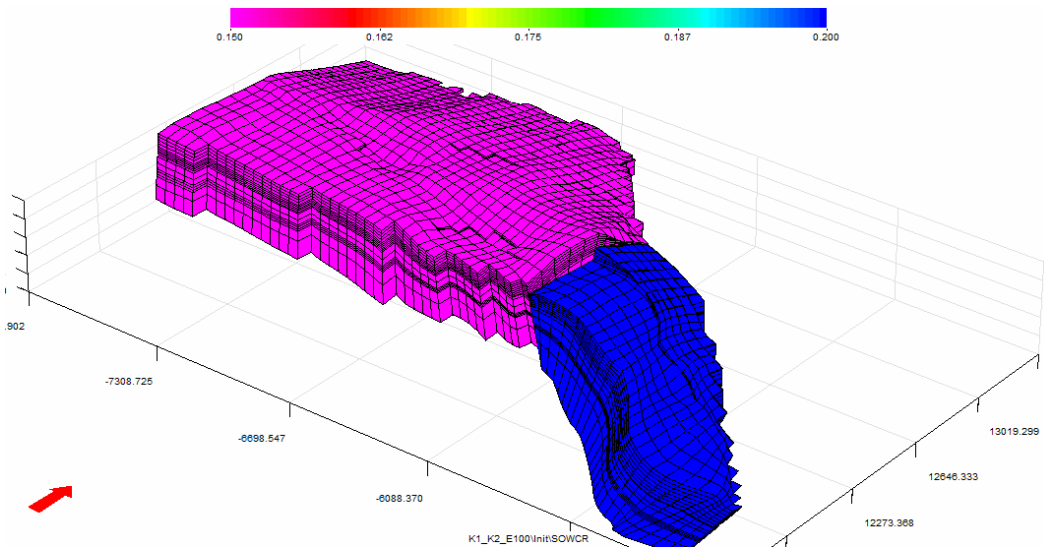


Figure 2.6 Critical oil saturation for water-oil case

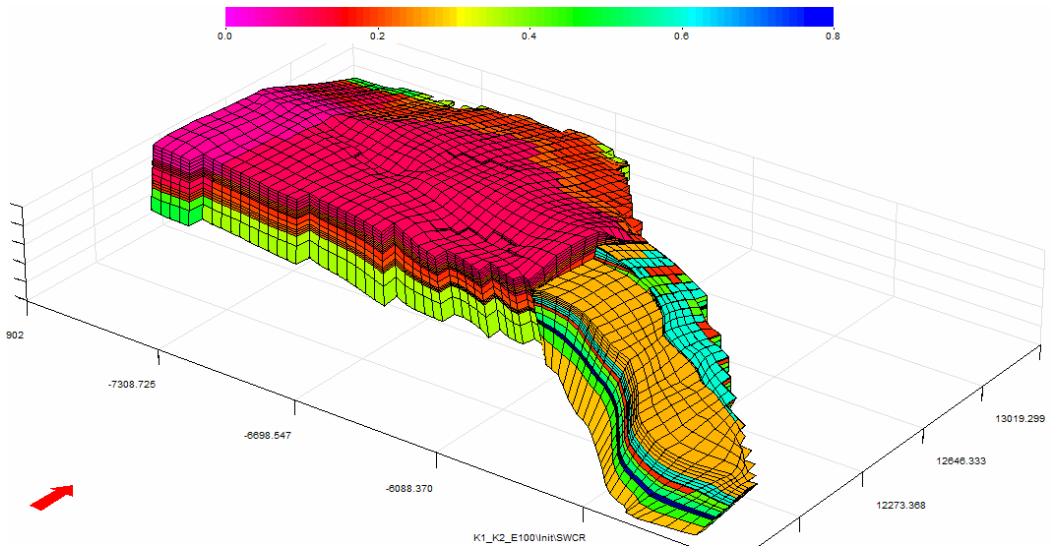


Figure 2.7 Critical water saturation

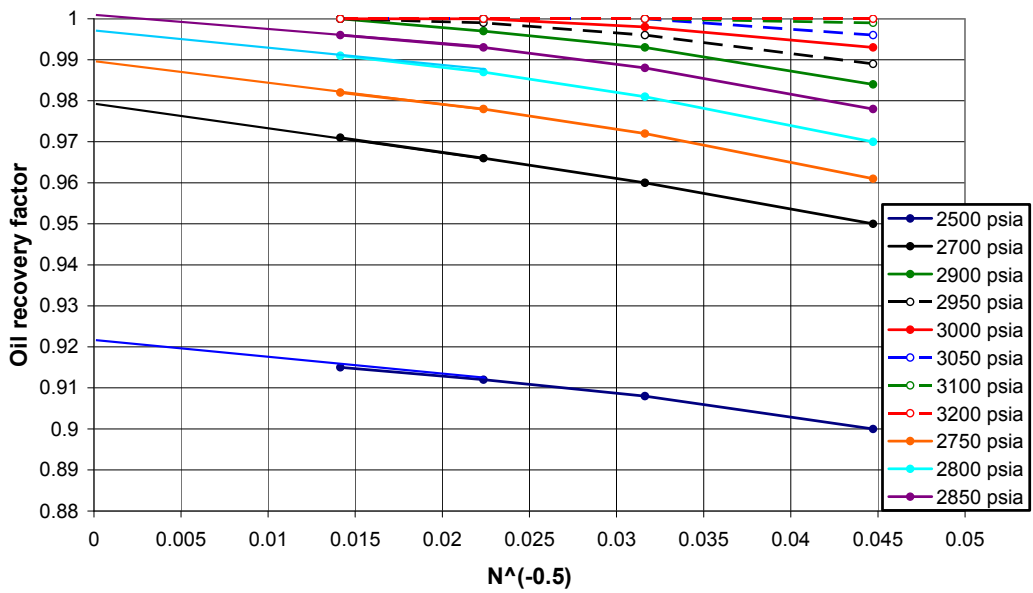


Figure 3.1 Recovery factor for slim tube simulations grouped according to pressure.

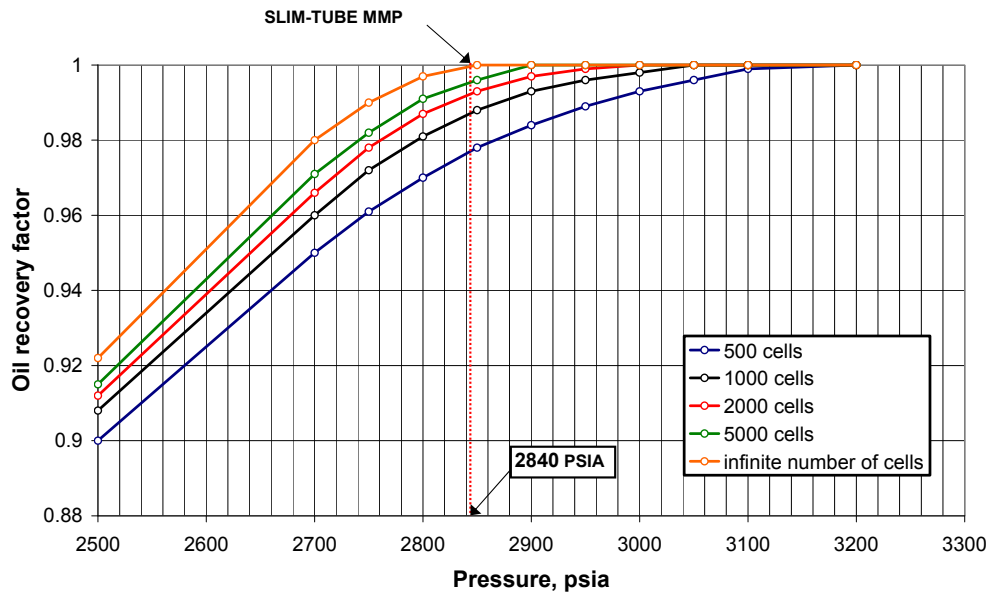


Figure 3.2 Recovery factor for slim tube simulations with different number of cells N.

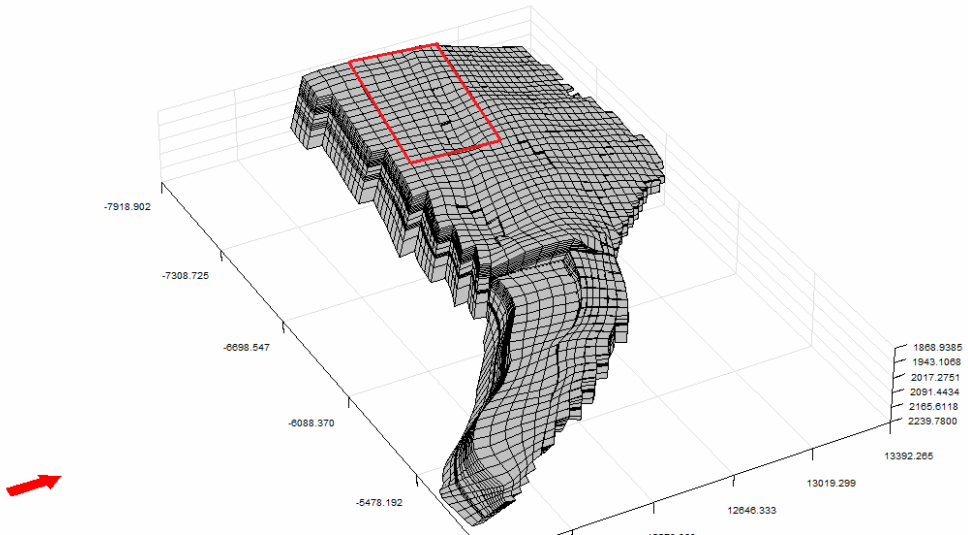


Figure 4.1 Segment model place (with red) on the field scale model

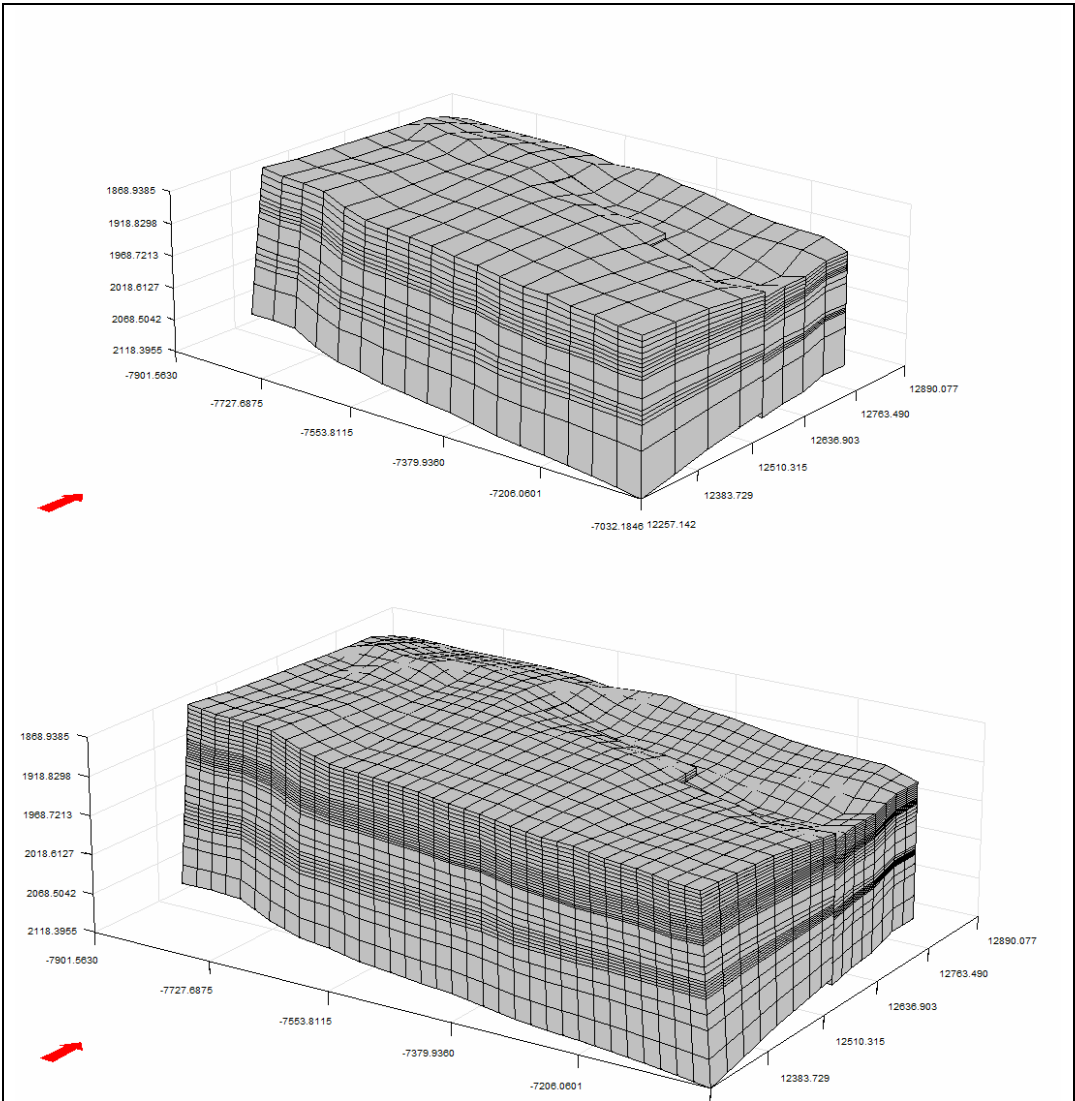


Figure 4.2 Coarse grid segment model (upper snapshot) and fine grid segment model (lower snapshot)

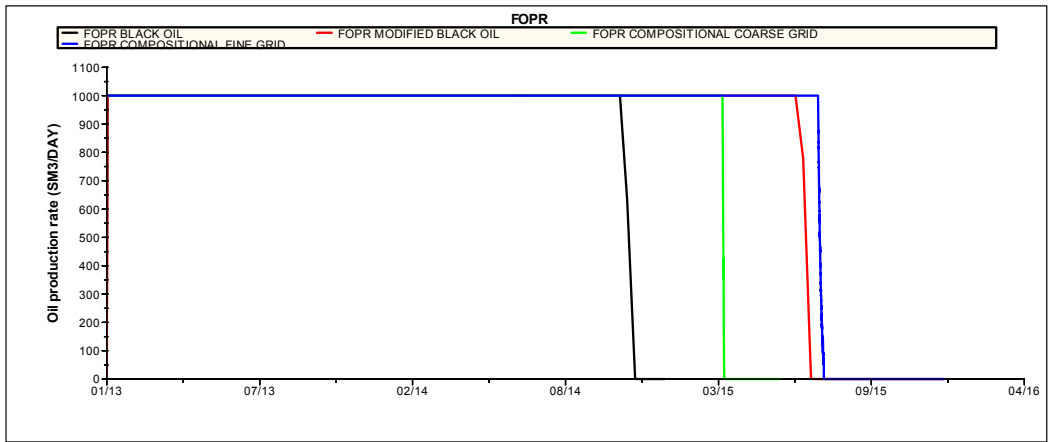


Figure 4.3 Oil production rate for depletion case

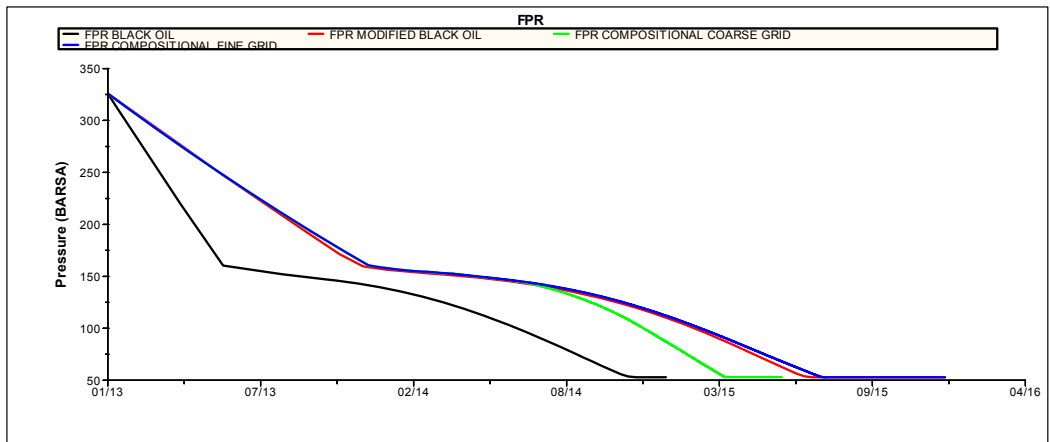


Figure 4.4 Field pressure for depletion case

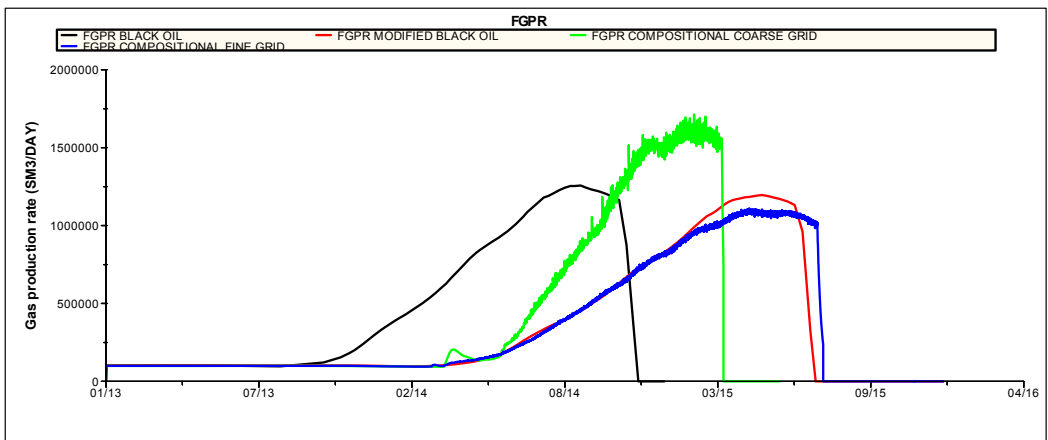


Figure 4.5 Field gas production rate for depletion case

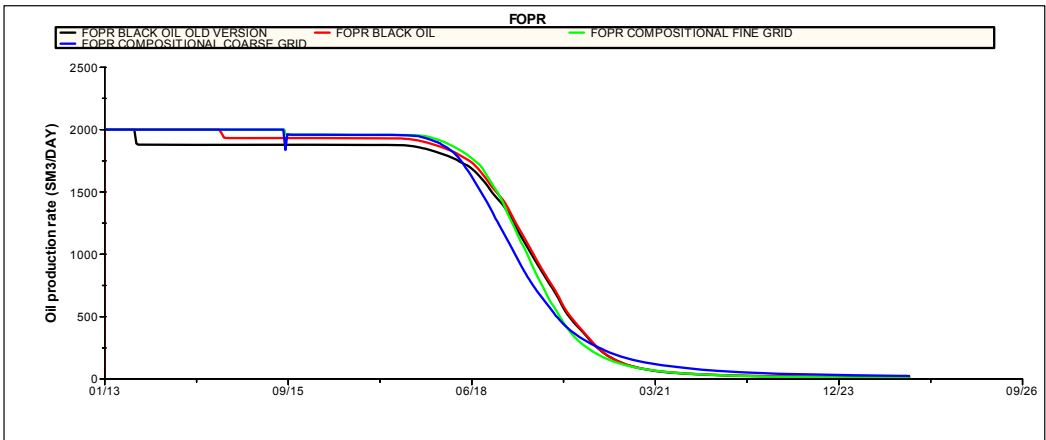


Figure 4.6 Oil production rate for water injection case.

