IMPERIAL COLLEGE LONDON

Department of Earth Science and Engineering

Centre for Petroleum Studies

Three Phase Relative Permeability Models for WAG Simulation

By

Baasir Tasleem

A report submitted in partial fulfilment of the requirements for the MSc and/or the DIC.

September 2010

DECLARATION OF OWN WORK

I declare that this thesis "**Three Phase Relative Permeability Models for WAG Simulations**" is entirely my own work and that where any material could be construed as the work of others, it is fully cited and referenced, and/or with appropriate acknowledgement given.

Signature:..

Name of student: Baasir Tasleem

Name of supervisor: Dr. Jonathan Carter

Name of the company supervisor: Marie Ann Giddins, Schlumberger

Abstract

Enhanced Oil Recovery (EOR) projects are becoming extremely important to oil companies as the conventional hydrocarbon resources are depleted. Water alternating gas (WAG) has been a renowned EOR process for more than fifty years. Fluid flow in a WAG injection process has been regarded as a complex phenomenon. This is because of the dependence of fluid flow on the saturation history. The oscillations in saturation history give rise to complex effects such as hysteresis which are more significant during three phase flow.

The hysteresis effects are generally modelled in conjunction with empirical three phase relative permeability models. Recently new empirical (Blunt, 2000) and complex pore network models (Suicmez *et al.*, 2007) have been developed that predict the lab measured data in good agreement. However the current industrial practice still utilizes the earlier developed models, namely: Stone 1 (Stone, 1970**)**, Stone 2 (Stone, 1973) and Saturated Weighted Interpolation method which is defaulted in the commercial reservoir simulator[1] (Eclipse Technical Description). The performance of these empirical models has been the centre of debate for a long time. Selection of the most suitable method and choice of parameters may be a compromise between the need to match measured physical data and the need to obtain good performance from the simulator.

In this study an attempt is made to model the hysteresis effects during an immiscible and miscible WAG flood by using different options present in a commercial compositional reservoir simulator. A comparative analysis on realistic data by using different empirical three phase relative permeability models has been performed. The results indicate that all available options present in the simulator should be utilized with history matching before deciding on which option to be used. Multiple sensitivity studies on various parameters and their effect on total oil recovery have been presented which would be helpful for an engineer to accurately manage and model the hysteresis effects in WAG simulations. Several recommendations for further studies have also been made. This work can be taken as a reference for initial test runs or pilot project studies when planning for a full field scale WAG flood.

[1] **Shall be referred as ECL default.**

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Three Phase Relative Permeability Models for WAG Simulations

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Imperial College supervisor – Dr. Jonathan Carter

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In this study an attempt is made to model the hysteresis effects during an immiscible and miscible WAG flood by using different options present in a commercial compositional reservoir simulator. A comparative analysis on realistic data by using different empirical three phase relative permeability models has been performed. The results indicate that all available options present in the simulator should be utilized with history matching before deciding on which option to be used. Multiple sensitivity studies on various parameters and their effect on total oil recovery have been presented which would be helpful for an engineer to accurately manage and model the hysteresis effects in WAG simulations. Several recommendations for further studies have also been made. This work can be taken as a reference for initial test runs or pilot project studies when planning for a full field scale WAG flood.

Introduction

Many hydrocarbon resources of the world have now passed through their primary and secondary production phases. Therefore, these reservoirs have become good candidates for application of EOR methods where it is aimed to improve the hydrocarbon recovery as much as possible. There are large varieties of EOR or tertiary recovery processes available that range from simple fluid injection combinations to complex mixtures that have been either used in a pilot test or have been implemented on full field scale studies.

WAG injection is one of the tertiary recovery processes that is used to enhance the initial estimated oil recovery. This is achieved by doing alternate water and gas injection cycles where water injection controls the macroscopic sweeping efficiency and the gas cycle increases the microscopic displacement of oil. The history of application of WAG injection dates back to 1957 (Christensen *et al*, 2001) and has been the cornerstone of all major enhanced oil recovery processes since then.

Whenever a field is considered for a tertiary recovery process, the first point of consideration is to evaluate the effectiveness of that process using simulation studies. This might be done on a full field scale model or most likely on a sector model to save computational time. The main challenges while simulating the WAG flood are the hysteresis effects that arise due to continuous saturation changes of the injection fluids in three phase flow. Largely these saturation changes affect the relative

[2] **Shall be referred as ECL default.**

permeability of the three phases which makes it necessary to model cycle dependent hysteresis effects.

There are many empirical models available for simulating cycle dependent relative permeabilities, namely: Land (Land 1968), Killough (Killough, 1972) and Carlson (Carlson, 1981). These models have been termed as simplified two phase hysteresis models (ECLIPSE Technical Description, 2010 and Larsen *et al.*, 1998) and have been regarded as inadequate to honour the physics of complex hysteresis effects in multiple displacements (Larsen *et al.*, 1998) involved in a WAG process. Moreover the performance of the three phase relative permeability models, namely: Stone1[3], Stone2[4] and ECL default, used to model the oil relative permeability in three phase flow, has been debated in the literature on many occasions. Among the three methods, Stone1 and ECL default are regarded as the most suitable methods for simulation (Blunt, 2000).