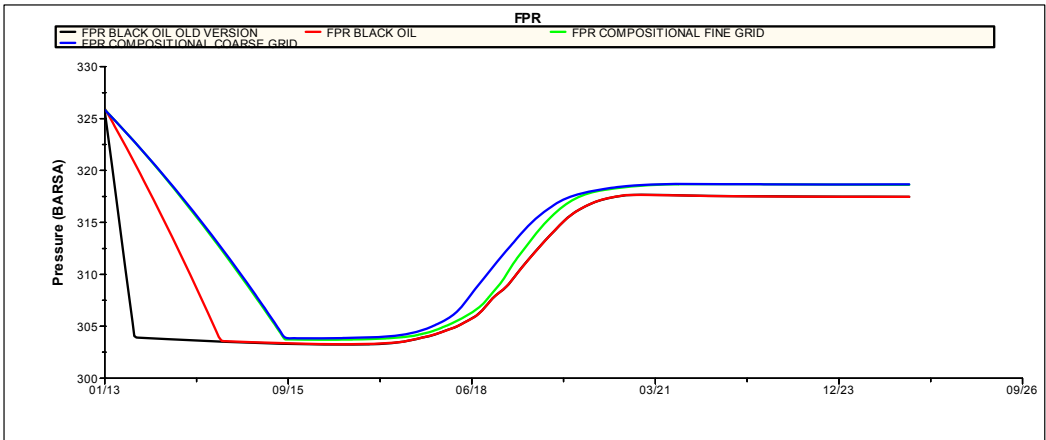


Figure 4.7 Pressure for water injection case

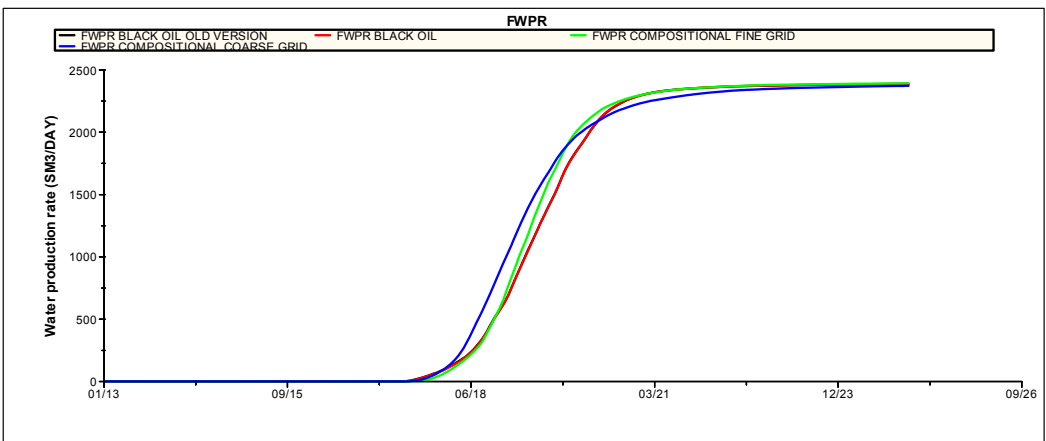


Figure 4.8 Water production rate for water injection case



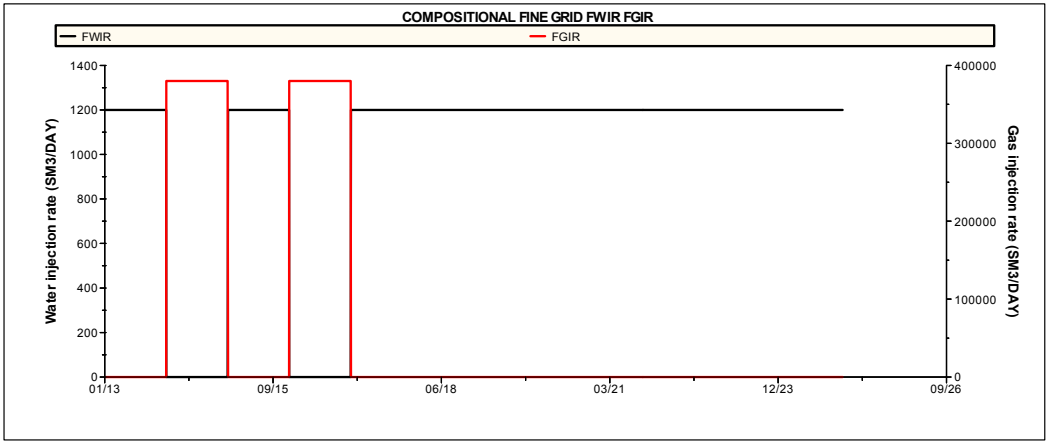


Figure 4.9 Gas and water injection rates for WAG scenario

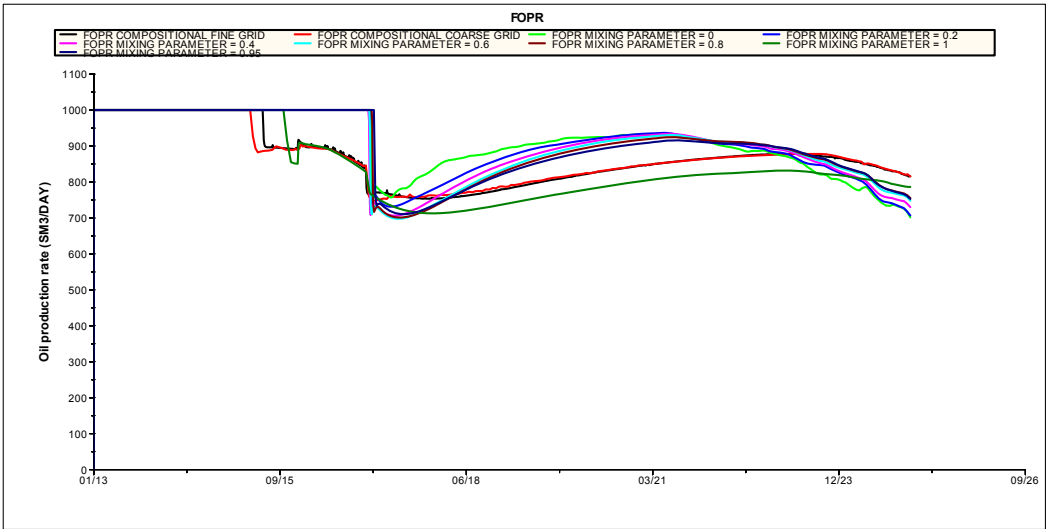


Figure 4.10 Oil production rate for WAG scenario

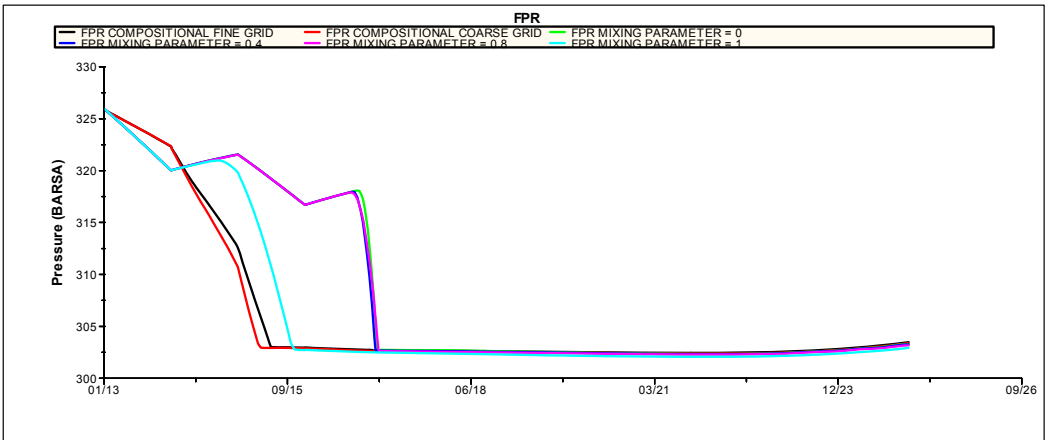


Figure 4.11 Pressure for WAG scenario

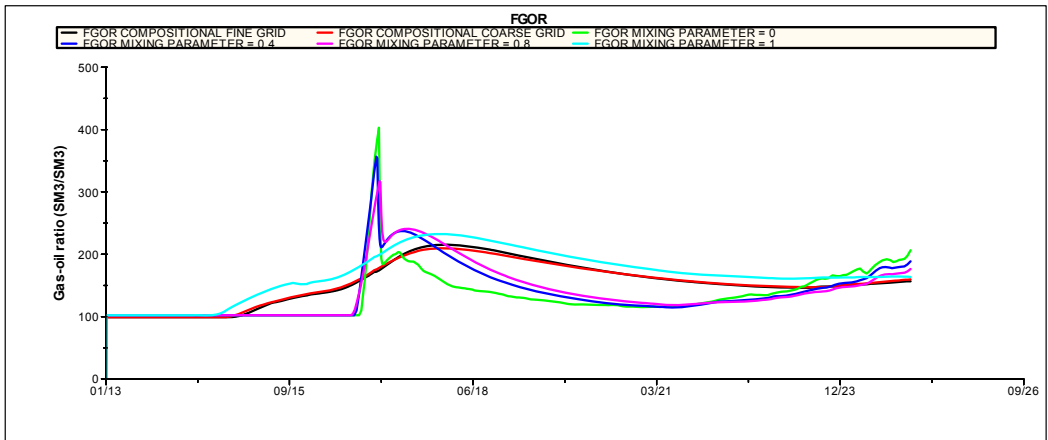


Figure 4.12 Gas-oil ratio for WAG scenario

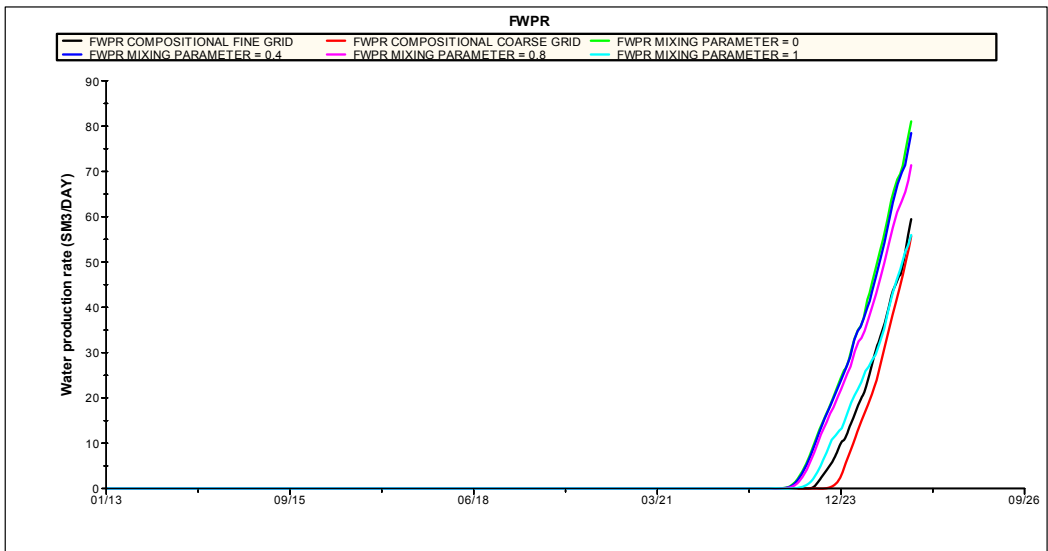


Figure 4.13 Water production rate for WAG scenario

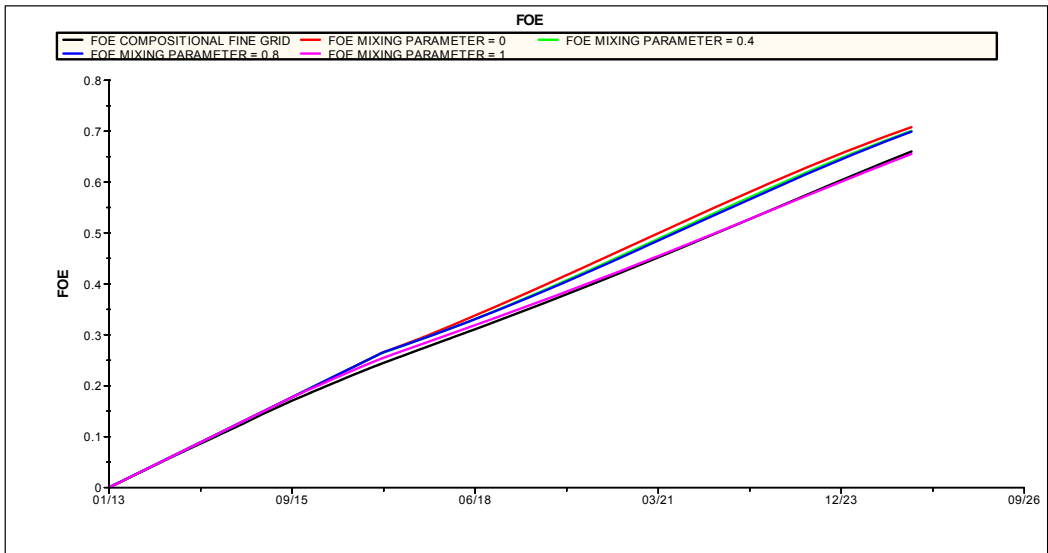


Figure 4.14 Recovery of oil for WAG scenario

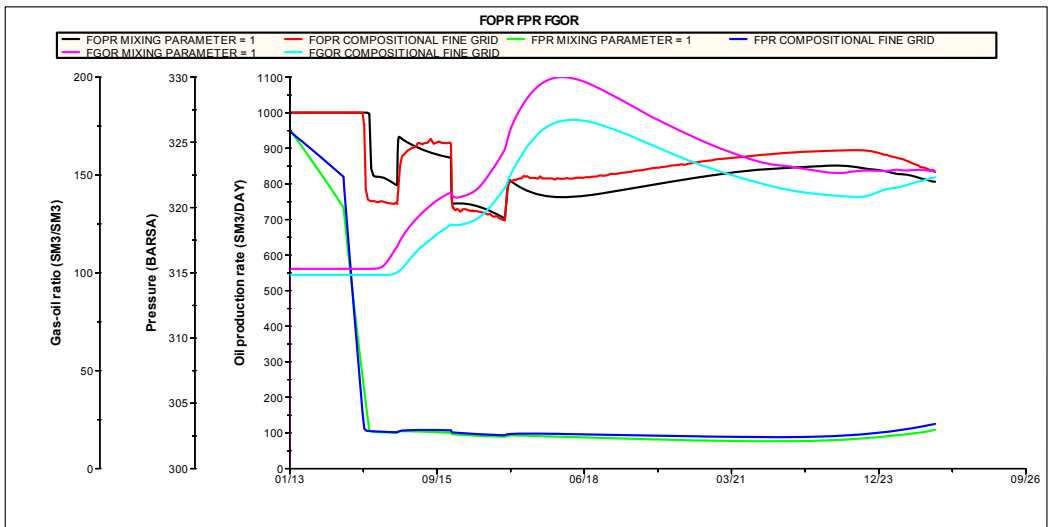


Figure 4. 15 WAG scenario with gas injection rate set to 300000 Sm<sup>3</sup>/d

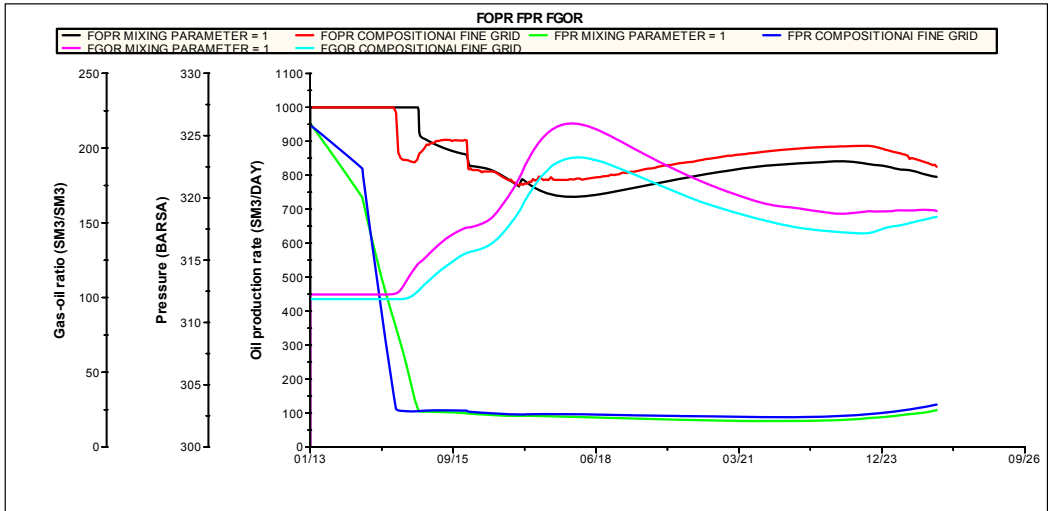


Figure 4.16 WAG scenario with gas injection rate set to 340000 Sm<sup>3</sup>/d

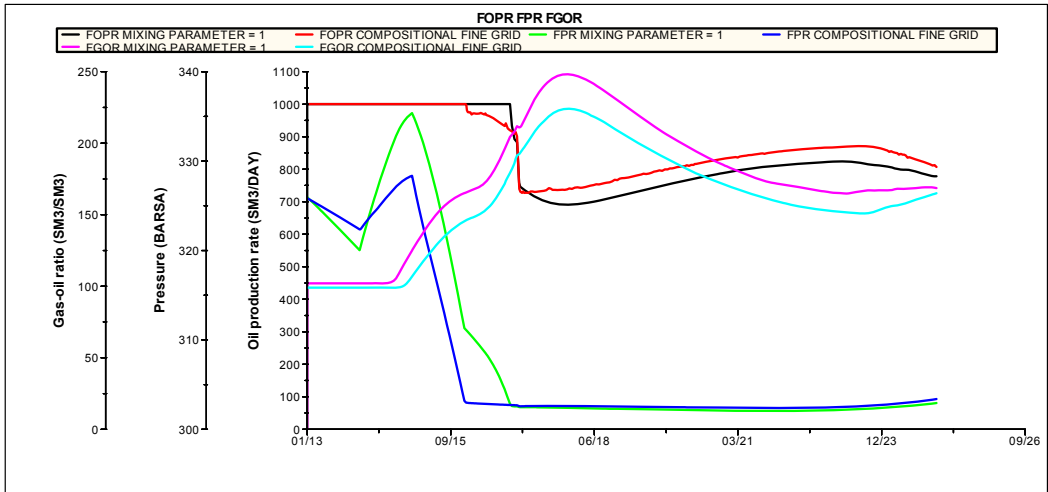


Figure 4.17 WAG scenario with gas injection rate set to 420000 Sm<sup>3</sup>/d

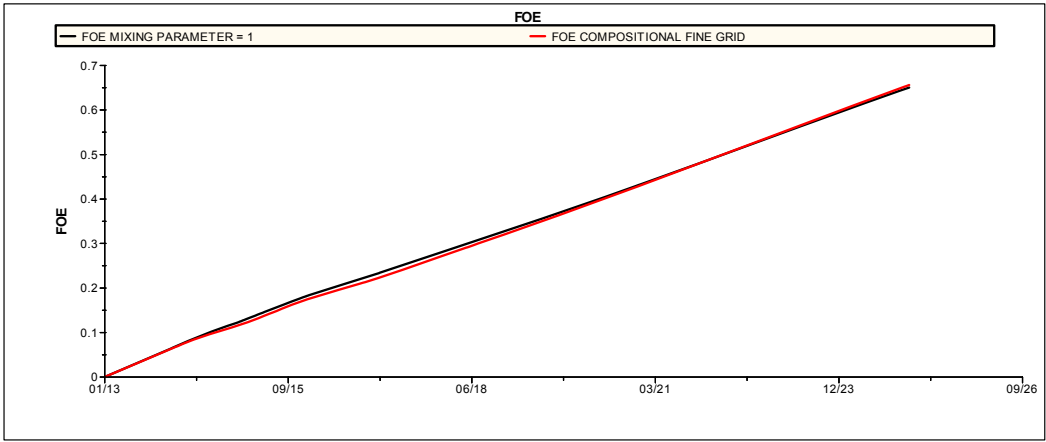


Figure 4.18 Oil recovery for WAG scenario with gas injection rate set to 300000 Sm<sup>3</sup>/d

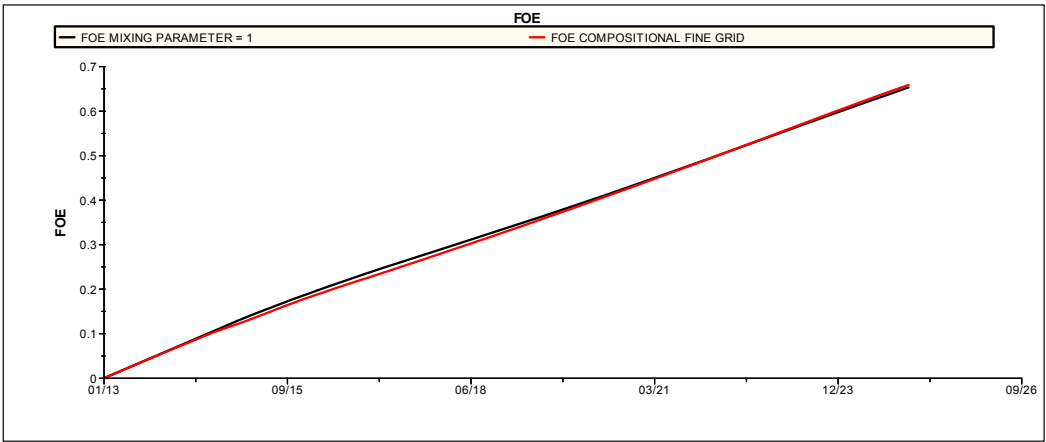


Figure 4.19 Oil recovery for WAG scenario with gas injection rate set to 340000 Sm<sup>3</sup>/d

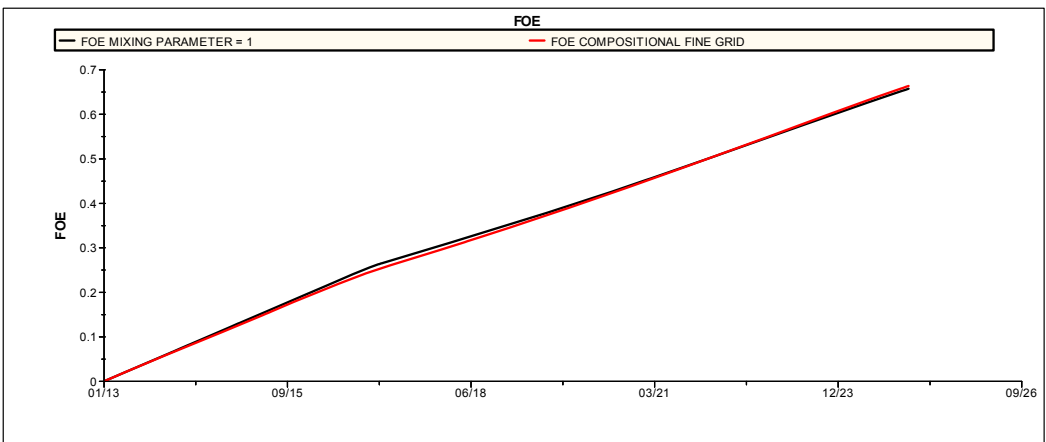


Figure 4.20 Oil recovery for WAG scenario with gas injection rate set to 420000 Sm<sup>3</sup>/d

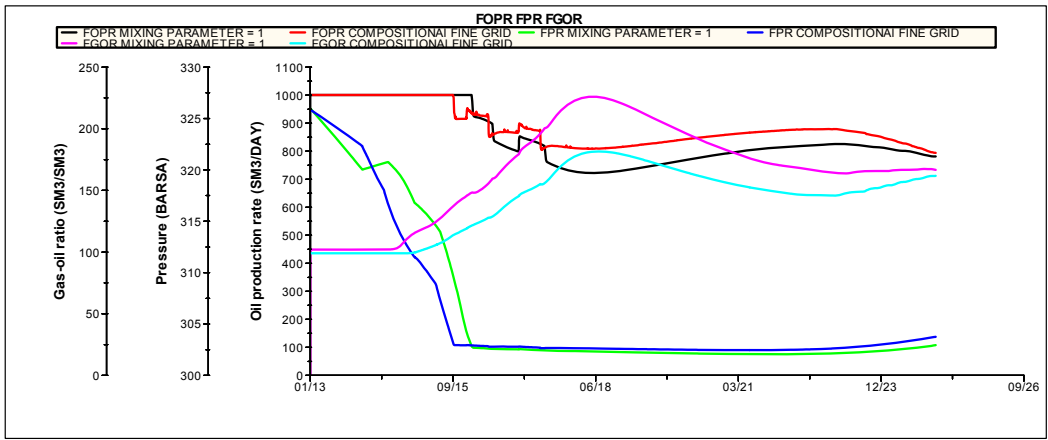


Figure 4.21 WAG scenario with half-cycle set to 6 months.

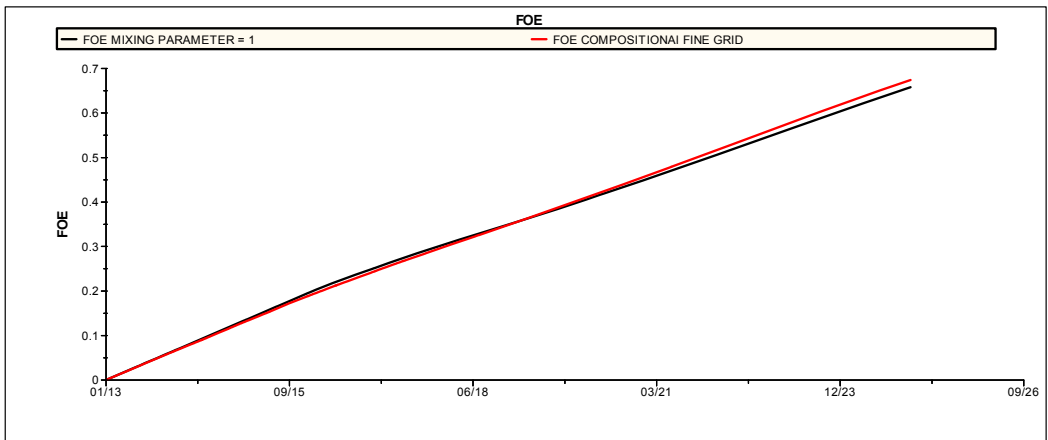


Figure 4.22 Recovery factor for WAG scenario with half-cycle set to 6 months.

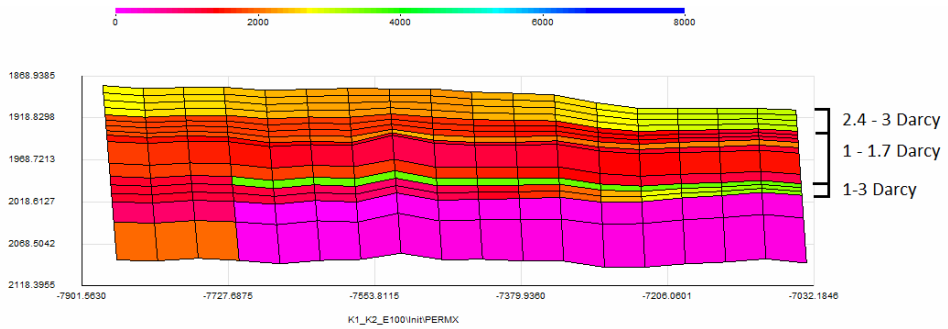


Figure 4.23 Horizontal permeability in cross section.

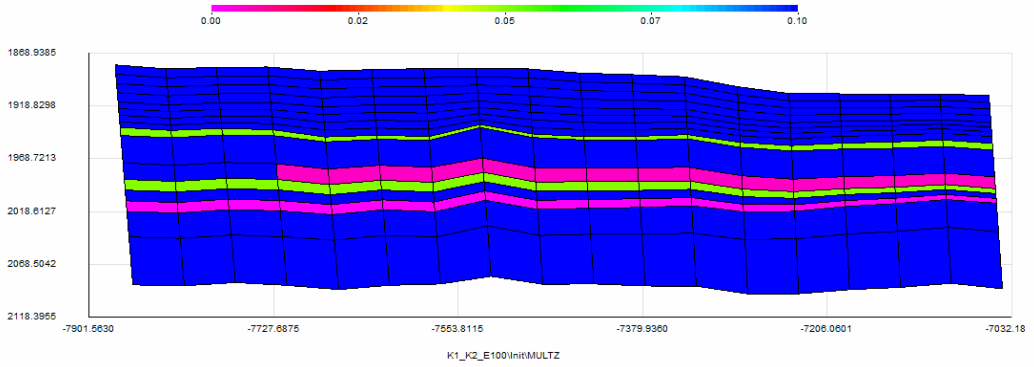


Figure 4.24 MULTZ value distribution in cross section.

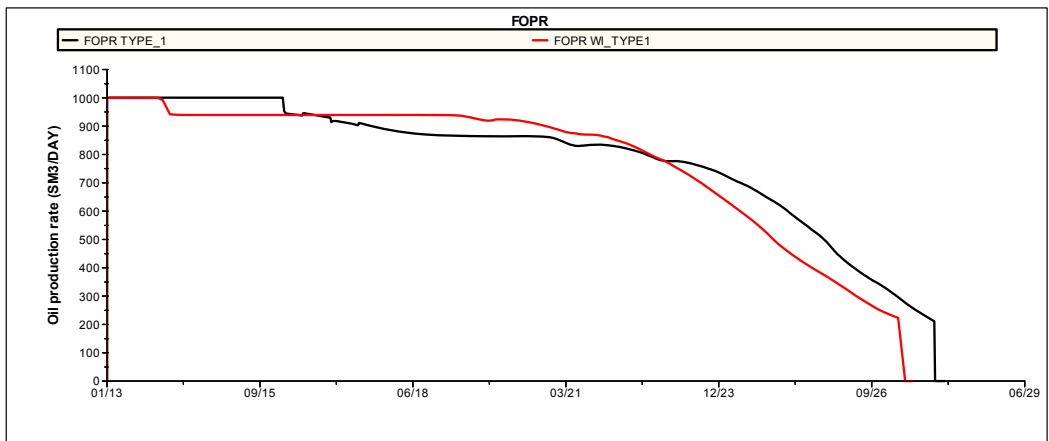


Figure 4.25 Oil production rate for type 1 completion

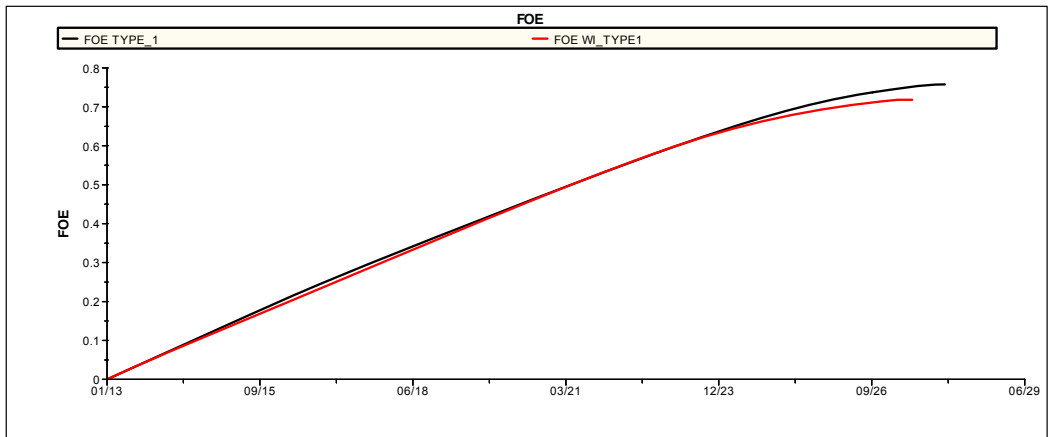


Figure 4.26 Oil recovery for type 1 completion

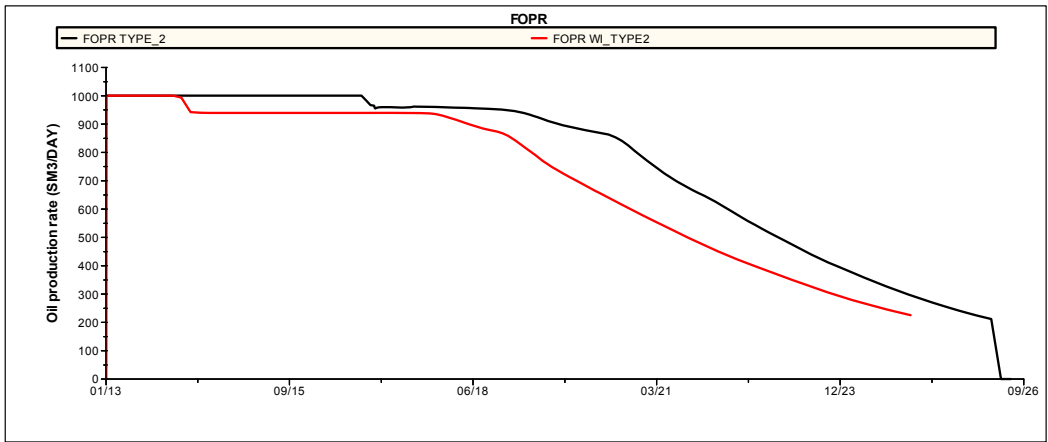


Figure 4.27 Oil production rate for type 2 completion

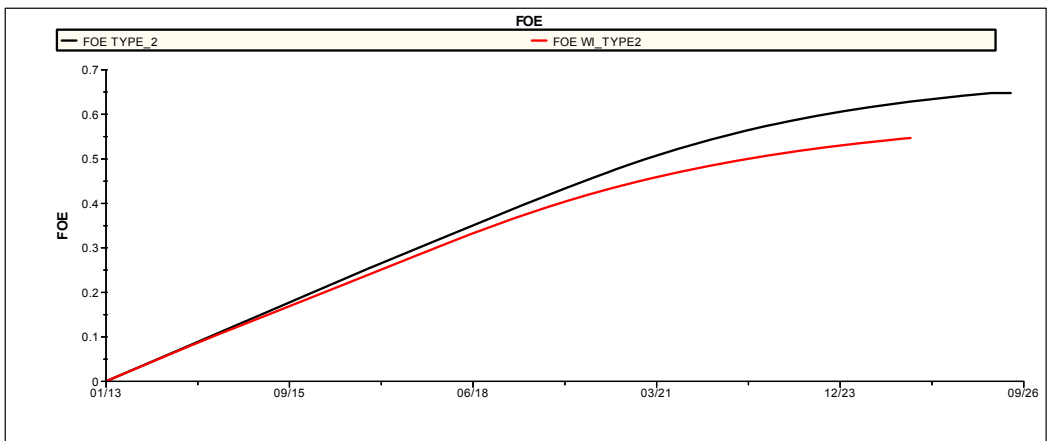


Figure 4.28 Oil recovery for type 2 completion

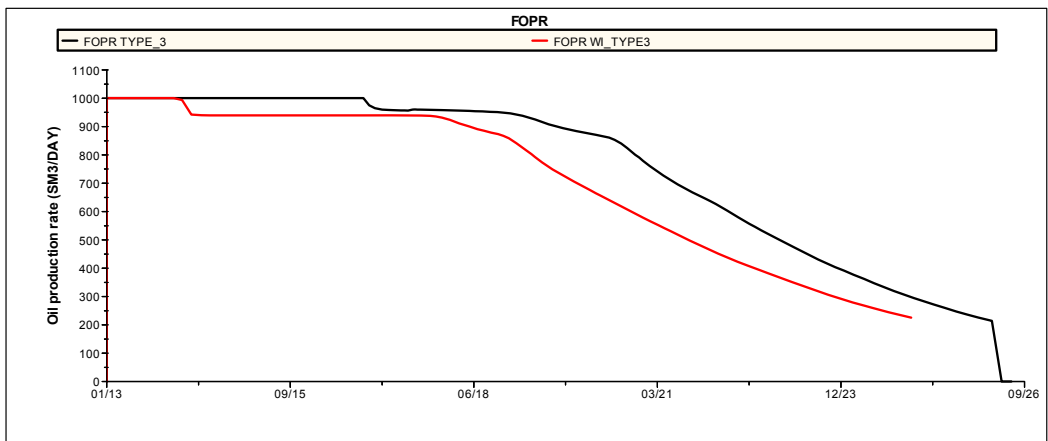


Figure 4.29 Oil production rate for type 3 completion



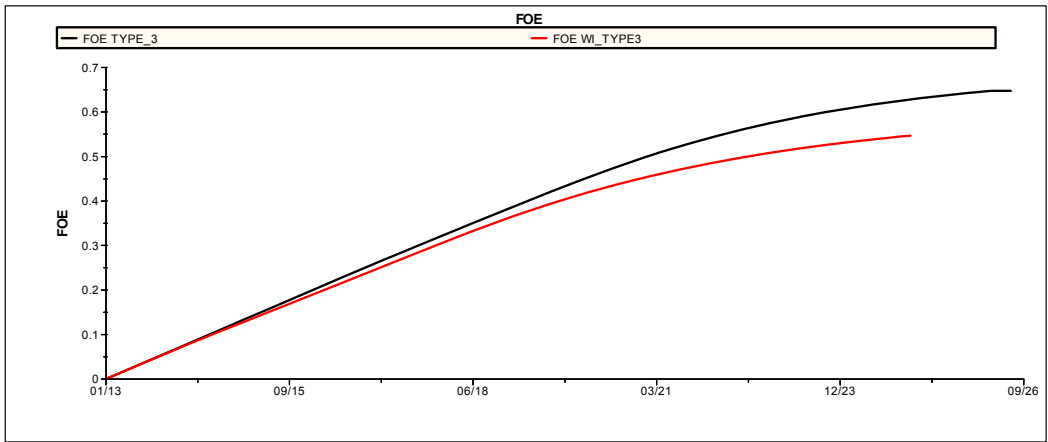


Figure 4.30 Oil recovery type 3 completion

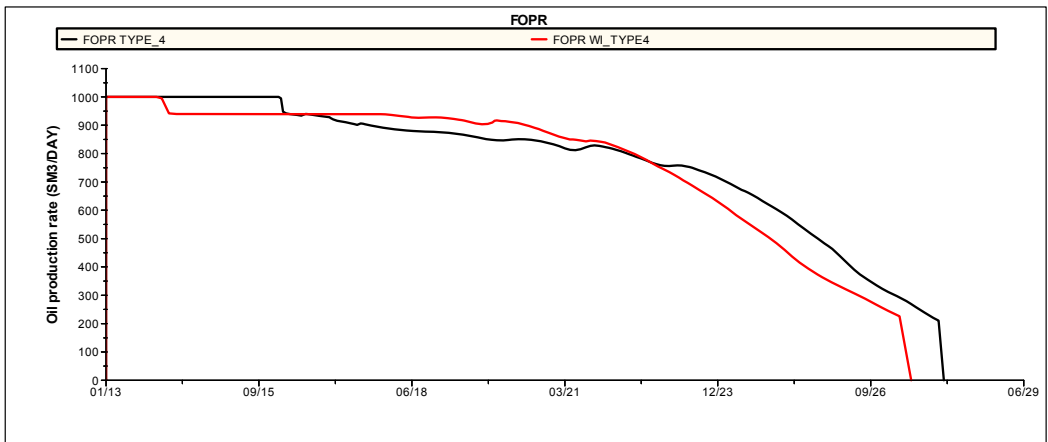


Figure 4.31 Oil production rate for type 4 completion

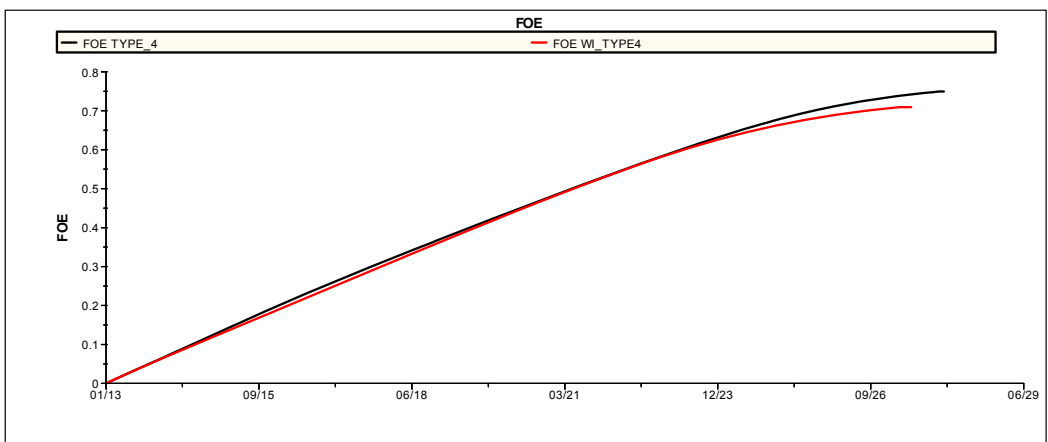


Figure 4.32 Oil recovery for type 4 completion

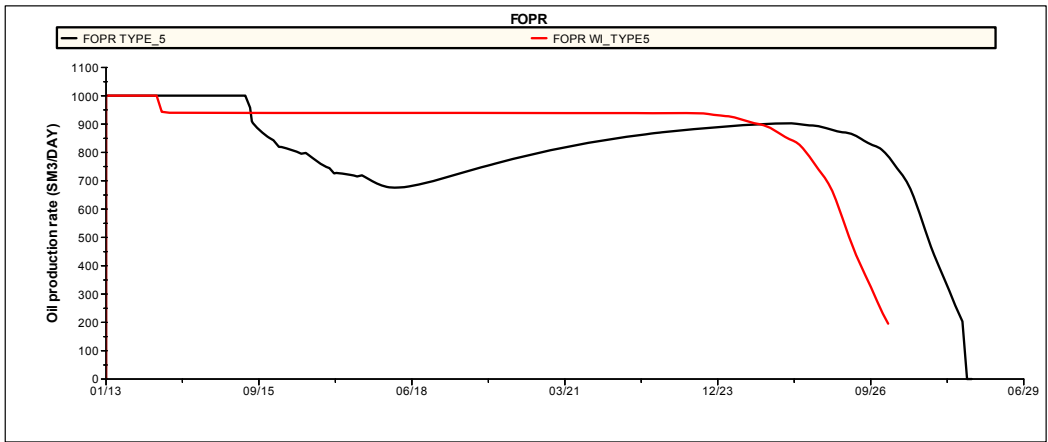


Figure 4.33 Oil production rate for type 5 completion

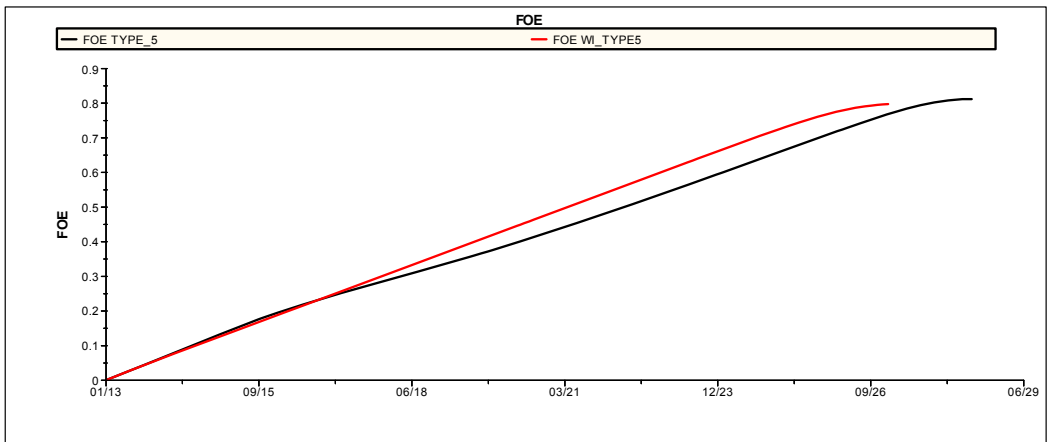


Figure 4.34 Oil recovery for type 5 completion

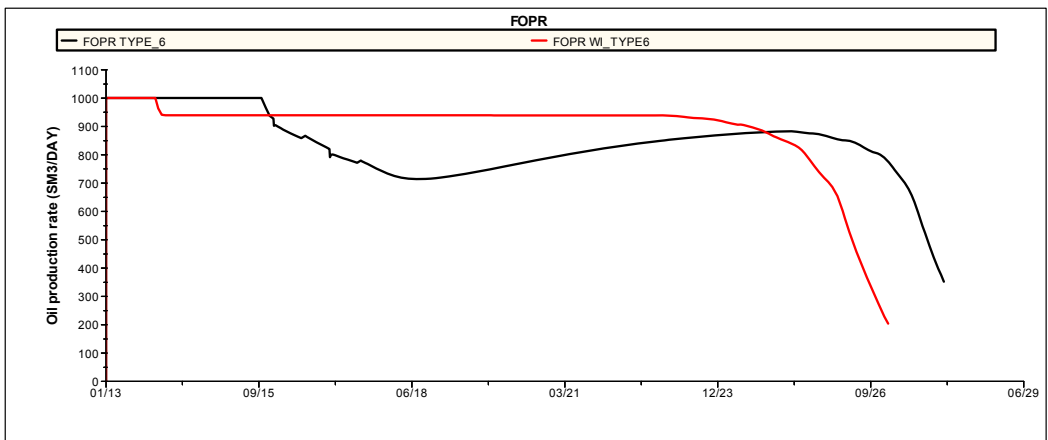


Figure 4.35 Oil production rate for type 6 completion

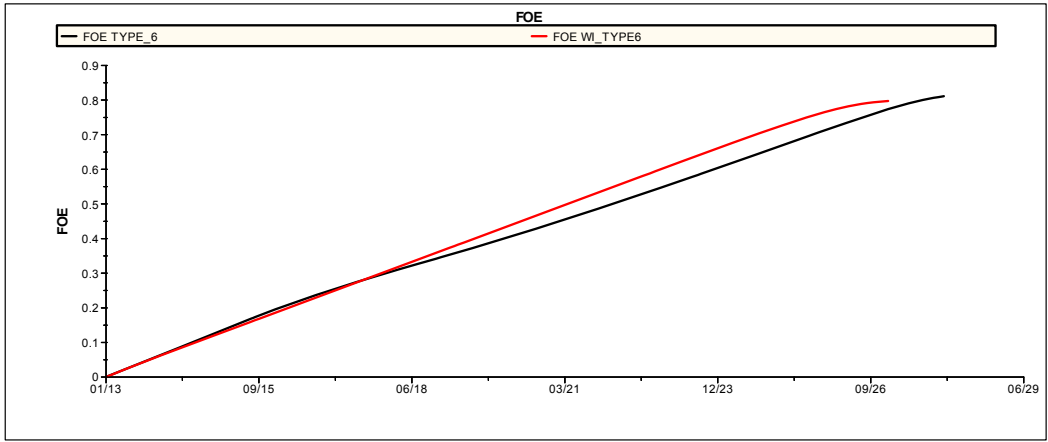


Figure 4.36 Oil recovery for type 6 completion

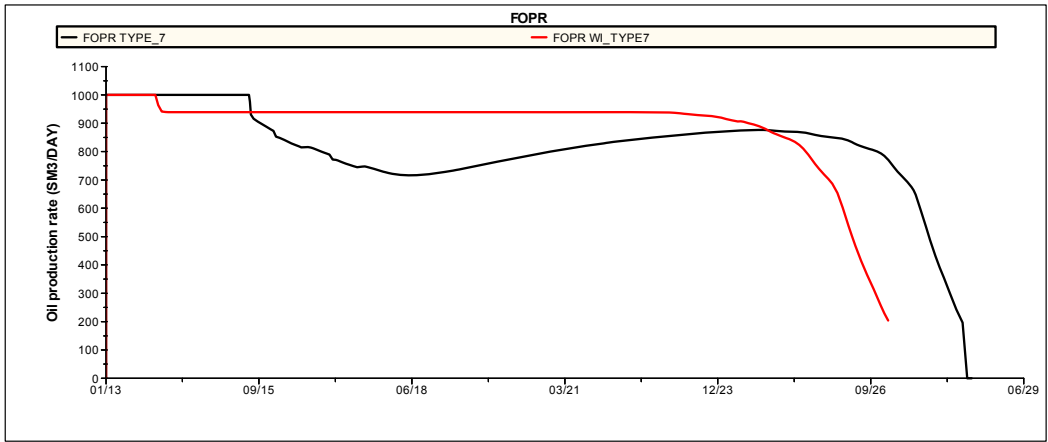


Figure 4.37 Oil production rate for type 7 completion

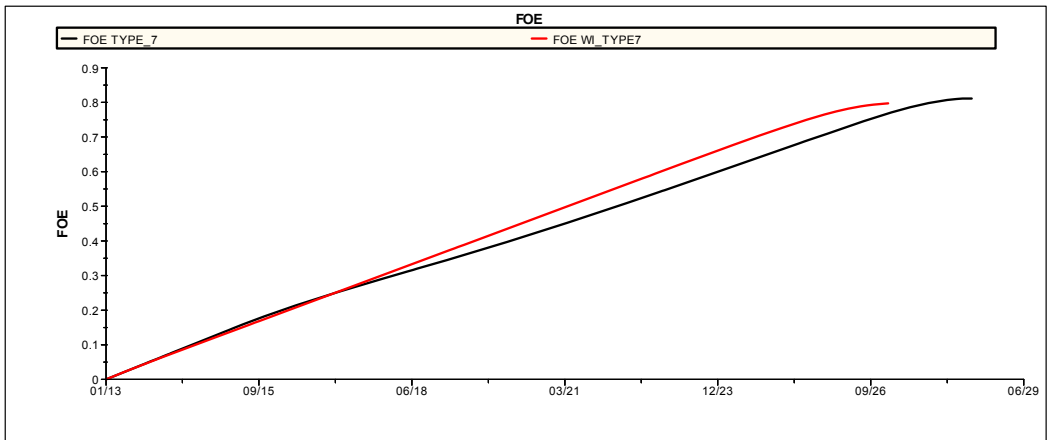


Figure 4.38 Oil recovery for type 7 completion

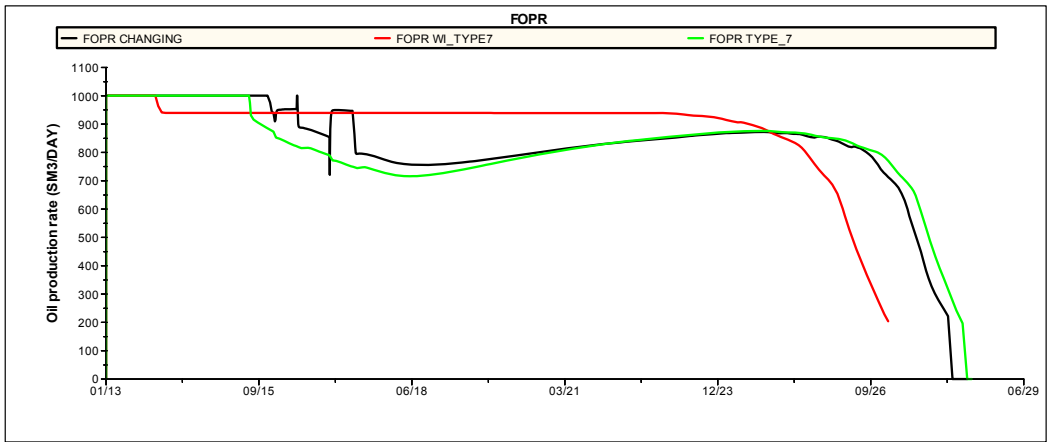


Figure 4.39 Oil production rate for type 8 changing completion. Compared with case for type 7.