Hysteresis in three phase flow was first reported by Caudle *et al.*, (1951) during the relative permeability experiments. A decrease in relative permeability was also observed when oil saturation was decreased with the increase in gas and water saturations. It was also established that the relative permeability of each of the three phases, in this case, depends upon the saturation of the other phases present during a three phase flow. Although there were limitations in experimentally measuring the three phase relative permeability, therefore it was suggested that such an analysis shall be extremely useful in managing reservoirs with alternate water and gas flooding.

Based on the above experiments, Land established a relationship for calculating relative permeability for two and three phase flow of non wetting phase in the decreasing saturation direction. This relationship honoured the trapping of the non wetting phase as the saturation starts to decrease (imbibition) and was dependent upon the saturation history maximum achieved during the increasing saturation direction (drainage). This showed that after reversal in saturation direction, two types of gas saturation exist i.e. trapped gas saturation and free gas saturation. This relationship has been included in almost every hysteresis model since then.

Killough further developed the Land saturation history dependent model by including the hysteresis effects in wetting phase as well. A relationship was also developed for the formation of scanning curves within the envelope of the bounding curves for both capillary pressure and relative permeability (wetting/non wetting phase). Land parameter was used to establish the trapping of the non-wetting phase and parametric interpolation was used to calculate the decreasing relative permeability of the non-wetting phase based on a given parameter. For the three phase relative permeability, Stone 2 model was used to predict the three phase flow based on the relative permeability from the two phase hysteresis model.

A new model for the simulation of relative permeability hysteresis for the non wetting phase was given by Carlson. It was established that the use of a single imbibition curve is inadequate for the purpose of reservoir modelling since the decreasing relative permeability, after the saturation reversal, depends upon the saturation history maximum. Carlson model was also based on the Land parameter for the calculation of hysteresis effects in non wetting phase and required less input data as compared to Killough model.

A new methodology for simulating cycle dependent relative permeabilities especially for multiphase flow processes was developed by Larsen *et al.,* (1998). It was established that when simulating a tertiary recovery process accompanied by oscillations in saturations, especially in a WAG process, the use of standard hysteresis two phase models shall not be adequate to simulate the multiple displacements involved. This is mainly because the relative permeability of a phase depends upon the saturation history and when there are saturation oscillations the history always changes. Hence the relative permeabilities of the three phases are the functions of saturations of all the three phases, especially after a primary flood is followed by a secondary flood. In this paper models of Land, Killough, Carlson and Larsen have been used to simulate the hysteresis effects in a compositional simulator.

A comparison of the hysteresis options present in a commercial black oil simulator were presented by Kossack (Kossack, 2000). All the present established hysteresis models (Land, Killough, Carlson and Larsen *et al.*) were used on a test case (linear model) in the simulator to simulate the hysteresis in relative permeabilities and capillary pressures. An attempt was also made to simulate the WAG hysteresis based on the model presented by Larsen *et al*. (1998) in combination with the standard two phase hysteresis models. A comparison was done between the results of all the simulation models and recommendations were given to how to choose the correct hysteresis options while attempting to simulate the hysteresis effects.

In this paper, the previous work done by Kossack is extended to include simulation of hysteresis effects in a compositional simulator. Moreover a comparative study on the available three phase relative permeability models is done while simulating hysteresis effects in an immiscible and miscible WAG flood.

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[3] **Shall be referred as ST1**

[4] **Shall be referred as ST2**

Simulation Study

The work performed in this study is outlined as below:

Firstly:

- Synthetic model created by Kossack was used to generate the same results by using the black oil simulator (ECLIPSE, 2010).
- The initial results were analyzed which led to further studies on a compositional simulator.

Secondly:

- A modified model was created in a compositional simulator from the earlier work of Killough *et al*., (1987).
- This modified model was used to simulate the hysteresis effects in an immiscible and miscible WAG flood scenarios.
- The three phase relative permeability was predicted by using Stone 1, Stone 2 and ECL default methods in the simulation.
- Sensitivity analysis was also performed to identify the various parameters essential for WAG Flooding.
- Conclusions from the study were established and recommendations are made for future developments.

Hysteresis Options in Black Oil Simulator

As a first step to the study, the same input relative permeability curves (Figures C1, C2, C3 and C4)**,** as previously used by Kossack (2000), were used to regenerate all the published results. This was implemented to have a better understanding of the complex hysteresis phenomenon in relative permeabilities of the wetting and non-wetting phases. Three cases were defined to simulate WAG Hysteresis in water wet system to have different initial water (case 1) or gas (case 2) saturation in each grid block (Table B.1). This was done to visualize the generation of scanning curves in different cases. Only ECL Default was used to calculate the three phase oil relative permeability as comparative study was only performed using the compositional simulator. The detailed analysis of the results obtained is documented in Table B.2.