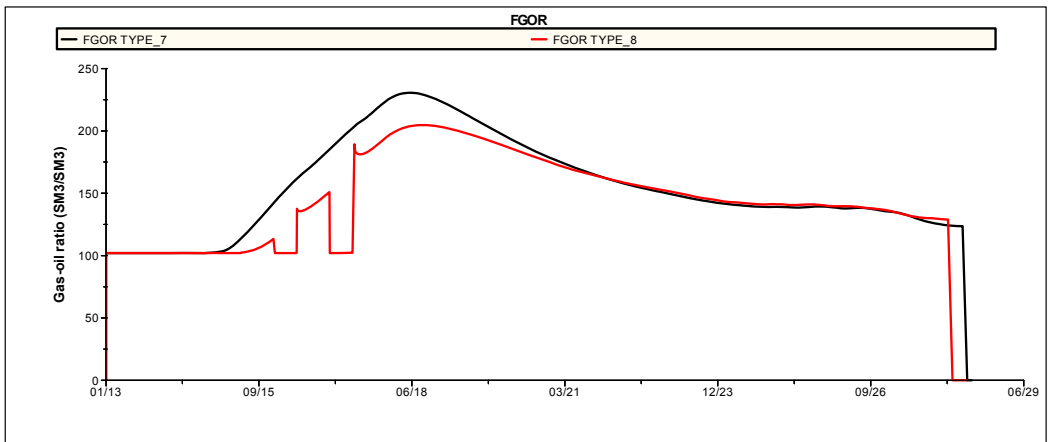


Figure 4.40 Gas-oil ratio for type 8 changing completion. Compared with case for type 7.

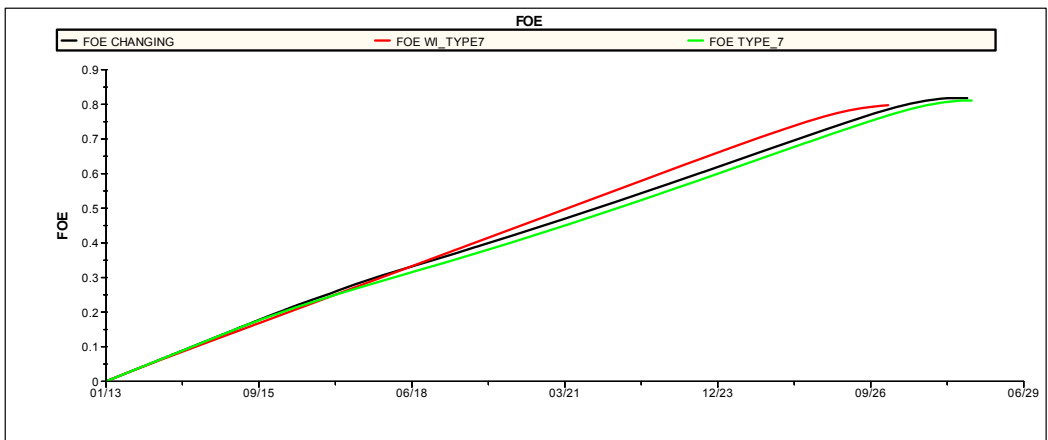


Figure 4.41 Oil recovery for type 8 changing completion. Compared with case for type 7.

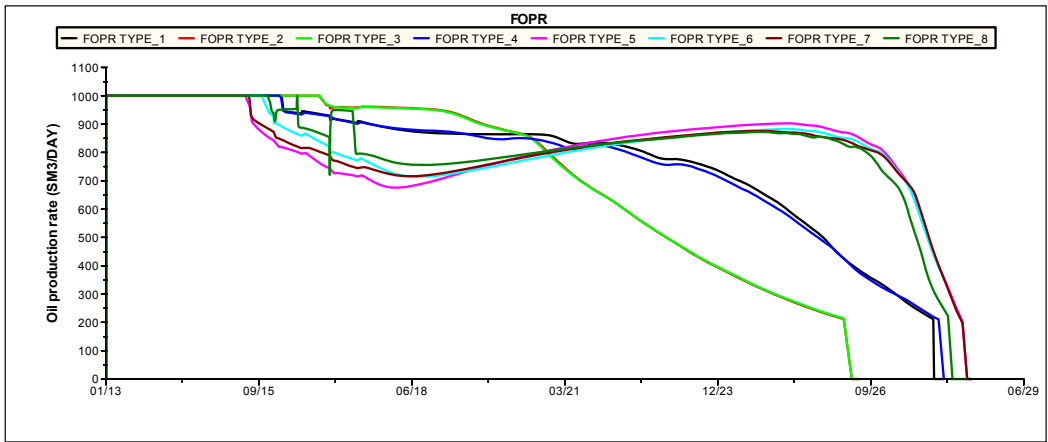


Figure 4.42 Oil production rate (all cases)

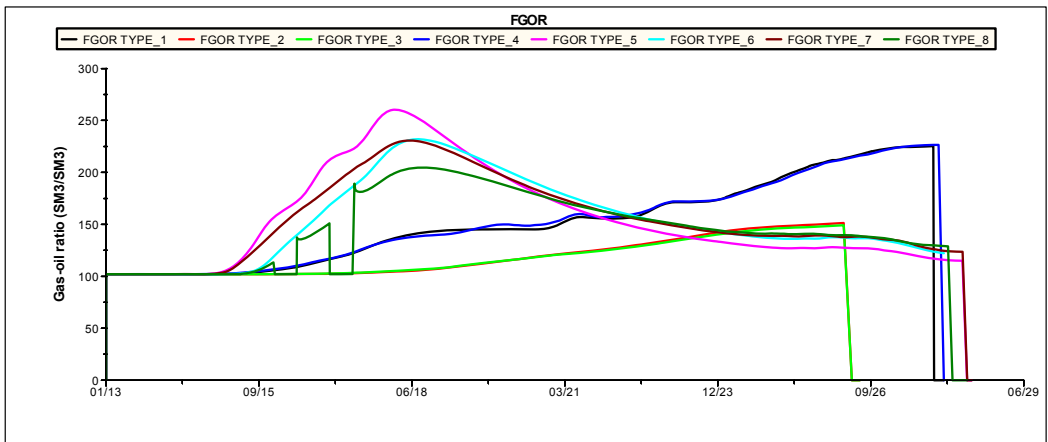


Figure 4.43 Gas-oil ratio (all cases)

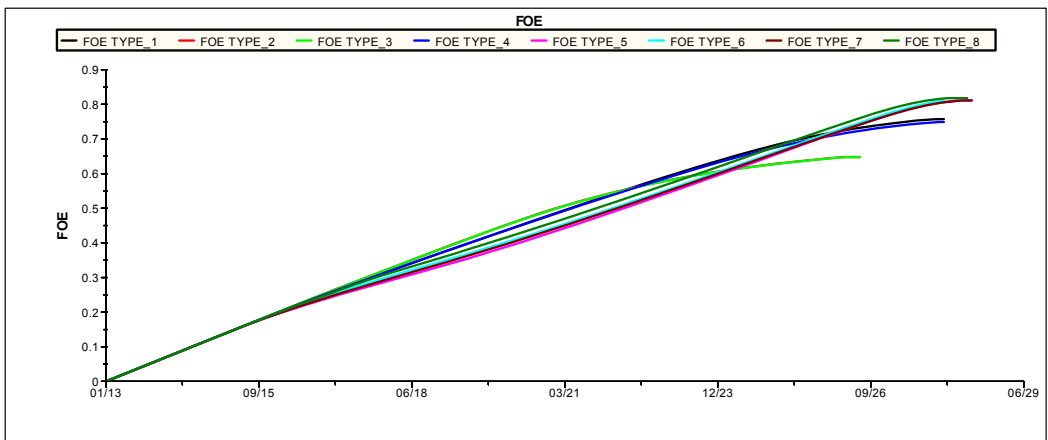


Figure 4.44 Oil recovery (all cases)

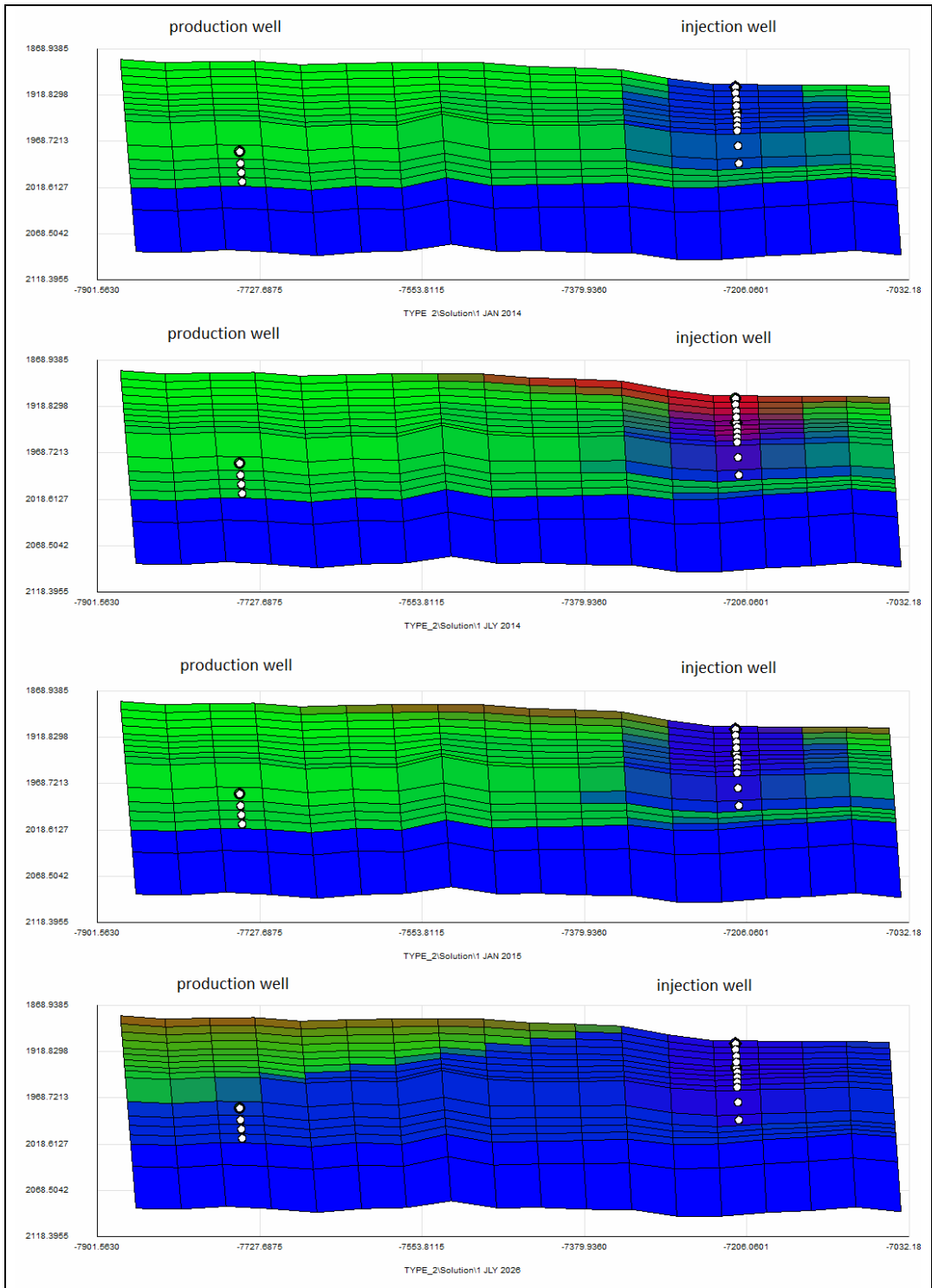


Figure 4.45 Saturation snapshots for type 2 completion. From the top – water injection, gas slug injection, water alternating gas injection, end of production. Gas – red, oil – green, water - blue

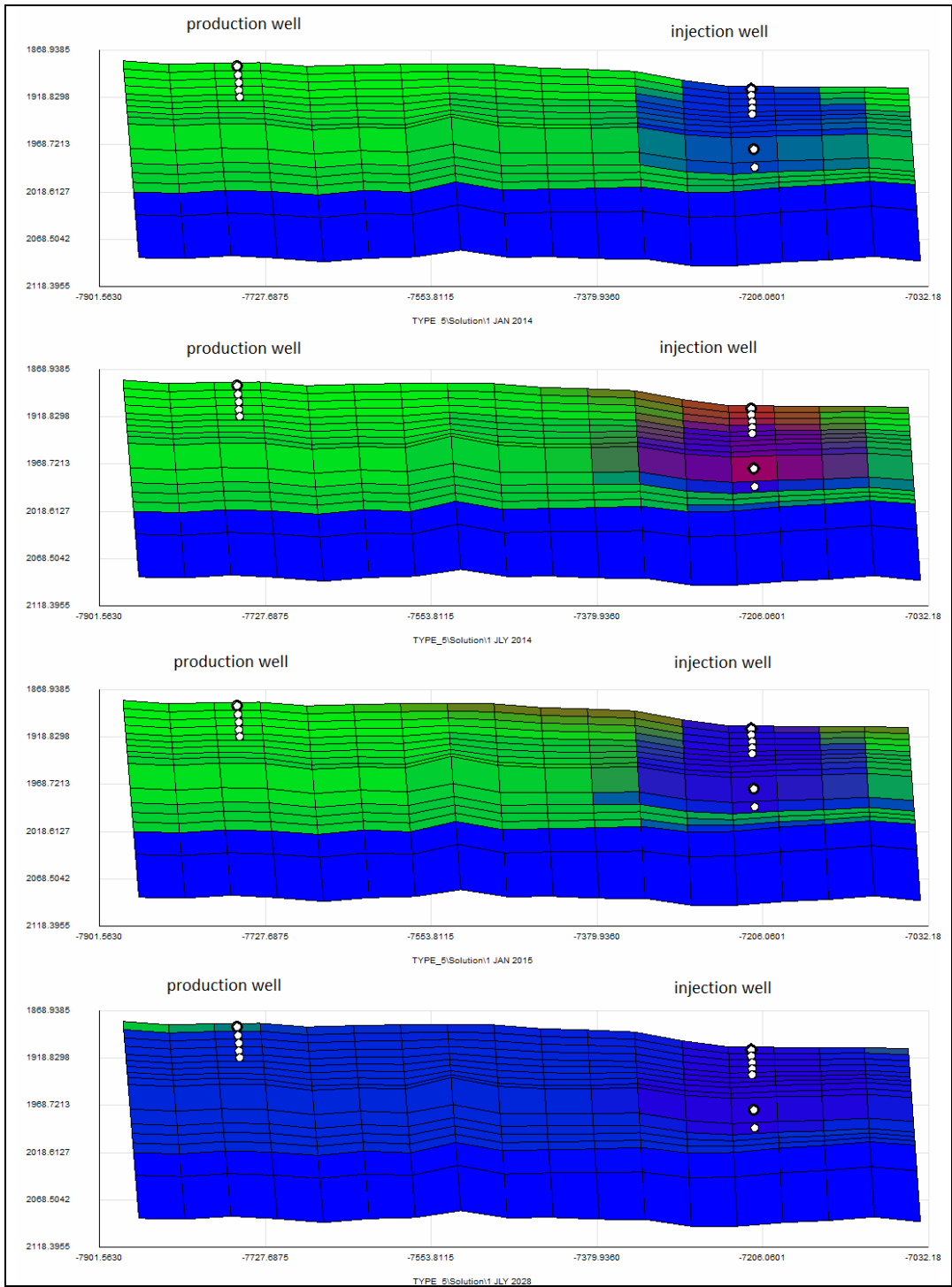


Figure 4.46 Saturation snapshots for type 5 completion. From the top – water injection, gas slug injection, water alternating gas injection, end of production. Gas – red, oil – green, water - blue

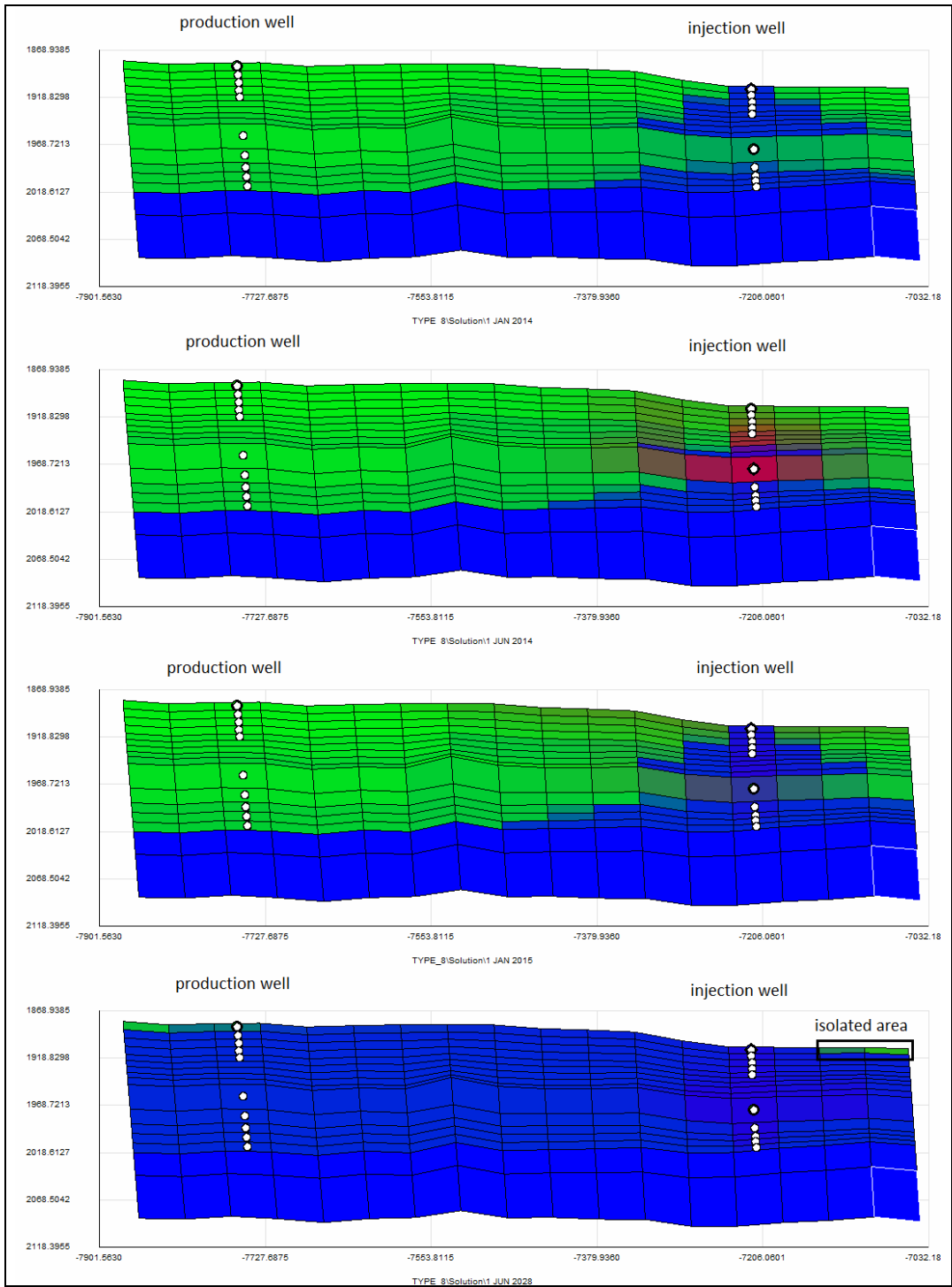


Figure 4.47 Saturation snapshots for type 8 completion. From the top – water injection, gas slug injection, water alternating gas injection, end of production. Gas – red, oil – green, water - blue



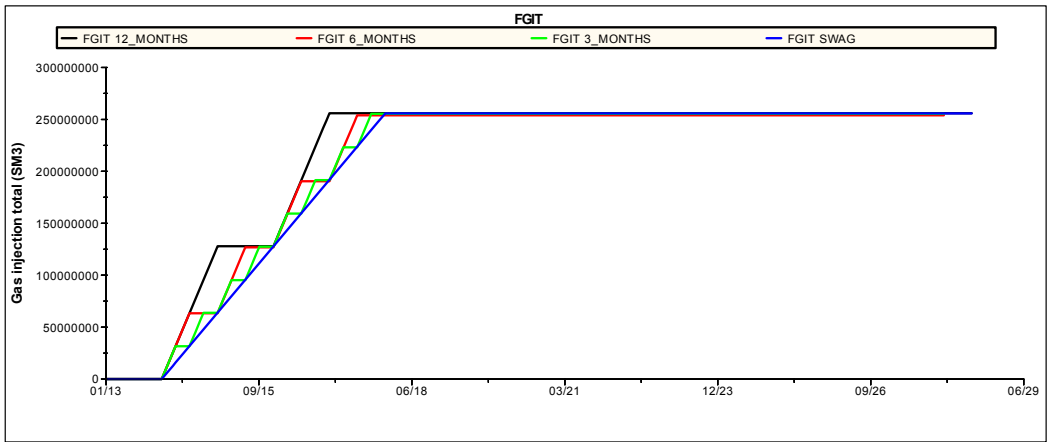


Figure 4.48 Gas injection total for different WAG half-cycle lengths and SWAG

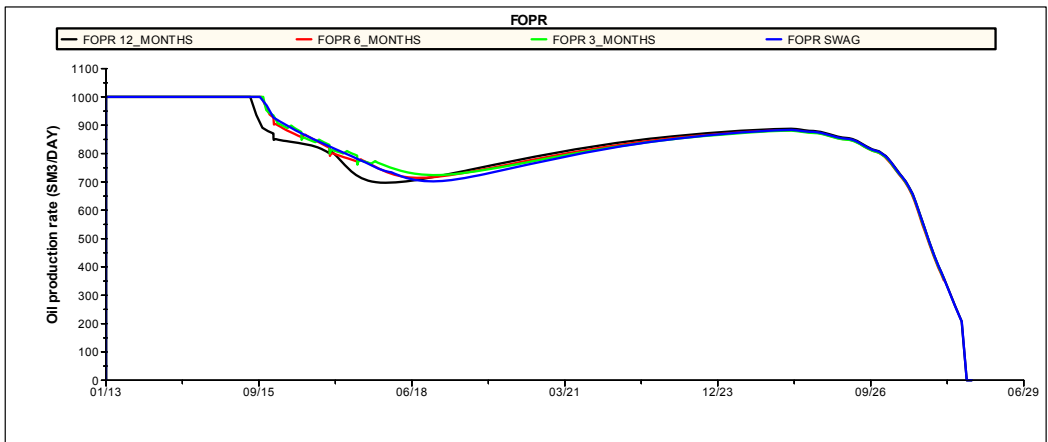


Figure 4.49 Oil production rate for different WAG half-cycle lengths and SWAG

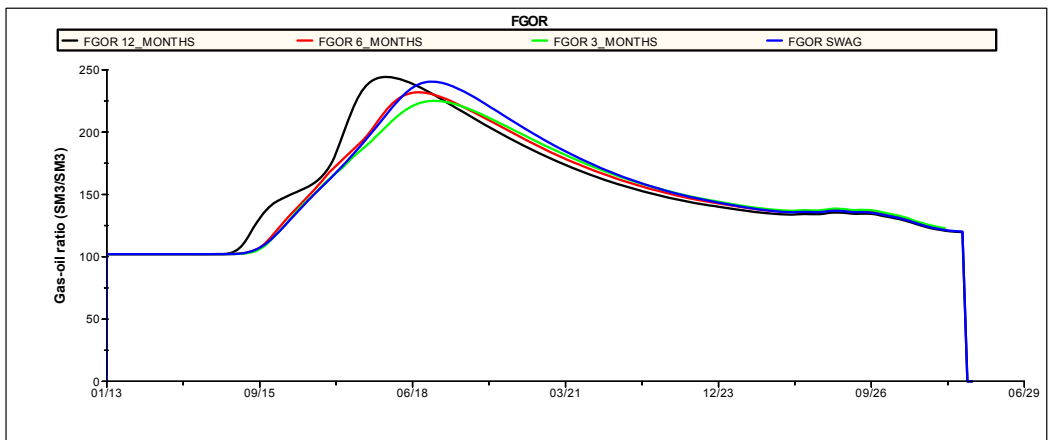


Figure 4.50 Gas-oil ratio for different WAG half-cycle lengths and SWAG

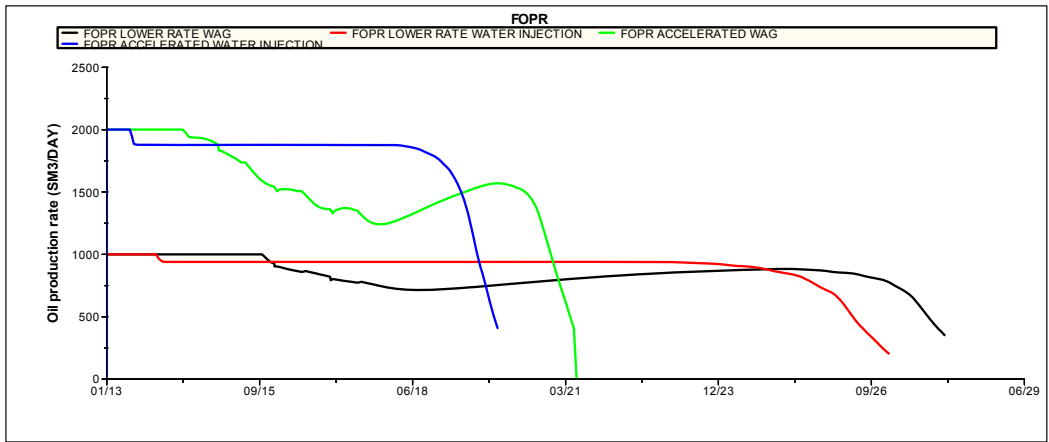


Figure 4.51 Oil production rate for accelerated production case

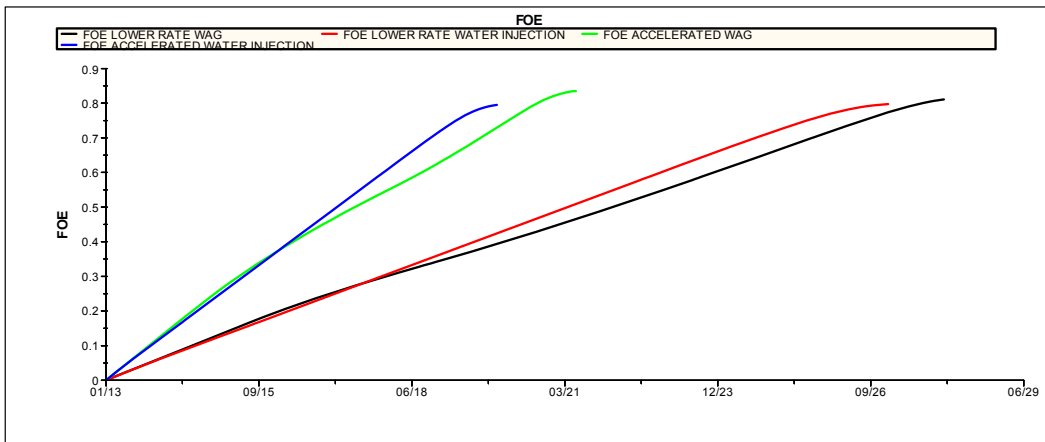


Figure 4.52 Oil recovery for accelerated production case

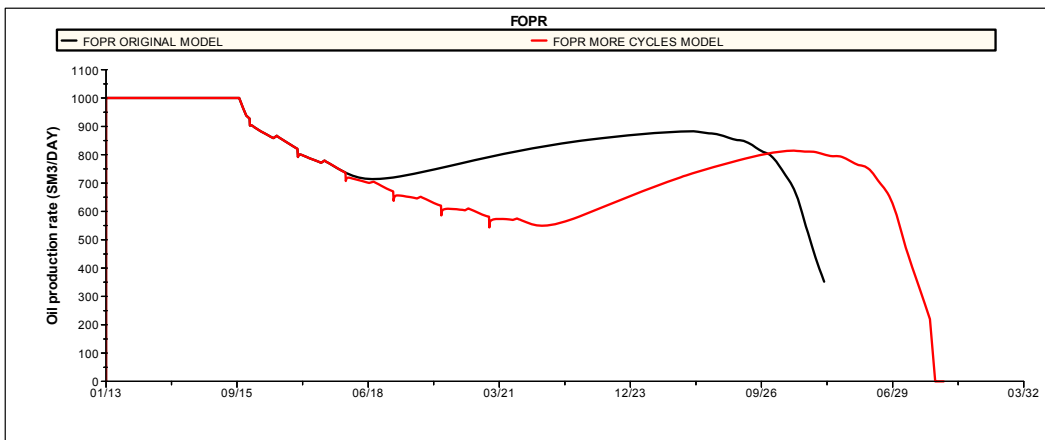


Figure 4.53 Oil production rate for number of cycles test

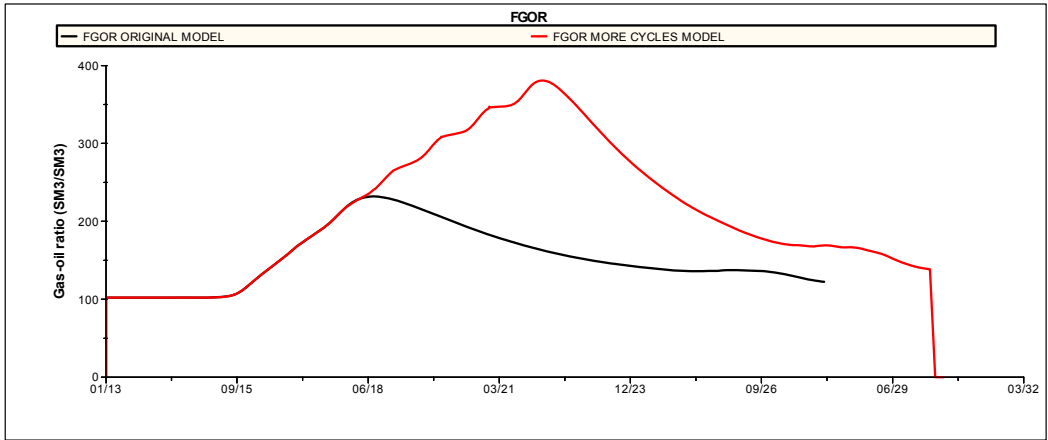


Figure 4.54 Gas-oil ratio for number of cycles test

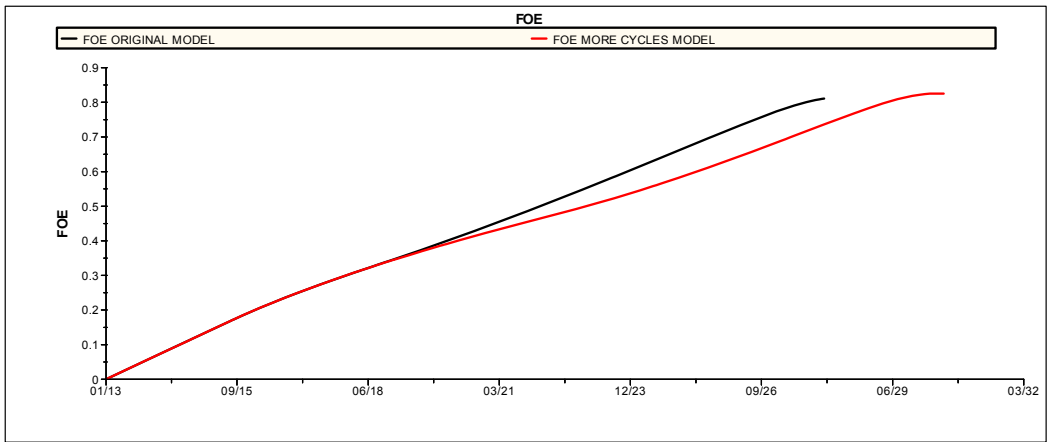


Figure 4.55 Oil recovery for number of cycles test

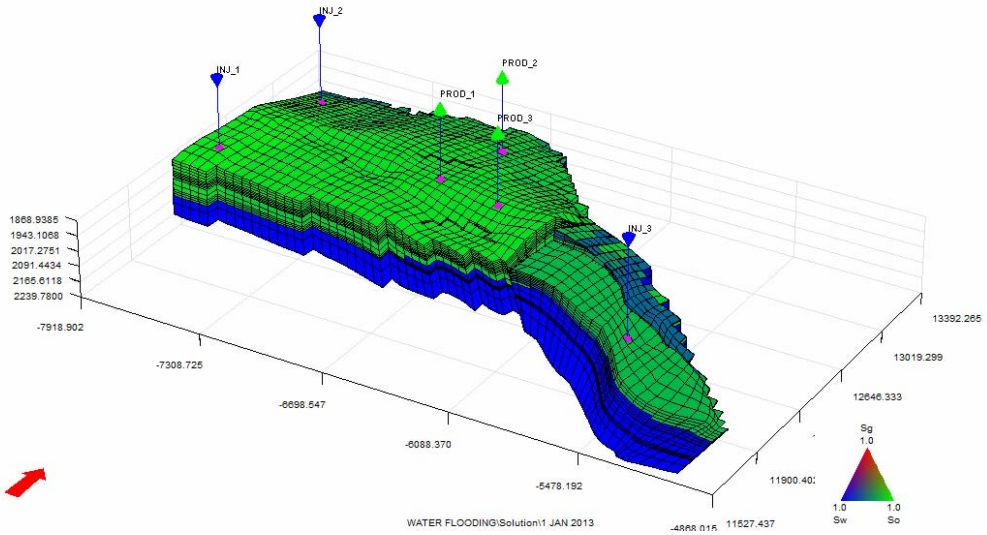


Figure 5.1 Locations of wells

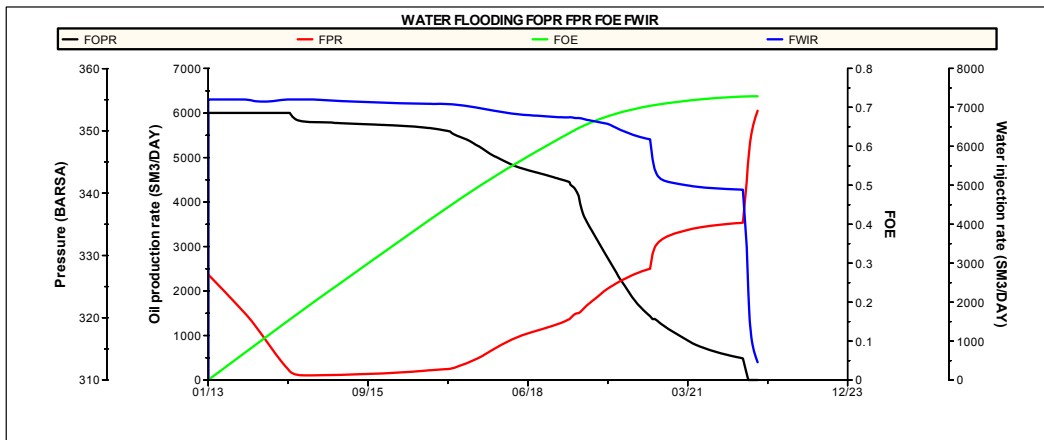


Figure 5.2 Field oil production rate, injection rate, pressure and oil recovery for water flooding scenario