The options available for modelling hysteresis effects with Killough and Carlson models are represented by the EHYSTR keyword. These options used are summarized in Table 1.

Table 1: Model and Wetting Phase Choices when using EHYSTR keyword for Water-Wet Systems

Options	Models	Curve used for the wetting (water) phase
0	Carlson	Drainage curve
1	Carlson	Imbibition curve
2	Killough	Drainage curve
3	Killough	Imbibition curve
4	Killough	Hysteresis model used for both non-wetting and wetting phases.
-1	No Hysteresis	Equilibrate with drainage curve and simulate with the imbibition curve

In addition to these options there is the WAG hysteresis option which is used with the WAGHYSTR keyword. This option is based on the theory developed by Larsen. The input parameters required for the options mentioned in Table 1 (EHYSTR keyword), as per the recommendations and the data sets given in the simulator user guide[5] are the standard drainage and imbibition curves depending upon the model used.

The input relative permeability curves are changed from conventional drainage and imbibition curves to two phase and three phase curves for the wetting (water) phase when using the WAGHYSTR keyword, as shown in Figure 1.

[5] ECLIPSE Users How to Guide for Hysteresis: The Effect of Hysteresis Options in ECLIPSE, C. A. Kossack.

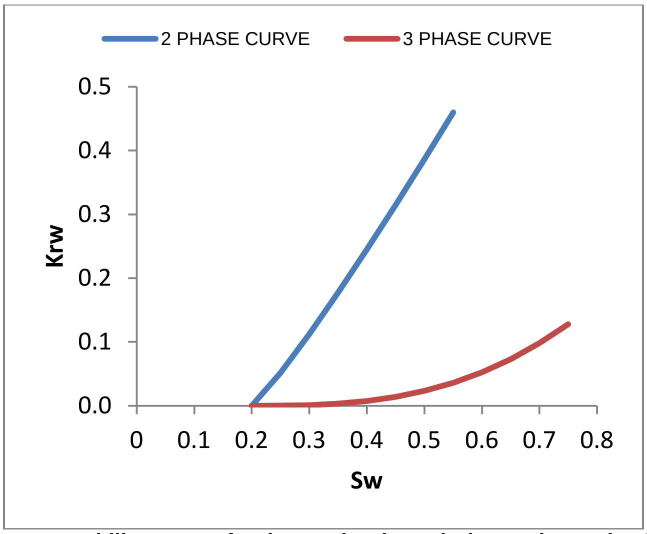

Figure 1: Input relative permeability curves for the wetting (water) phase when using WAGHYSTR keyword

The two phase curve is an input to SATNUM keyword while the three phase curve serves as an input to the IMBNUM keyword (ECLIPSE Technical Description). This means that the two phase curve in SATNUM is always above the three phase curve in IMBNUM as evident from Figure 1. While on further investigation of the data sets provided in the simulator guide, it was found that same input curves for the wetting (water) phase as shown in Figure C1 were used for simulating WAG Hysteresis as well. The input for the wetting phase when using the standard hysteresis models (EHYSTR keyword) as shown in Table 1 is the drainage and imbibition curve (Figure C1) that serves as an input to SATNUM and IMBNUM respectively. This means that the drainage curve input in SATNUM is always below the imbibition curve input in IMBNUM. Therefore, this input lowers two phase relative permeability than the three phase relative permeability for water which is contrary to the physics and requirement for simulation of WAG hysteresis.

This is further elaborated from the following figures:

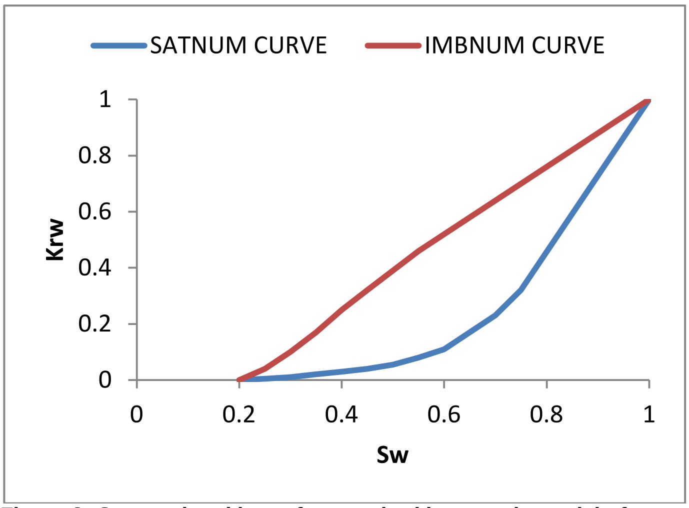

Figure 2: Conventional input for standard hysteresis model of DRAINAGE and IMBIBITION curves for the wetting phase, when using EHYTR keyword.