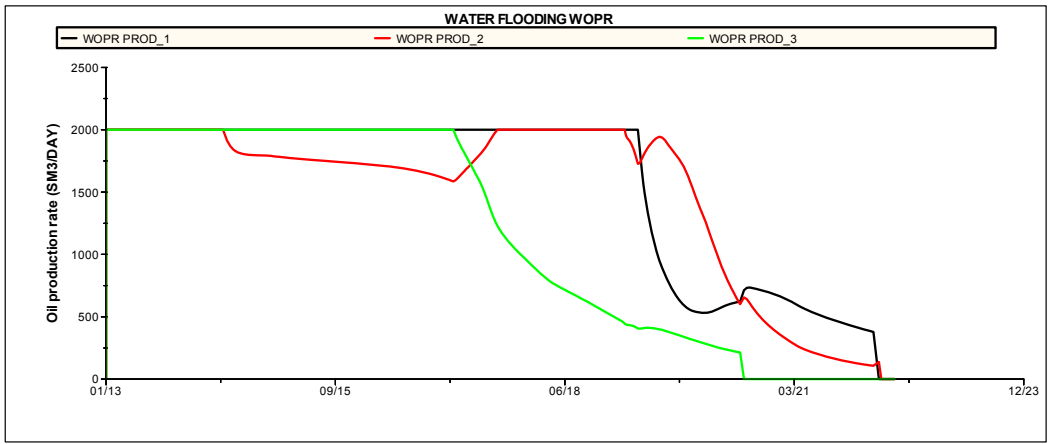


Figure 5.3 Wells oil production rates for water flooding scenario

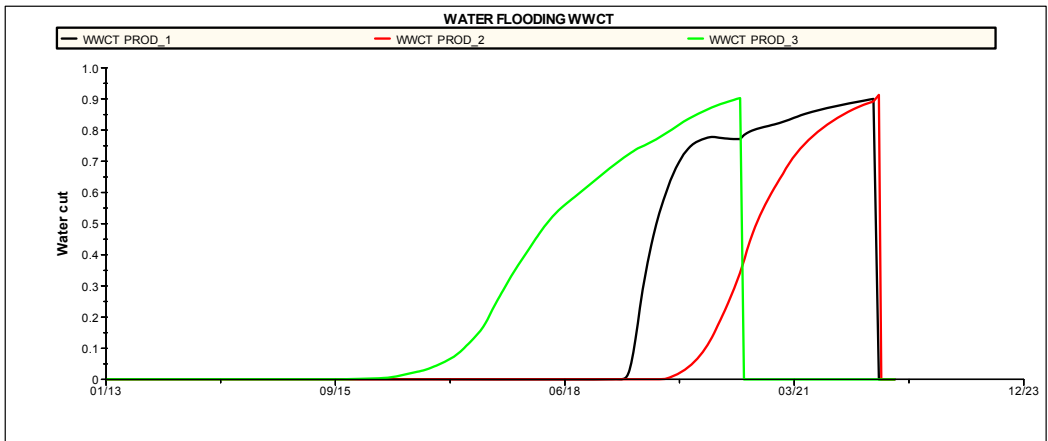


Figure 5.4 Wells water cuts for water flooding scenario

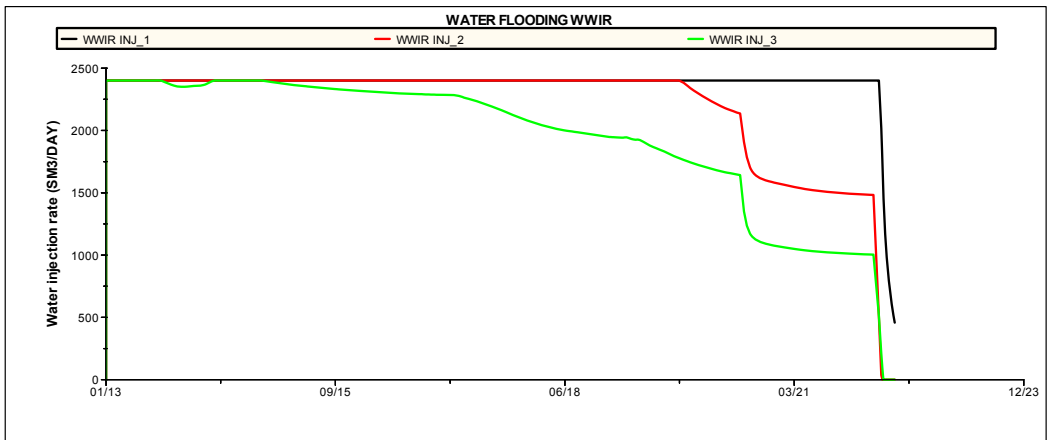


Figure 5.5 Wells water injection rates for water flooding scenario

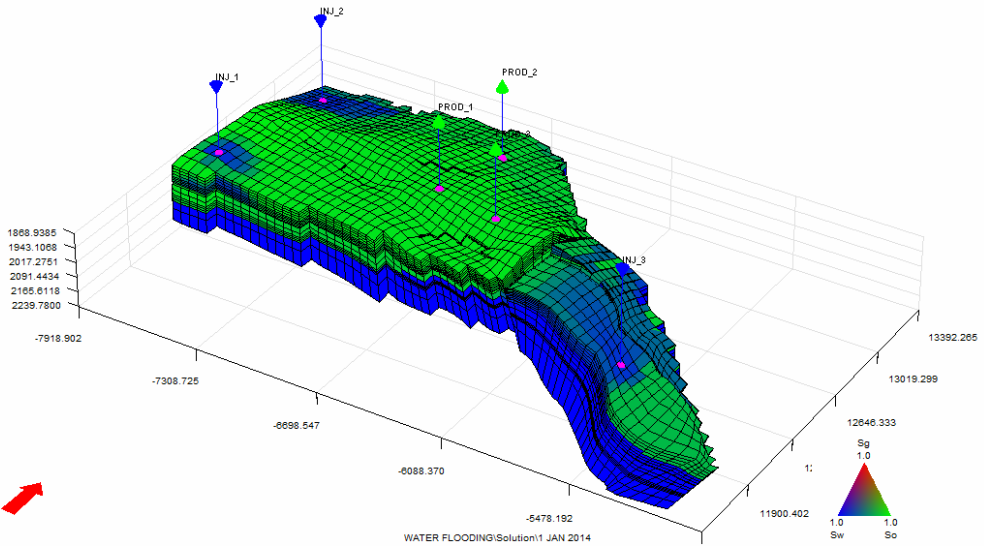


Figure 5.6 Fluids saturations after 1 year of water flooding

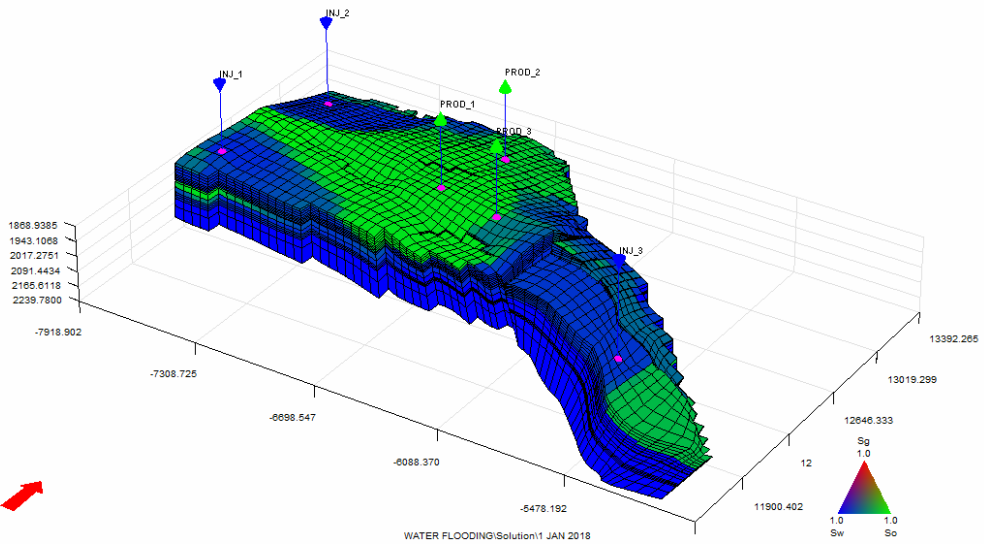


Figure 5.7 Fluids saturations after 4 years of water flooding

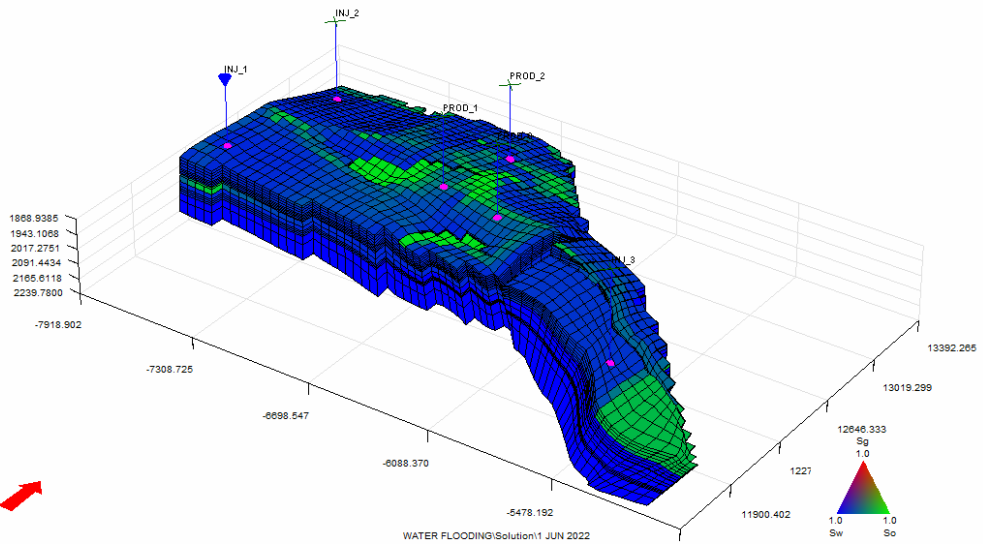


Figure 5.8 Fluids saturations at the end of production

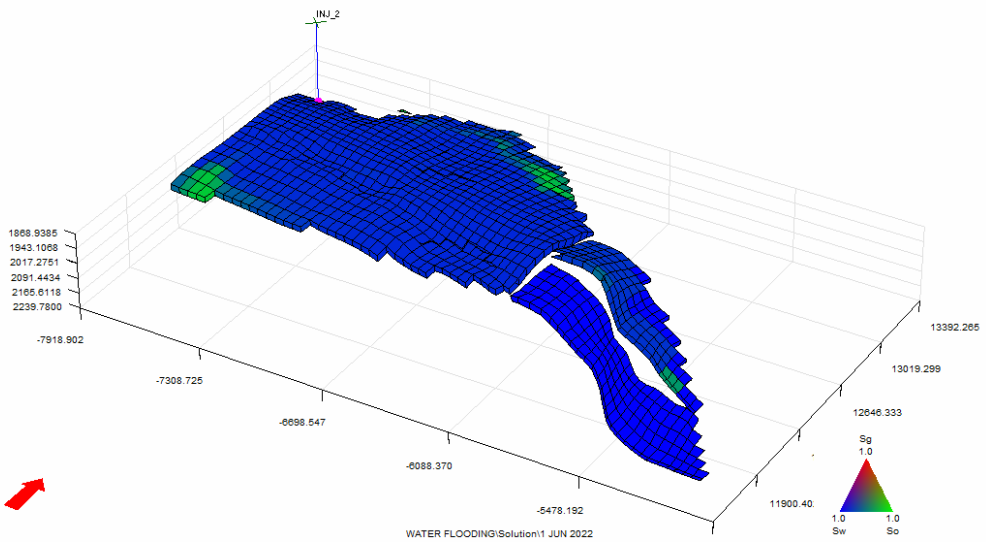


Figure 5.9 Fluids saturation in layer 11 at the end of production

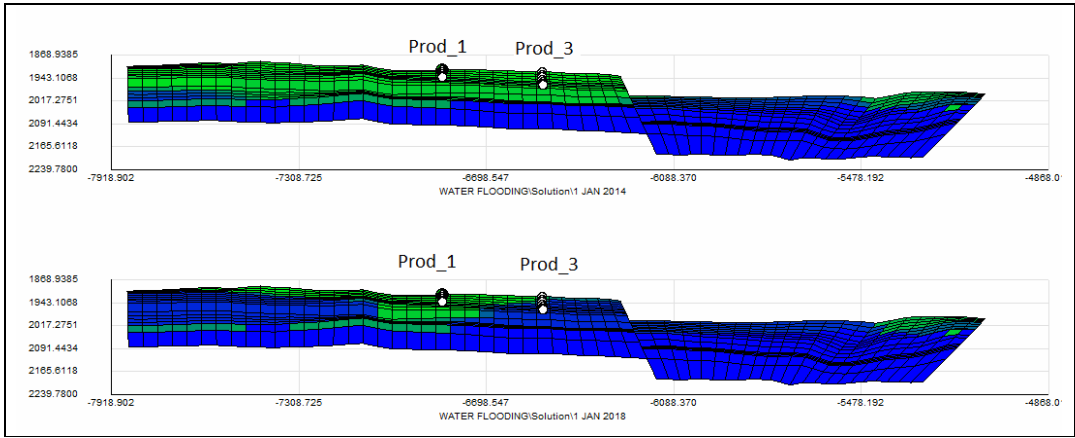


Figure 5.10 Water flooding process in cross section after 1 and 4 years of production

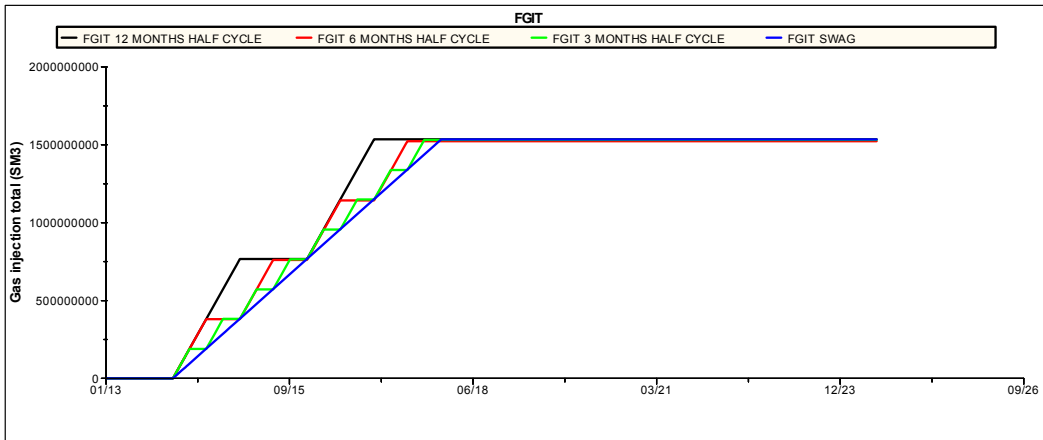


Figure 5.11 Total gas injection for early time WAG scenario

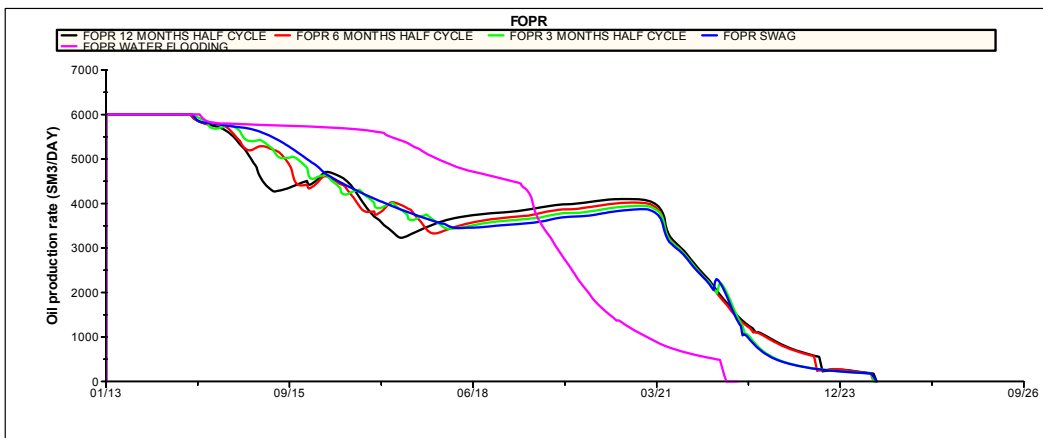


Figure 5.12 Field oil production rate for early time WAG scenario compared with water flooding scenario.



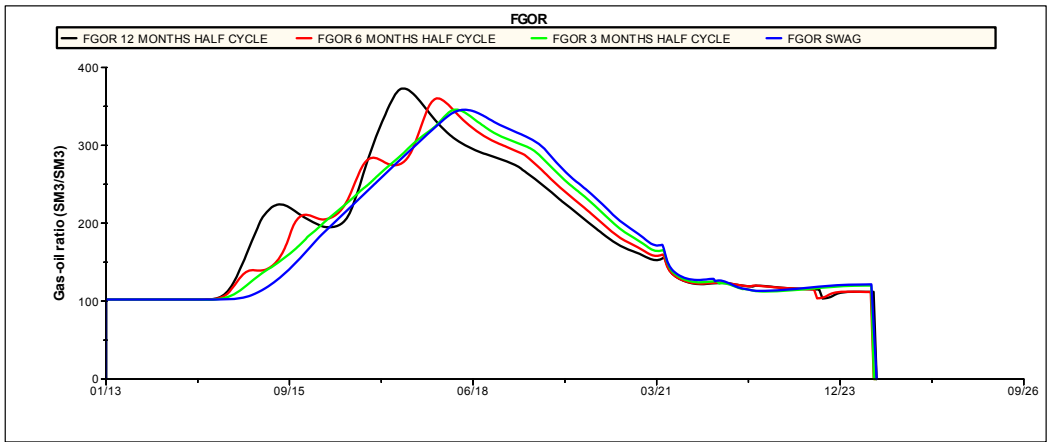


Figure 5.13 Field gas oil ratio for early time WAG scenario

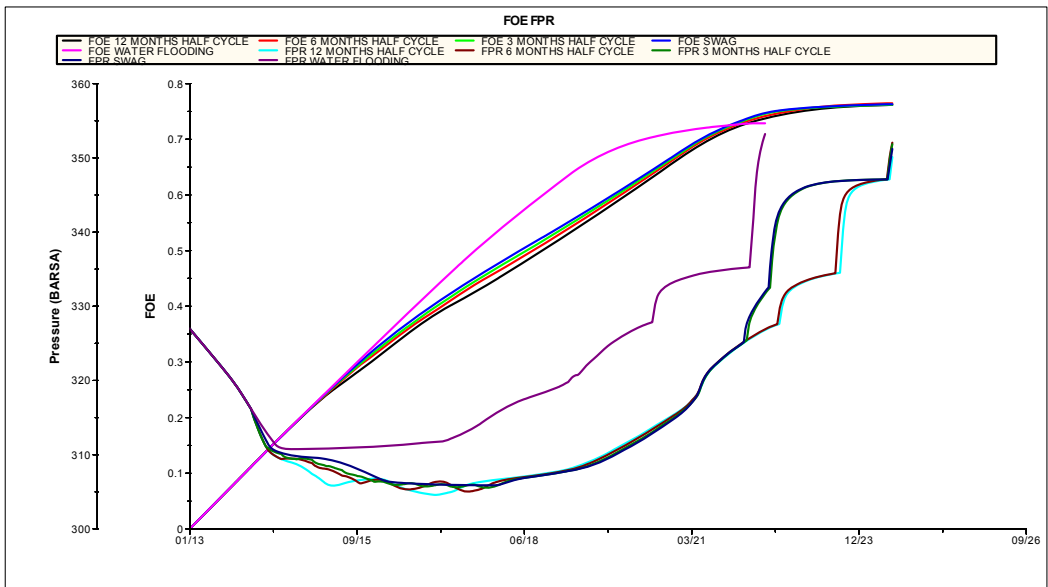


Figure 5.14 Oil recovery and field pressure for early time WAG scenario compared with water flooding scenario

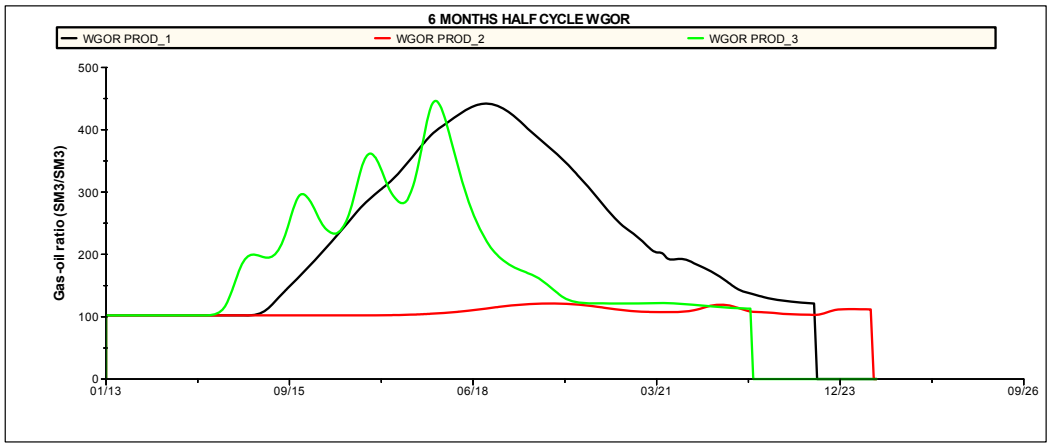


Figure 5.15 Well's gas-oil ratios for early time WAG scenario with 6 months half-cycle

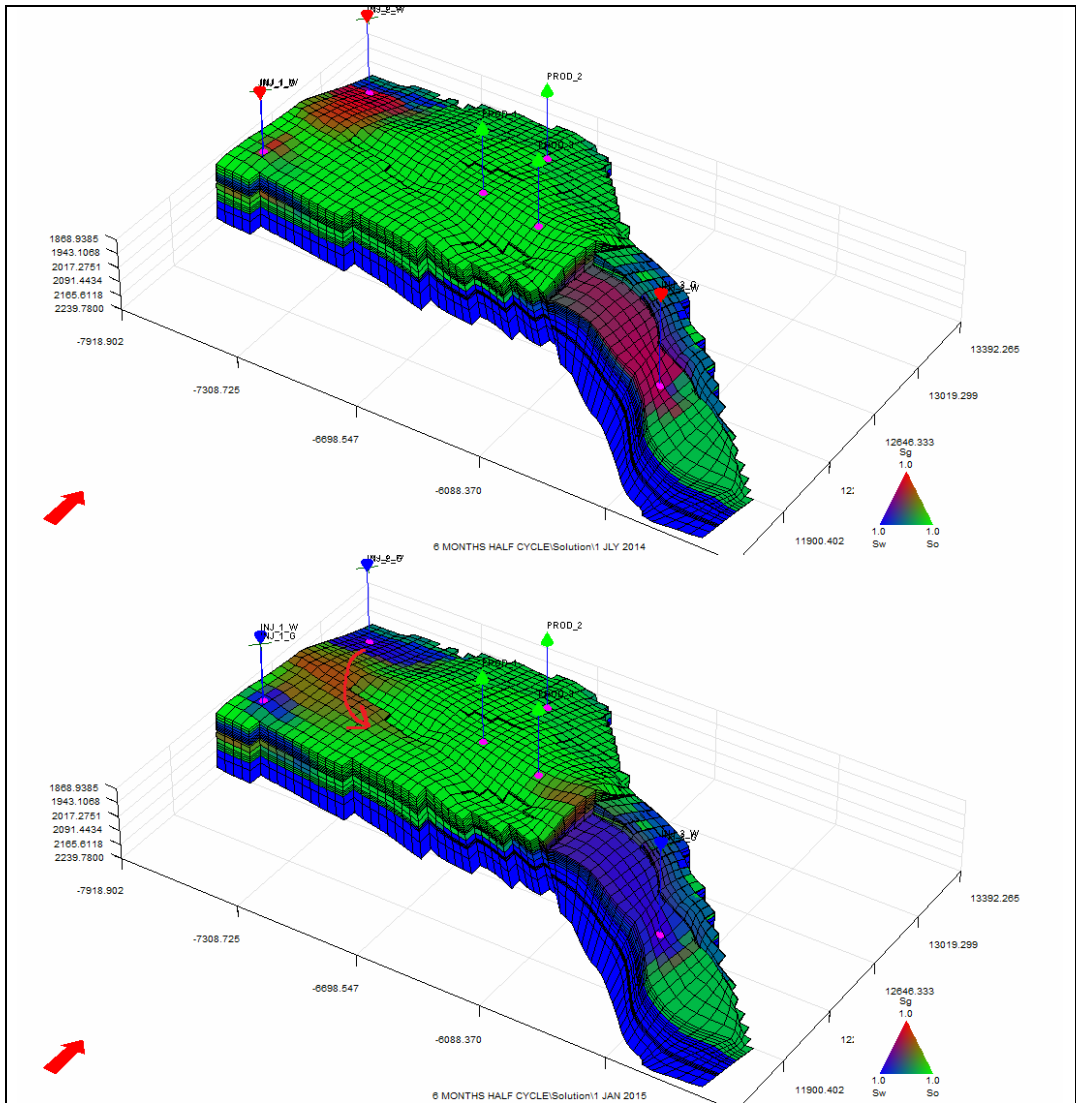


Figure 5.16 Snapshot of fluids saturations for early time WAG scenario with 6 months half-cycle. Red arrow shows direction of movement of gas injected into well Inj\_2.

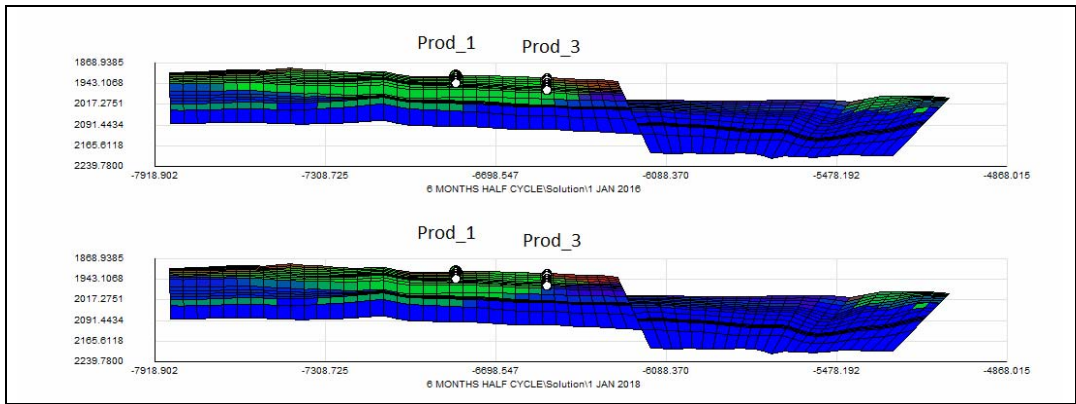


Figure 5.17 Snapshots of saturations of fluids for cross section after 1 and 3 years of WAG. Early time WAG scenario with 6 months half-cycle

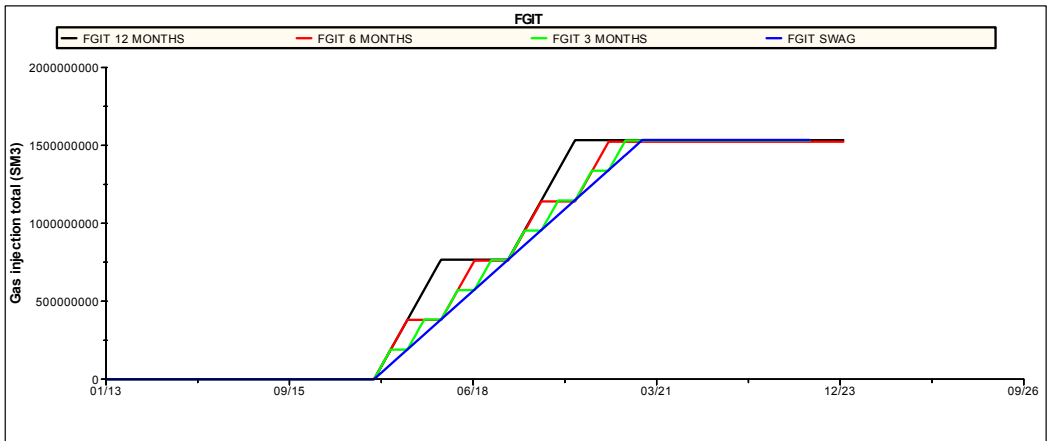


Figure 5.18 Total gas injection for late time WAG scenario

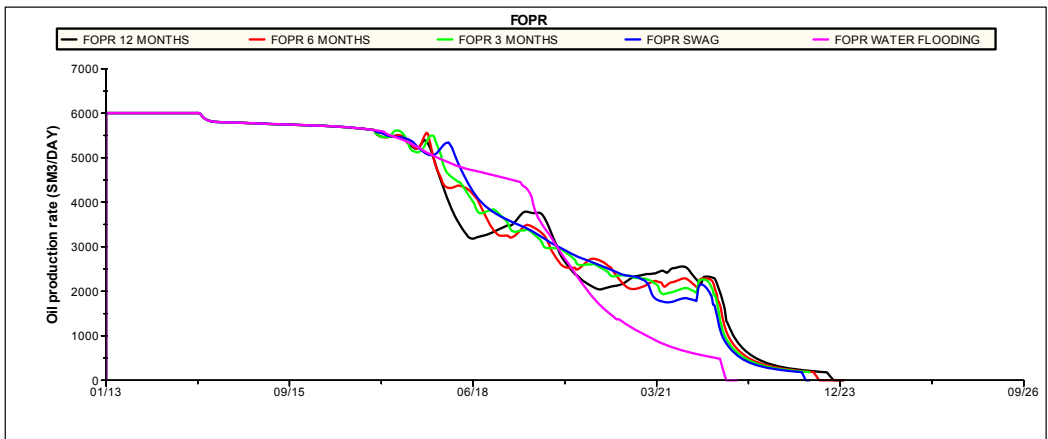


Figure 5.19 Field oil production rate for late time WAG scenario compared with water flooding scenario.

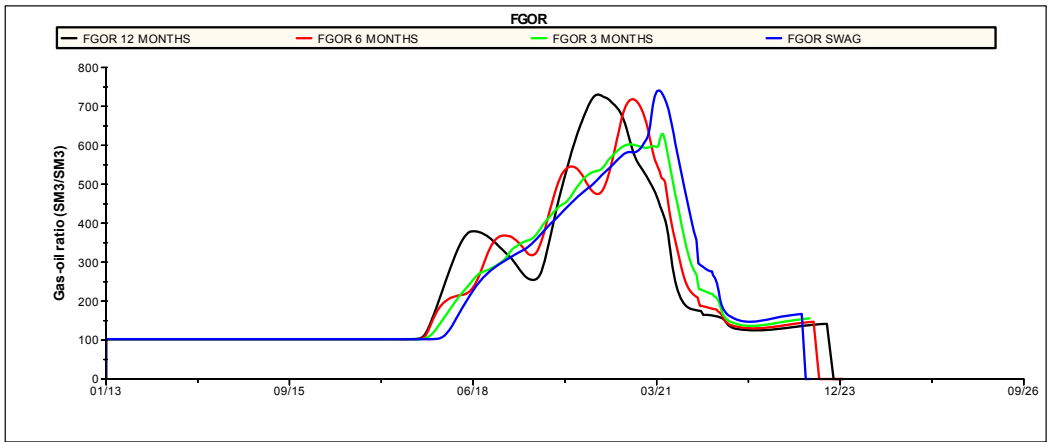


Figure 5.20 Field gas-oil ratio for late time WAG scenario

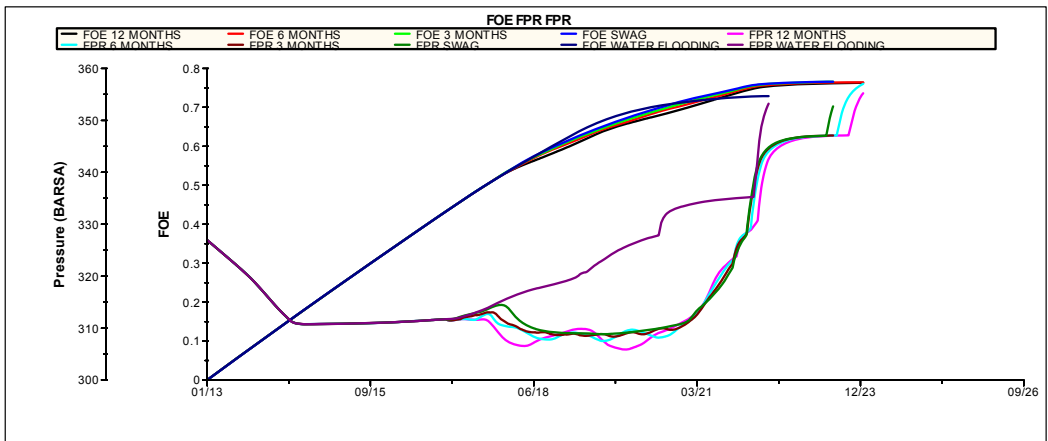


Figure 5.21 Field pressures and oil recovery factors for late time WAG scenario and water flooding

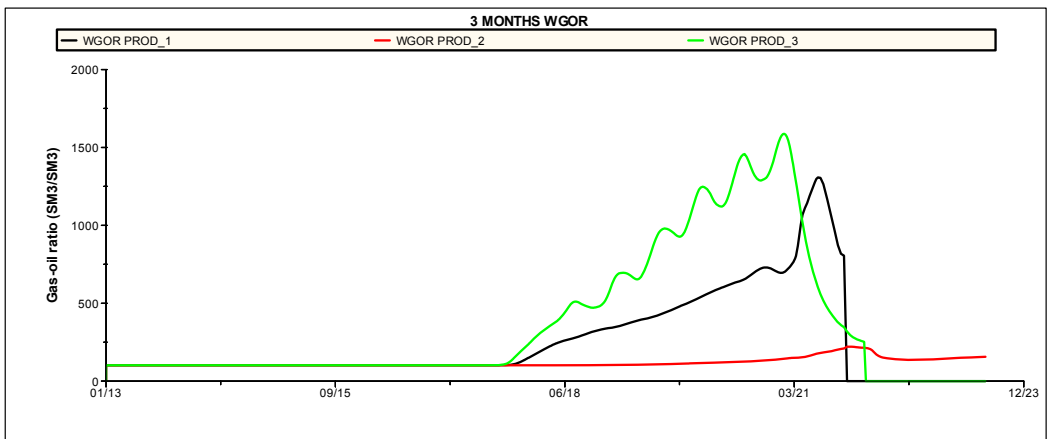


Figure 5.22 Well's gas-oil ratios for early time WAG scenario with 6 months half-cycle

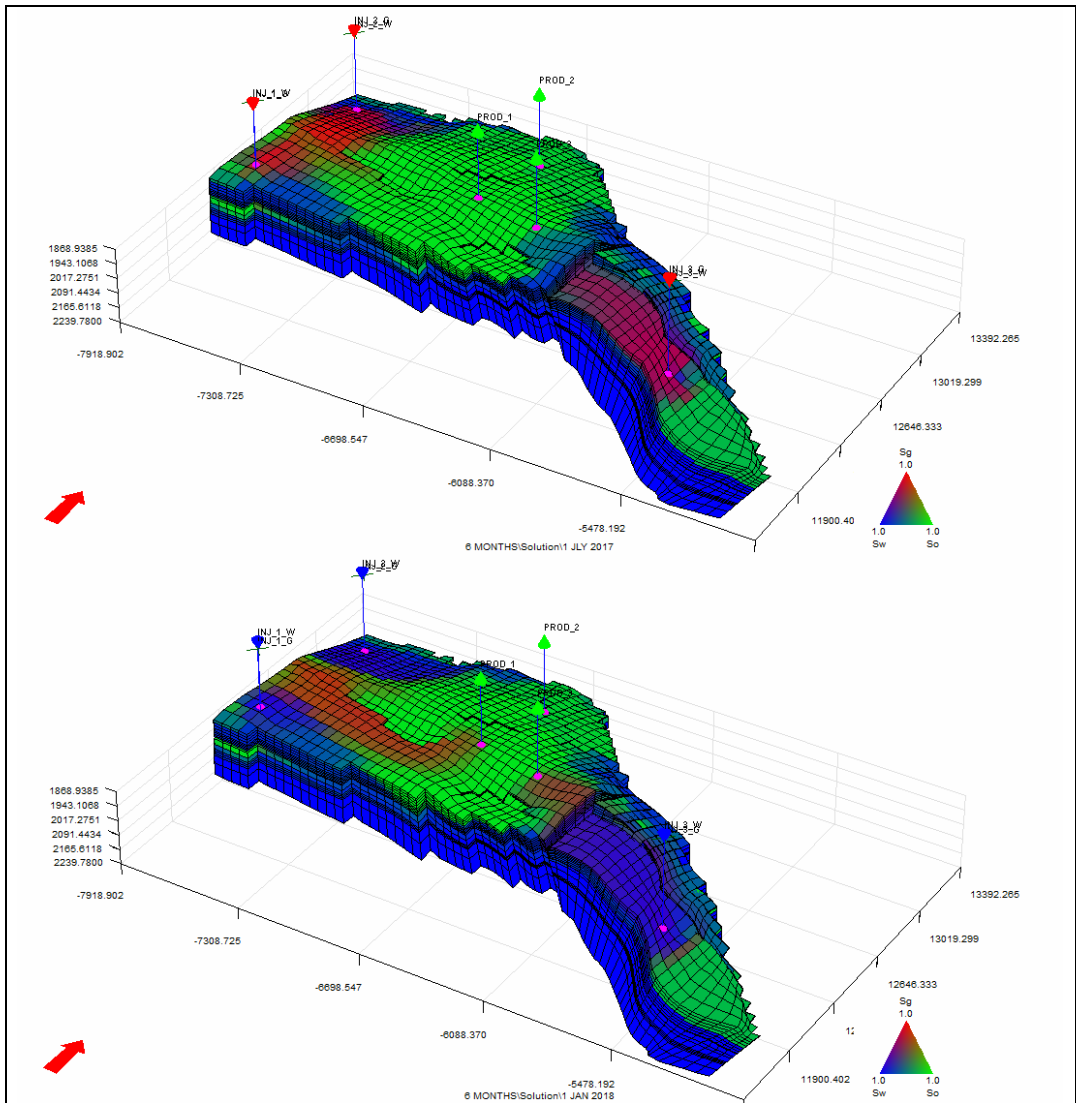


Figure 5.23 Fluids saturations snapshots after 6 months and 12 months after start of WAG injection. Late time WAG scenario.

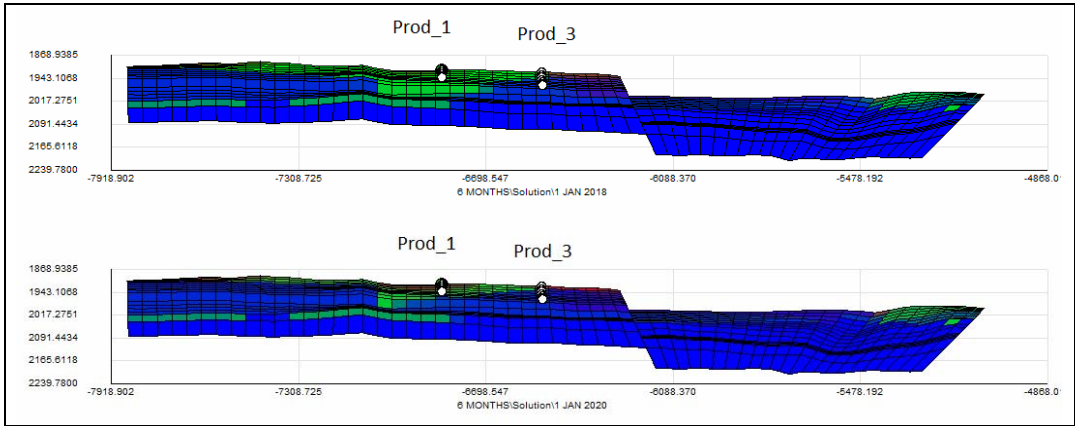


Figure 5.24 Fluids saturations snapshots in cross section after 1 year and 3 years after start of WAG injection. Late time WAG scenario

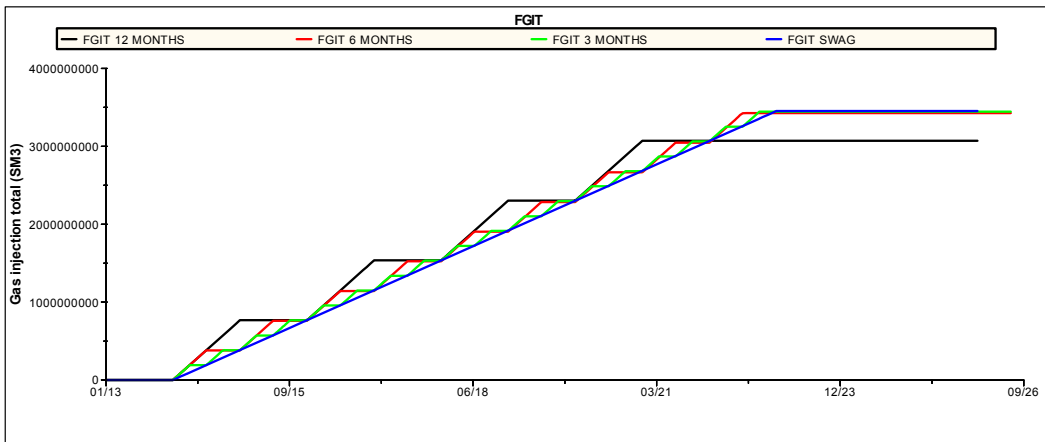


Figure 5.25 Total gas injection for life time WAG scenario

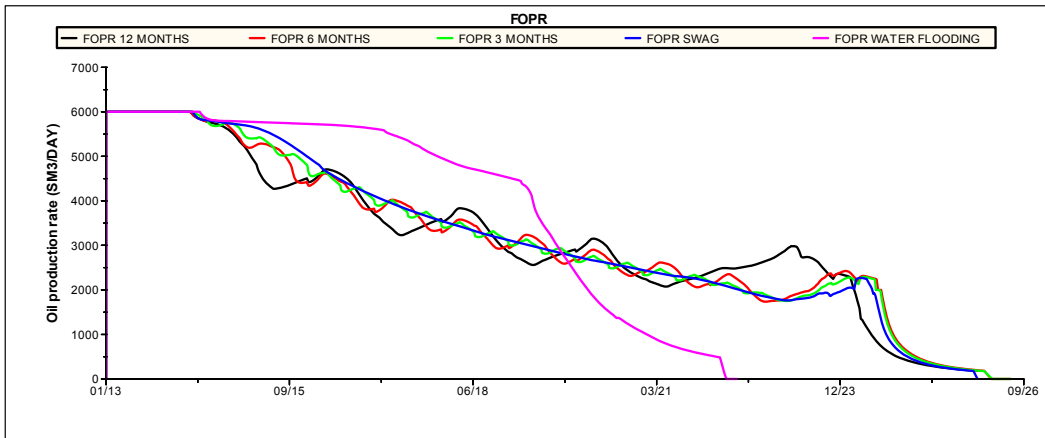


Figure 5.26 Field oil production rate for life time WAG scenario compared with water flooding scenario

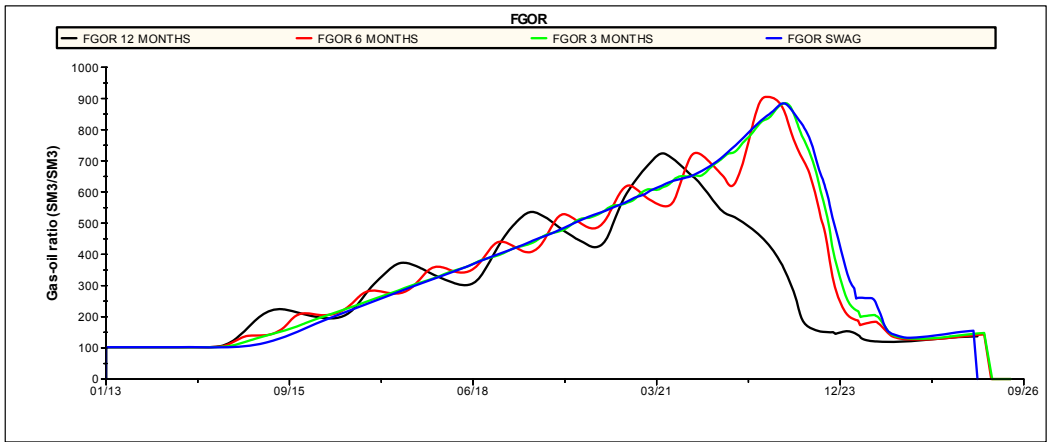


Figure 5.27 Field gas-oil ratio for life time WAG scenario

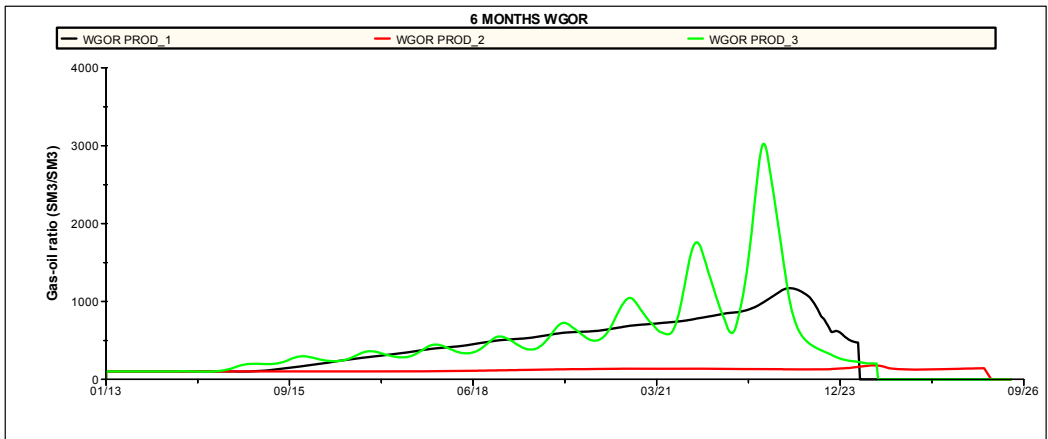


Figure 5.28 Wells gas-oil ratio for life time WAG scenario with 6 months half-cycle

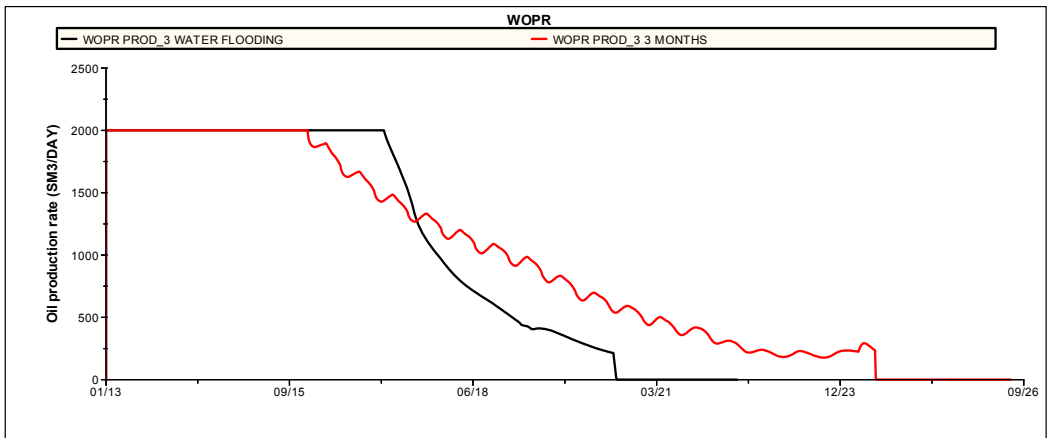


Figure 5.29 Oil production rate for well Prod\_3 with 3 months half-cycle



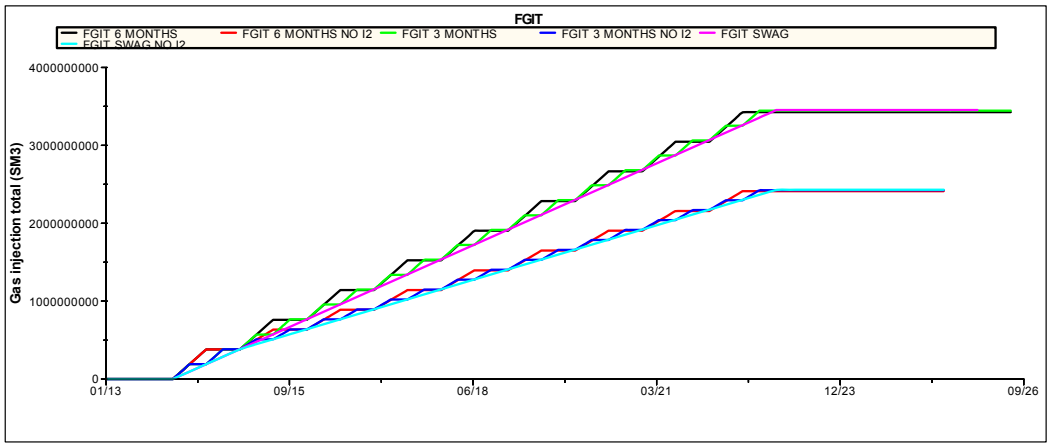


Figure 5.30 Total gas injection for life time WAG scenario with limited gas injection into well Inj\_2.

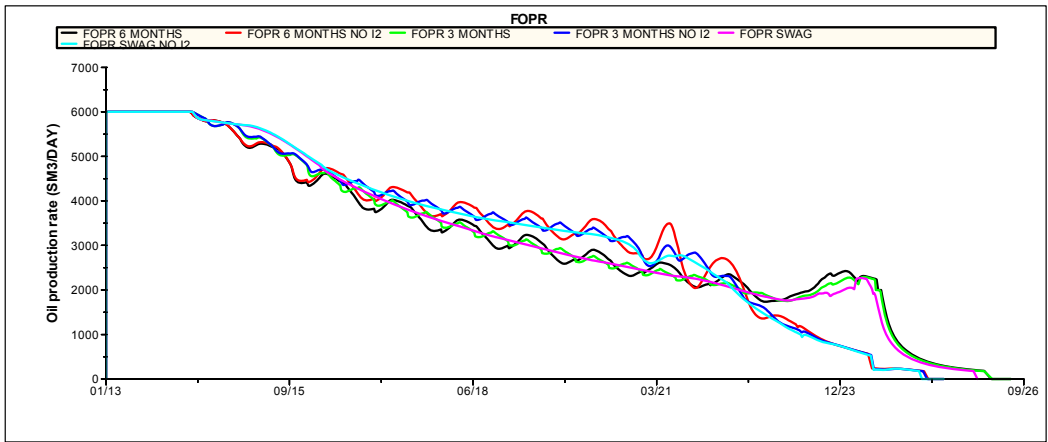


Figure 5.31 Field oil production rate for the scenario with limited injection of gas in well Inj\_2