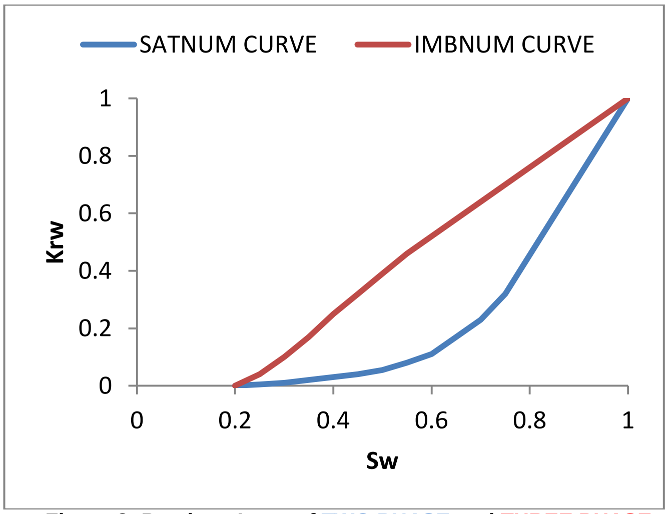

Figure 3: Previous Input of TWO PHASE and THREE PHASE curves for the wetting phase when using WAGHYSTR keyword

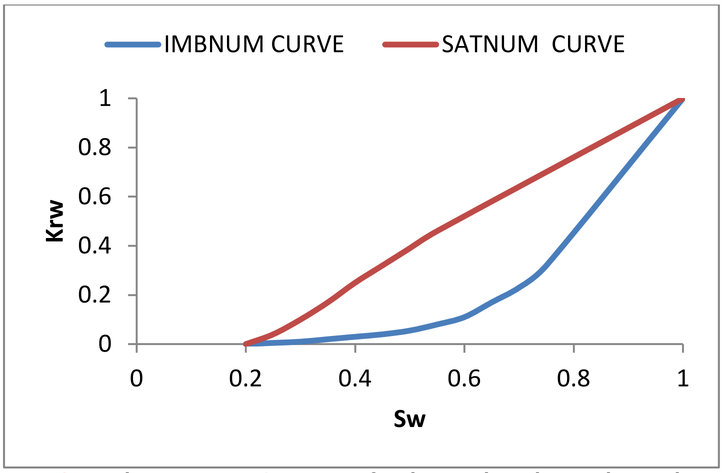

Figure 4: Modified Input of TWO PHASE and THREE PHASE curves for the wetting phase when using WAGHYSTR keyword

Therefore, the tables for input of water relative permeability should be swapped when using the WAG hysteresis option with the conventional drainage and imbibition curve.

The analysis of the results in Appendix B revealed that the standard two phase hysteresis models generated reversible scanning curves. This reversible behaviour is not experimentally observed (Spiteri *et al*, 2004). Such a reversible nature shall result in increased mobility of gas in the three phase flow which shall not predict actual results. Therefore in this work we shall consider only the WAG hysteresis option, WAGHYSTR keyword, for analyzing the three phase hysteresis effects in a compositional simulator.

WAG Hysteresis Model in Compositional Simulator

This work shall now focus on modelling the WAG hysteresis effects in a compositional simulator on the following parameters:

Table 2: Simulation Parameters for WAG injection process using WAGHYSTR keyword

WAG Simulation (WAGHYSTR) Water wet rock	
• Saturation Function	Use SWFN, SGFN, SOF3 family • Water Relative Permeability Curves ➢ Two Phase Curve ❖ Use SCAL Analysis Data ➢ Three Phase Curve ❖ Use SCAL Anaysis data, if available. ❖ Use Corey exponents and perform multiple realizations. • Gas Relative Permeability Curve ➢ Two Phase Drainage Curve ❖ Use SCAL Analysis Data • Oil Relative Permeability Curve ➢ Two phase oil relative permeability to gas (kr_{og}) and water (kr_{ow}) ❖ Use SCAL Analysis Data
• Land's Parameter (C) **(Input Parameter in WAGHYSTR)**	• Option 1 in WAGHYSTR keyword ❖ Use experimental data, if available. ❖ Perform a sensitivity analysis.
• Secondary Drainage Factor (α) **(Input Parameter in WAGHYSTR)**	• Option 2 in WAGHYSTR keyword ❖ Use experimental data, if available. ❖ Perform a sensitivity analysis.

• Three Phase Model Threshold Saturation **(Input Parameter in WAGHYSTR)**	• Option 7 in WAGHYSTR keyword ❖ The water saturation fraction above the connate water saturation at which the gas phase hysteresis shifts from two phase to three phase curve. ❖ i.e: In three Phase Curve $\mathbf{(S_w)_{cr} - S_{wc}}$
• Three Phase Oil Relative Permeability Model	Use STONE1, STONE2 an d ECLIPSE Default ❖ Analyze results of all the methods and compare it with the esablished physics of WAG
• Residual Oil Modification Fraction **(Valid only for STONE1)**	• Option 8 in WAGHYSTR keyword ❖ Use experimentally determined value, if available. ❖ Perform sensitivity analysis.
• Length of WAG Injection Cycle	• First Injection Cycle: **Gas** (Recommended) ❖ Perform sensitivity analysis.
• Timestep and Tuning	• Simulation Time Step should be kept small to honour the saturation oscillations (e.g 1 Day in this case) • Convergence issues, as experienced, might occur in finer models ❖ Use TUNING keyword. ❖ Use TSCRIT and CVCRIT keywords.

Model Description. The base model is inherited from Kossack *et al*., (1987). The inherited model was originally (3500 X 3500 X 100) feet with (7 X 7 X 3) grid blocks. One injector and one producer well were situated at the two extreme corners in diagonal direction (Figure 5). This was done in the inherited model to analyze the grid orientation effects which is out of scope of this study. Since the main focus was to evaluate the WAG hysteresis effects; the model was modified to (3500 x 1500 x 3) feet with (7 X 3 X 3) grid blocks. The wells were replaced in the same horizontal row as shown in Figure 6.

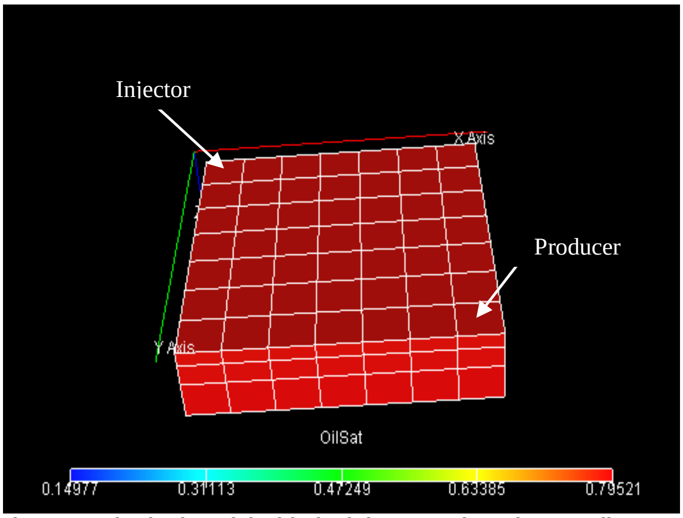

Figure 5: Inherited model with the injector and producer wells placed in the two corners of the model.

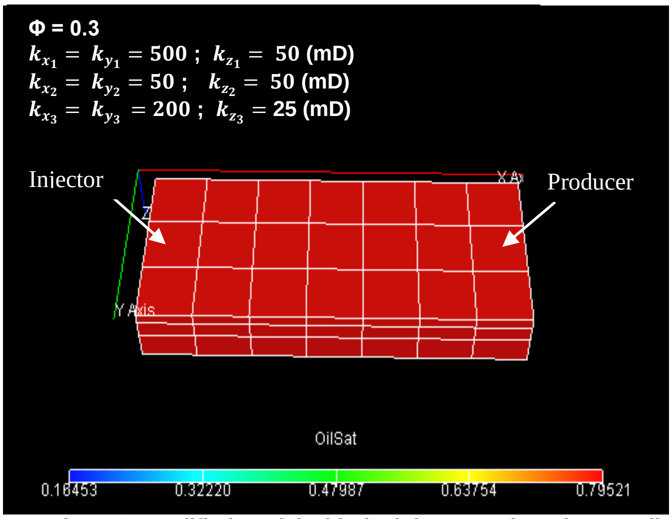

Figure 6: Modified model with the injector and producer well replaced in the same horizontal row.

WAG Hysteresis Input Curves. The input curves for the WAG Hysteresis option are different for wetting (water) phase (Figure 1). The three phase curve represents water relative permeability after an initial gas flood. The measurement of three phase relative permeability is not a regular practice as evident from literature review as well. So, for this study the three phase curve was generated by applying Corey Exponents (Figure 7) on the 2 phase drainage curve used in the previous analysis.