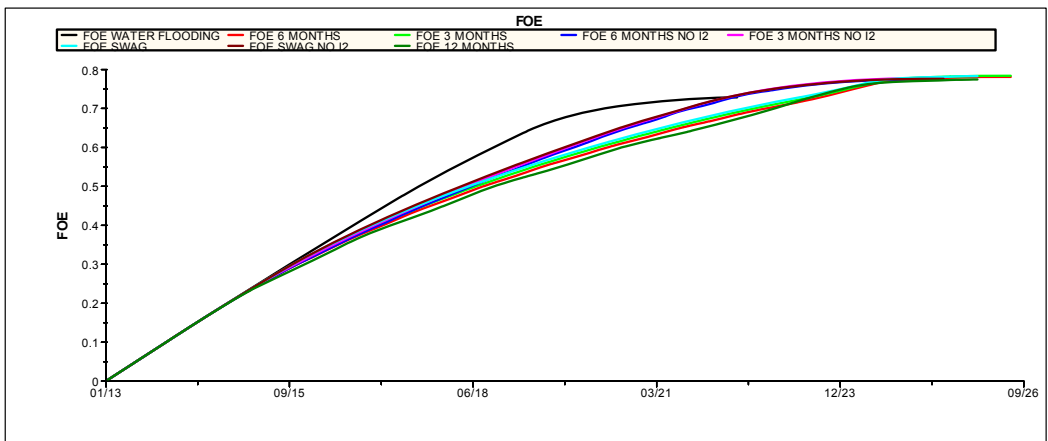


Figure 5.32 Oil recovery for life time WAG scenario

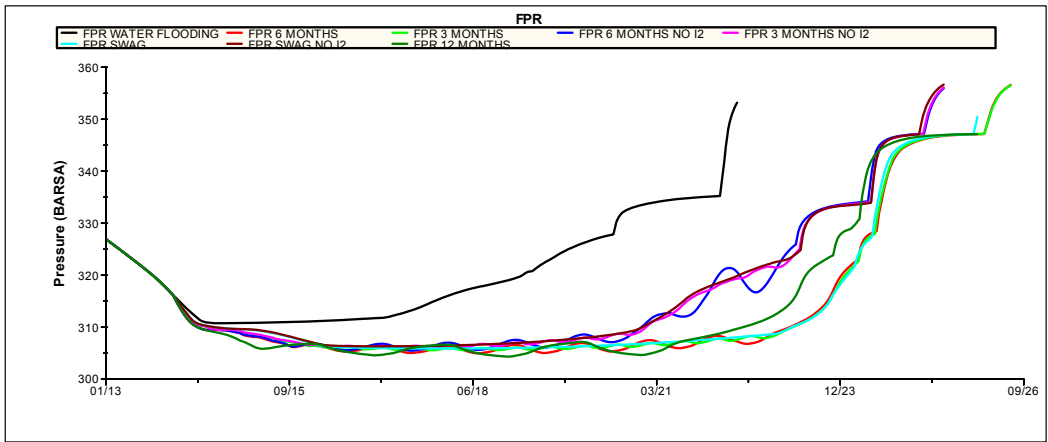


Figure 5.33 Field pressure for life time WAG scenario

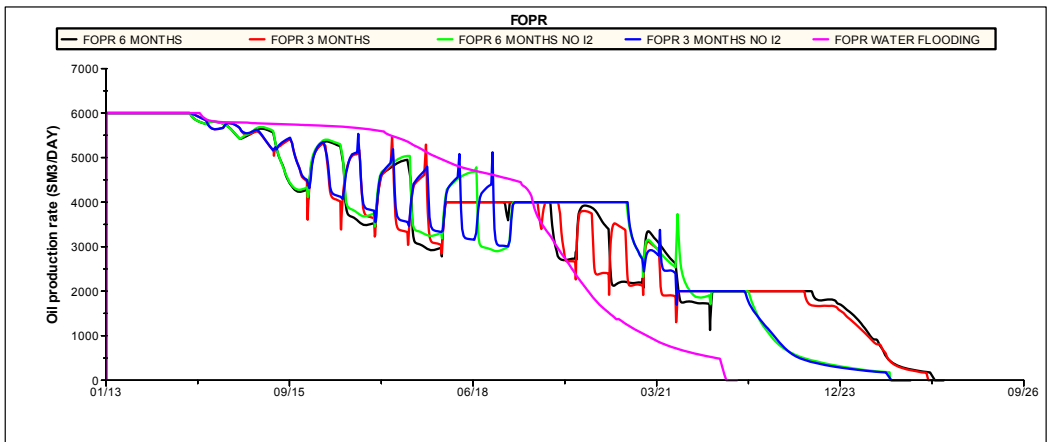


Figure 5.34 Oil production rate for changing completion WAG scenario

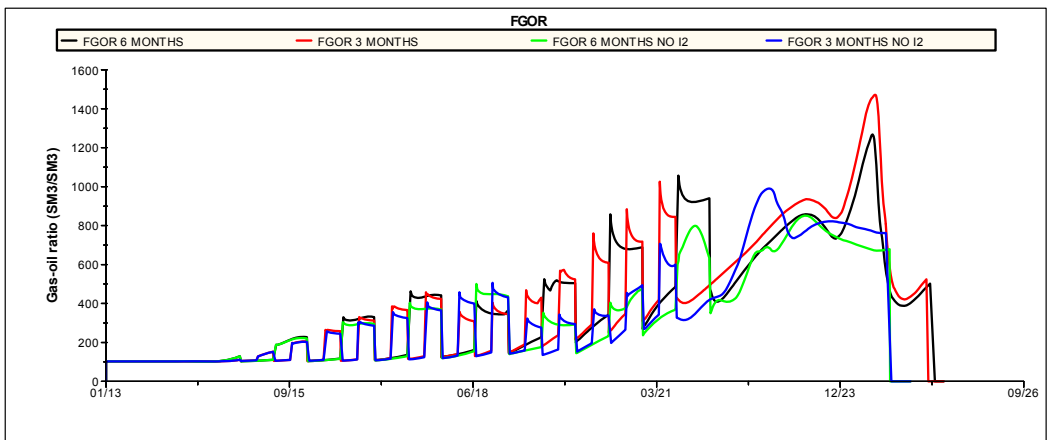


Figure 5.35 Field gas-oil ratio for the changing completion WAG scenario

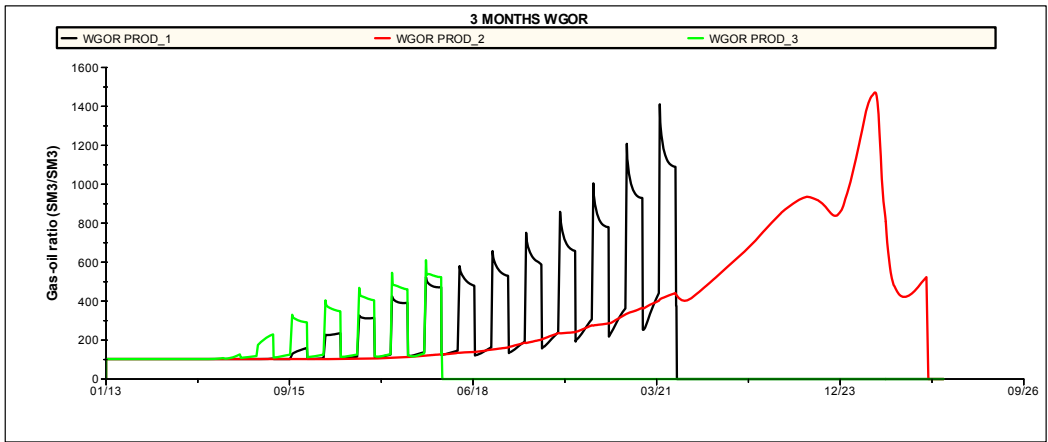


Figure 5.36 Gas-oil ratio for wells for the changing completion WAG scenario

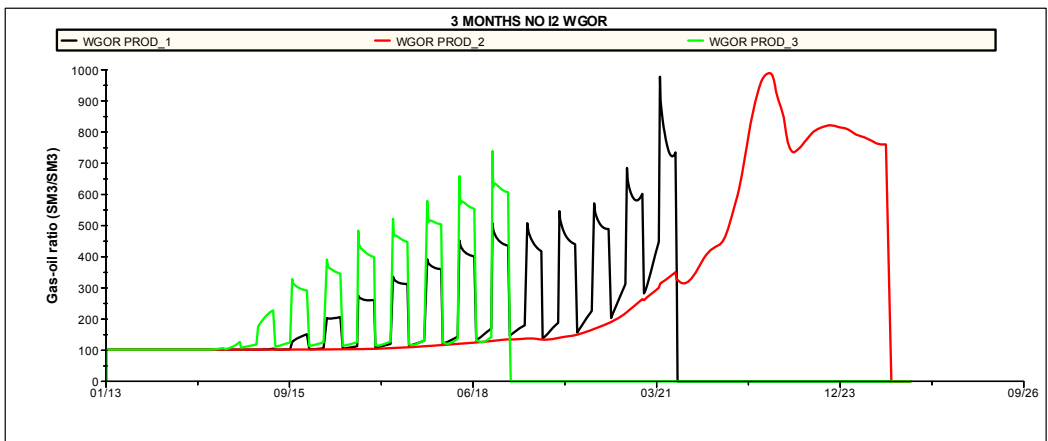


Figure 5.37 Gas-oil ratio for wells for the changing completion WAG scenario

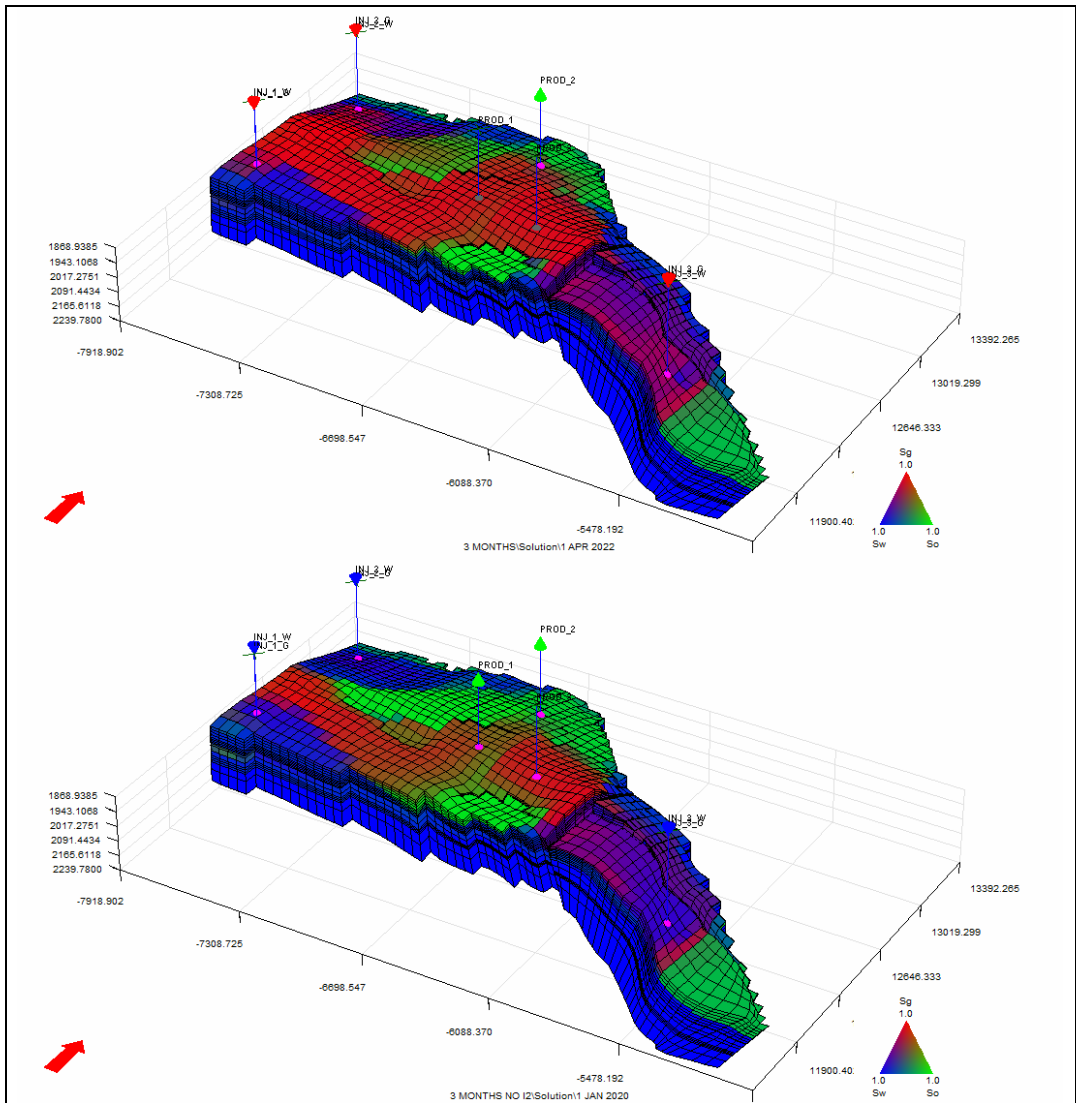


Figure 5.38 Snapshot of fluids' saturations for the changing completion WAG scenario (upper snapshot – gas is injected into all wells, lower snapshot – limited injection into well Inj\_2)

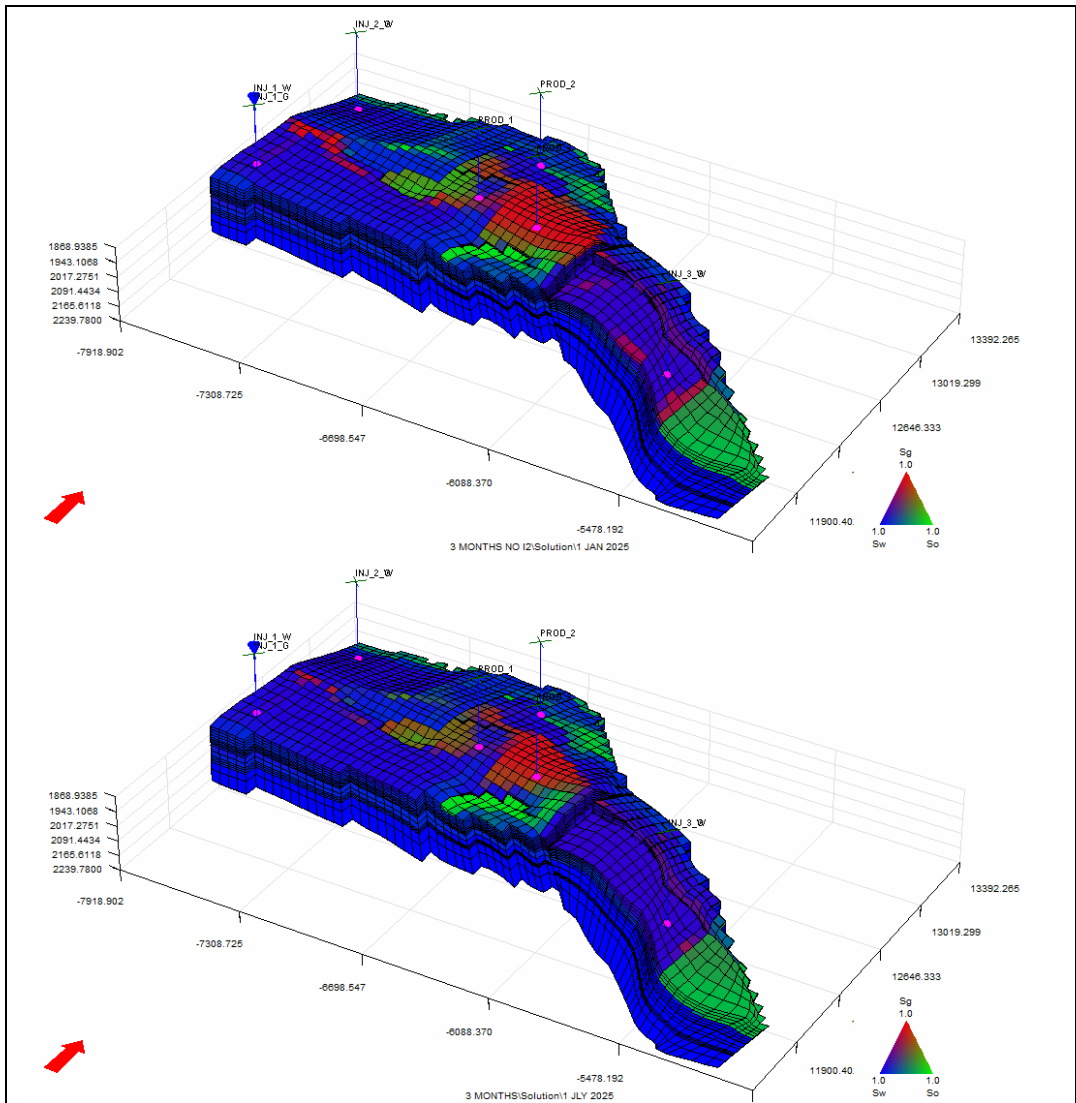


Figure 5.39 Snapshot of fluids' saturations for the changing completion WAG scenario (upper snapshot – gas is injected into all wells, lower snapshot – limited injection into well Inj\_2)

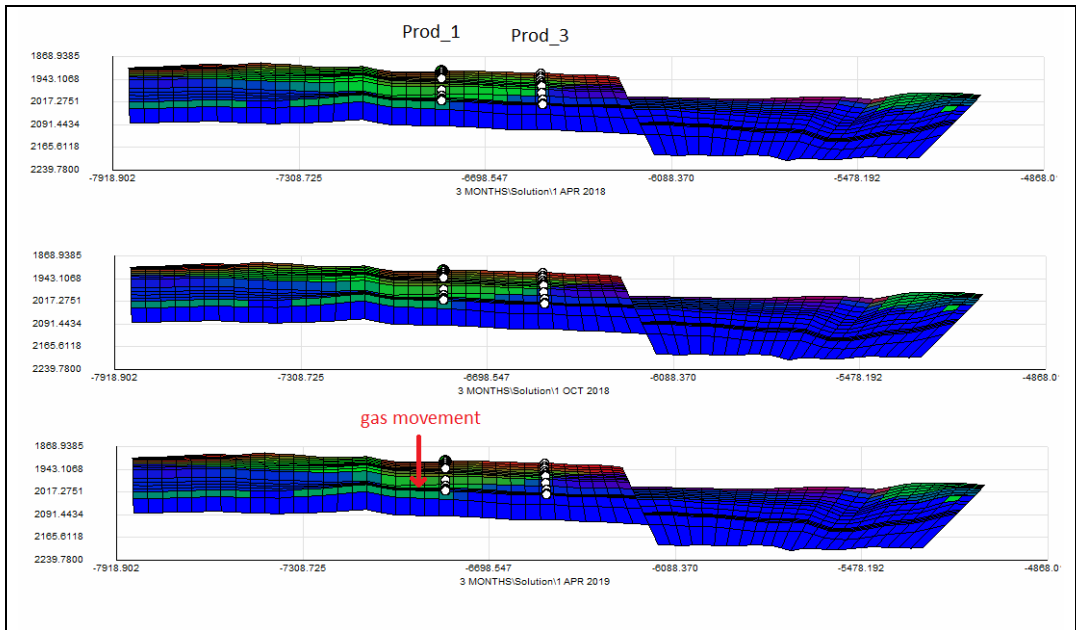


Figure 5.40 Gas movement in cross section direction. Injection into all wells

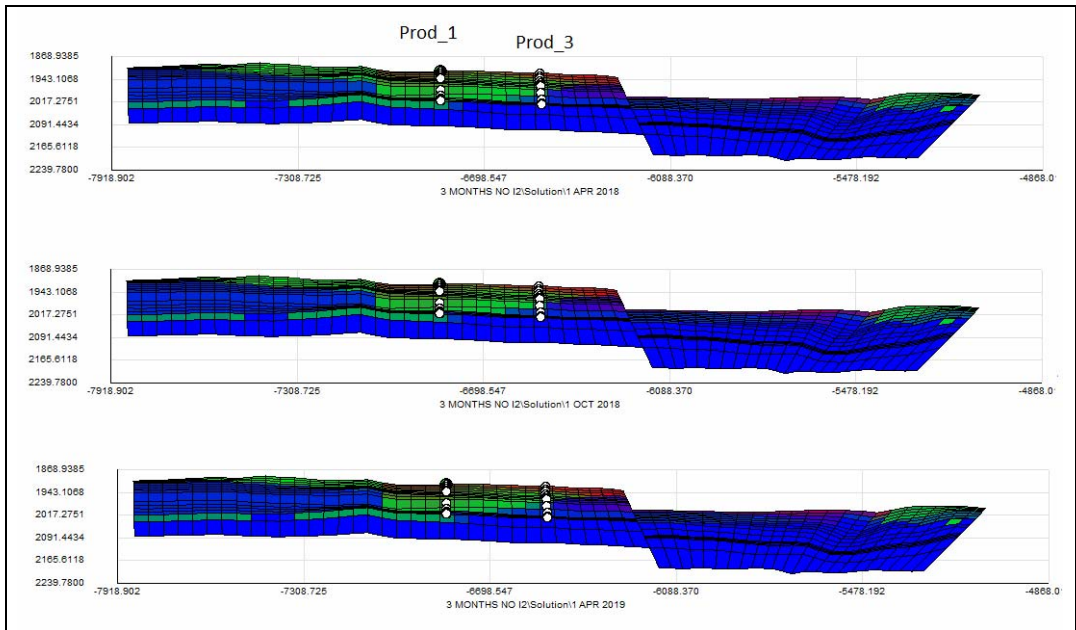


Figure 5.41 Gas movement in cross section direction. Limited injection

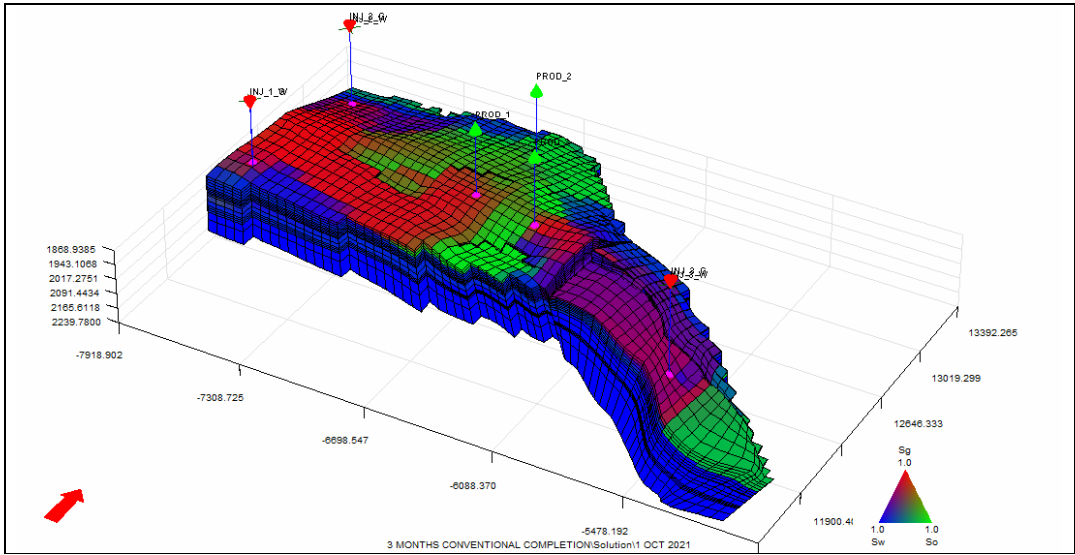


Figure 5.42 Snapshot of fluids' saturations for the life time WAG 3 months half-cycle scenario with conventional completion

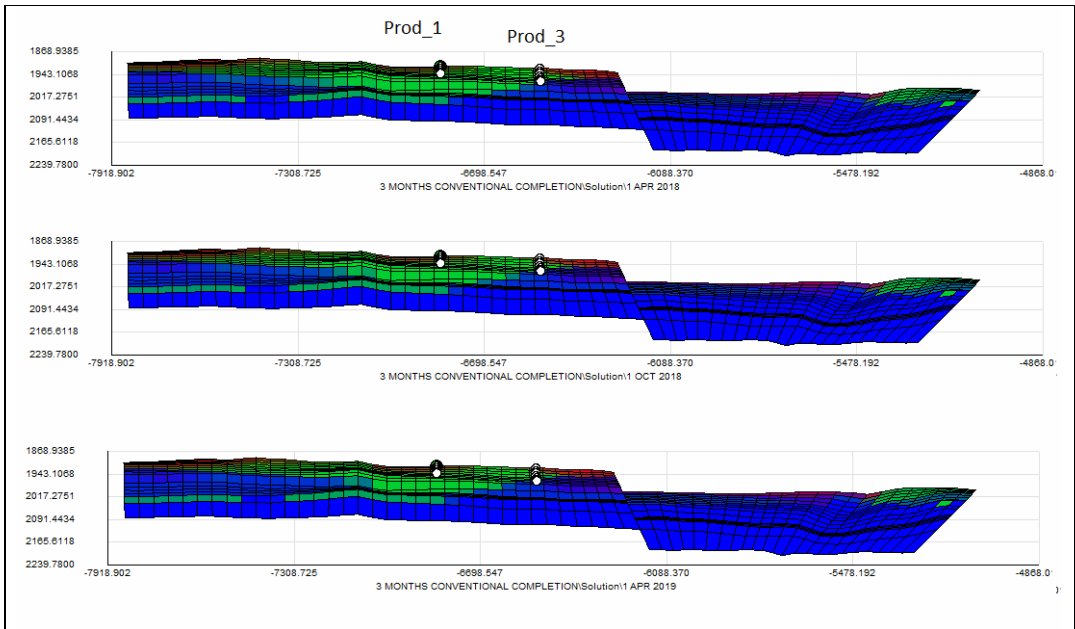


Figure 5.43 Snapshot of fluids' saturations for the life time WAG 3 months half-cycle scenario with conventional completion. Cross-section.

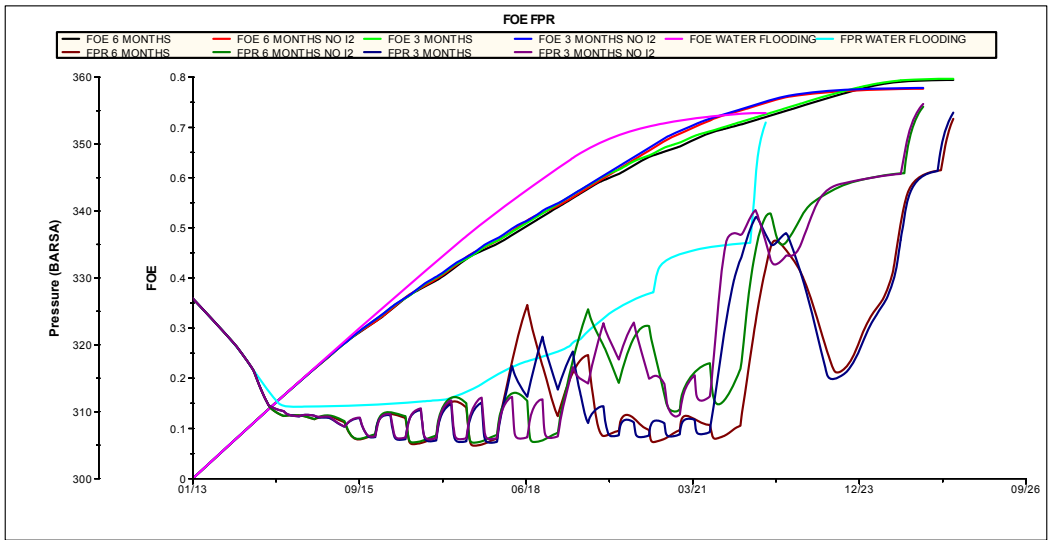


Figure 5.44 Oil recovery and pressure for changing completion WAG scenario