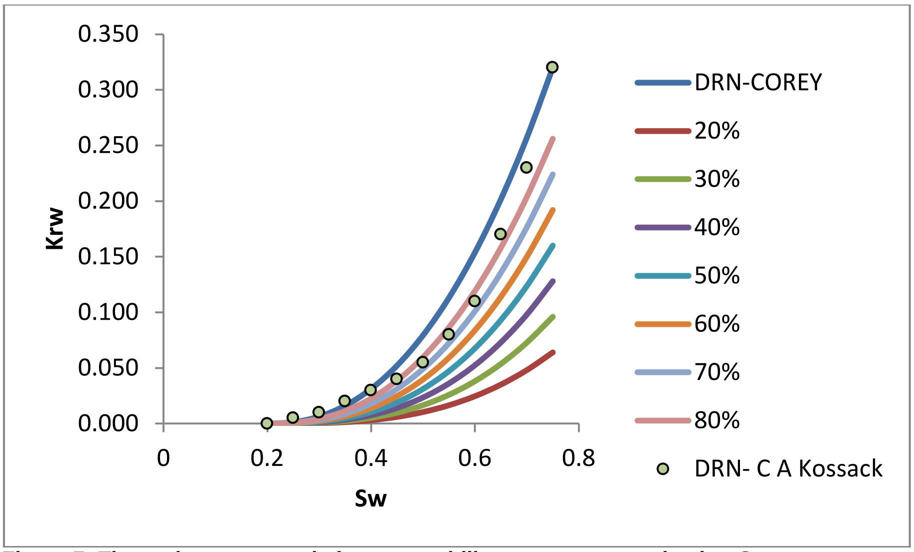

Figure 7: Three phase water relative permeability curve generated using Corey exponents

For this study, 40% curve was chosen for the input as three phase curve. The two phase curve was chosen as the water imbibition curve (Figure C1) which was used for the previous analysis. Therefore, the two phase and three phase curves used for the wetting (water) phase as input, when using the WAGHYSTR keyword, are shown in Figure 8.

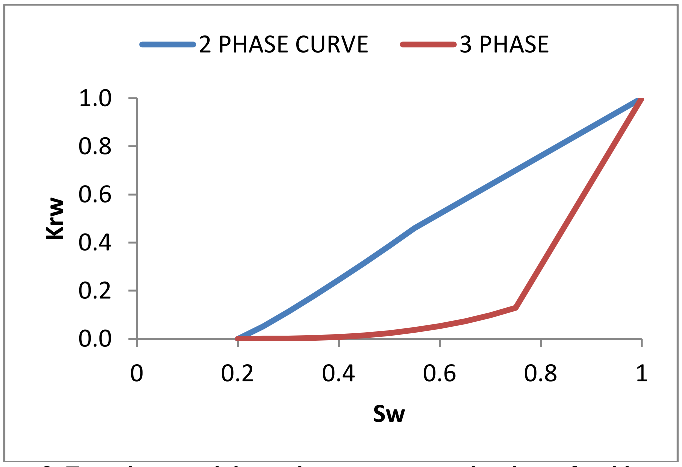

Figure 8: Two phase and three phase curves used as input for this study.

For the non wetting phase, only drainage curve is required as the input for the WAG hysteresis model. A secondary drainage curve is followed (Figure 9) as the gas saturation increases and the water saturation increases the critical saturation in the three phase curve (option 7 in WAGHYSTR keyword).

The trapping of gas is calculated from the following equation (ECLIPSE Technical Description):

$$S_{g_{trap}} = S_{g_{cr}} + \frac{\left(S_{g_m} - S_{g_{cr}}\right)}{1 + C \times \left(S_{g_m} - S_{g_{cr}}\right)}$$

The gas relative permeability on the scanning curve is calculated as:

$$k_{rg}\left(S_g\right) = k_{rg}{}^{drain}\left(S_{gf}\right)$$

Where:

$$S_{gf} = S_{g_{cr}} + \frac{1}{2}\left\{\left(S_g - S_{g_{trap}}\right) + \sqrt{\left(S_g - S_{g_{trap}}\right)^2 + \frac{4}{C}\left(S_g - S_{g_{trap}}\right)}\right\}$$

And the secondary drainage curve is calculated using the following equation:

$$k_{rg}{}^{drain} = \left[k_{rg}{}^{input} - k_{rg}{}^{input}\left(S_g{}^{start}\right)\right] \times \left[\frac{S_{w_{co}}}{S_w{}^{start}}\right]^{\alpha} + \left[k_{rg}{}^{imb}\left(S_g{}^{start}\right)\right]$$

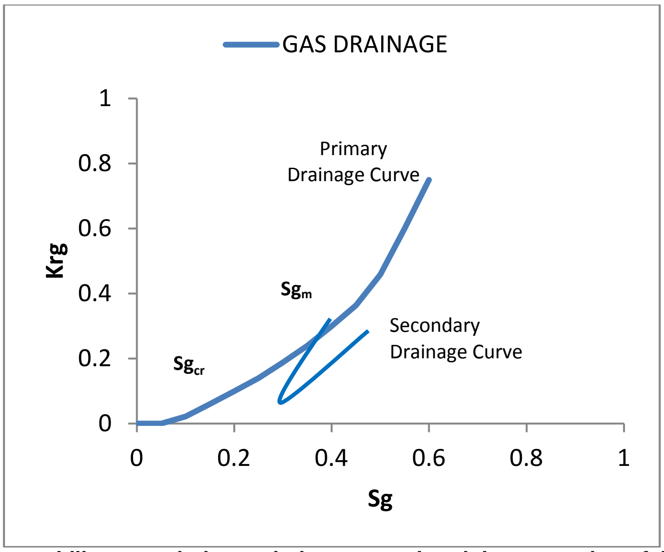

Figure 1: Input gas relative permeability curve (primary drainage curve) and the generation of the secondary drainage curve.

Immiscible WAG (IWAG) Simulation Results. The fluid model was inherited from Killough *et al.*, 1987. The initial pressure used was 2280 psi which is below the bubble point pressure of 2300 psi. The reservoir was initially produced for two years on primary production. The initial primary production was followed by eighteen WAG (each phase) injection cycles which were injected in an eighteen years with one water and one gas cycle being injected for half a year. The same gas stream (Kiilough *et* al., 1987) used for injection consists of three components: C1 (77%), C2 (20%) and C3 (3%). After the long injection period, the reservoir was allowed to deplete for two years on primary production. Hence the total time period for simulation was 22 years.

Accordingly, the injection was controlled by surface rates with water being injected at 5000 STB/Day and gas injection being 3000 MSCF/Day. The production was controlled by producing 5000 STB/Day of reservoir volume. High reservoir volume of production was selected initially in order to have a water breakthrough around the middle of the simulation time period. The three empirical methods that are available in the compositional simulator are ST1, ST2 and ECL Default. They were used for the comparative study of the three phase relative permeability for all the phases.

Figures C5, C6 and C7 represent plots of behaviour of water relative permeability for a particular grid block (4 2 1) verses saturation of that grid block. This grid block was selected as it is nearly in the middle top layer of the model and shall not have abrupt effects of flow behaviour as found near the injector grid block. The 2 phase curve and the 3 phase curve have been plotted as the bounding curves to analyze the shift from one curve to the other as predicted by ECL, ST 1 and ST 2. It is evident (Figures C5, C6 and C7) that the behaviour of ECL and ST 1 are very much alike. Although ECL model uses saturated weighted interpolation which is superior to Stone model (Blunt, 2000), the residual oil modification in ST 1 makes its predictions closer to ECL. The water relative permeability shows an instant shift from 2 phase curve towards the 3 phase curve. This is as expected because the reservoir is initially below the bubble point and the primary production for two years allows more solution gas to evolve. However, in comparison to the three models used, ST 2 shows a lesser inclination towards the three phase curve.

This is further justified by plot of the water relative permeability for the grid block (4, 2, 1) verses time predicted by the three methods. The behaviour predicted by ST 1 and ECL (Figure 10) reveals a late water breakthrough in the grid block as compared to ST 2 (Figure 11). The initial rising trend in water relative permeability is predicted by ECL and ST 1 (Figure 10) around 3000 days and reaches maximum around 5000 days while ST 2 (Figure 11) predicts the same trend around 2000 days and reaches a maximum around 4000 days. After the maximum is reached ECL and ST1 predict a steeper yet smoother declining trend as the grid block volume gets filled with water (Figure 10) hence the relative permeability trend starts to decline. While ST2 shows a sharp declining trend in the water permeability around 5400 days and then rises up and down as shown in Figure 11.

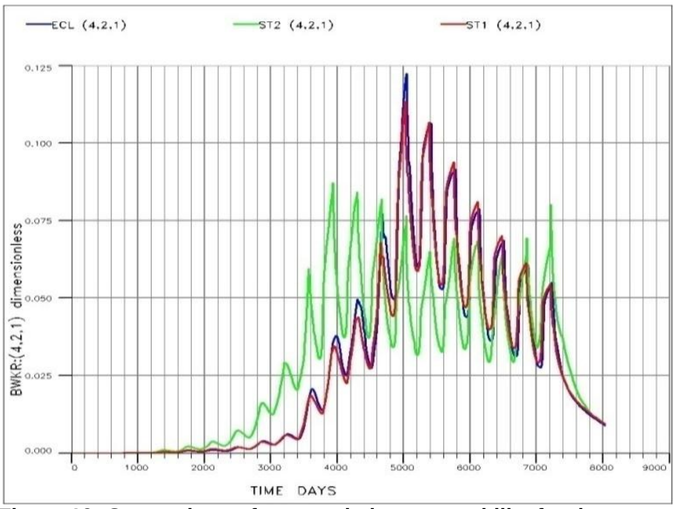

Figure 10: Comparison of water relative permeability for the grid block (4, 2, 1) VS Time

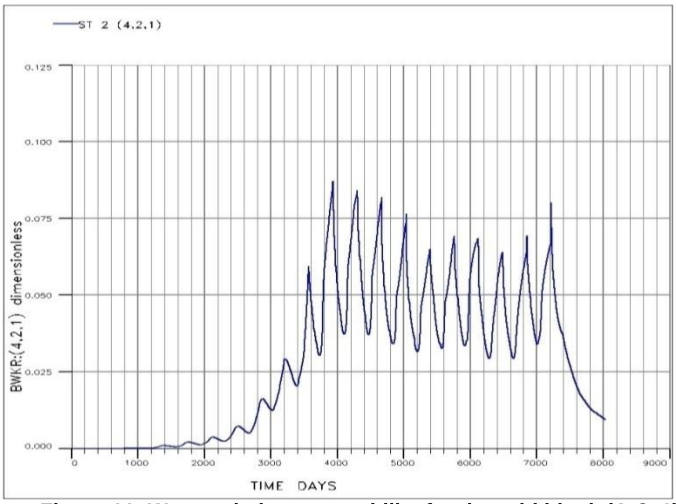

Figure 11: Water relative permeability for the grid block (4, 2, 1) VS Time predicted by ST2

The steep yet smooth declining trend in relative permeability of ECL and ST 1 is associated with the steep rising trend in water saturation of the grid block around 5000 days and after that remains stable (Figure 12) while a smooth rising trend in water saturation is predicted by ST 2 (Figure 13). It appears from the corresponding plots that a stable movement of the water front is predicted by ECL and ST 1 while the stability of the water front is not achieved by ST 2.

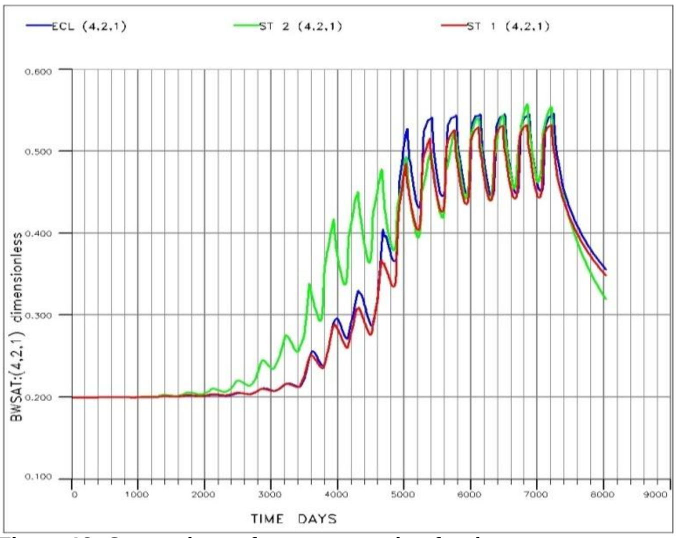

Figure 12: Comparison of water saturation for the grid block (4, 2, 1) VS Time

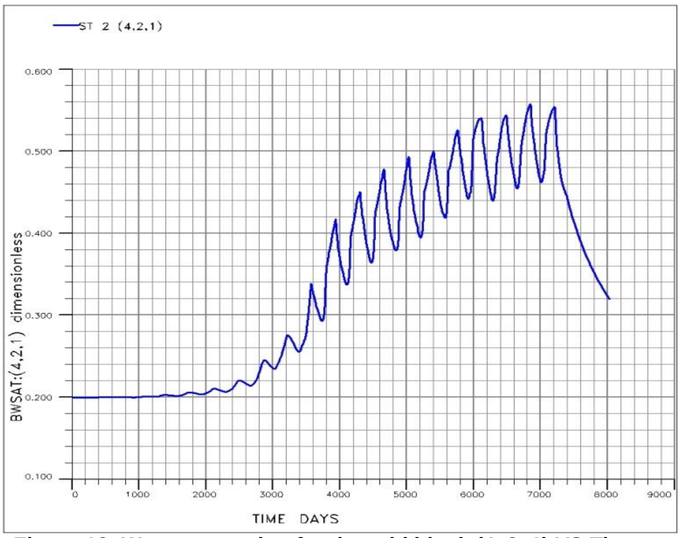

Figure 13: Water saturation for the grid block (4, 2, 1) VS Time predicted by ST2

Figures 14 and 15 shows the same comparison of the models in the prediction of the oil relative permeability for the grid block (4, 2, 1). The oil relative permeability predicted by ST1 and ECL results in a gradual decreasing trend after 3000 days as the water breaks through in the grid block (Figure 10). The predictions of ST 2 reveal firstly a stable decreasing trend in oil relative permeability after 2000 days till 3400 days and after that a sharp declining trend in oil relative permeability is observed (Figure 15). This corresponds to the initial increasing trend in water relative permeability (Figure 11) after 2000 days and a sharp increasing trend after 3400 days. However, ECL and ST1 predict a sharp declining trend in the oil relative permeability (Figure 14) around 5000 days which corresponds to the maximum water relative permeability achieved as shown in Figure 10.

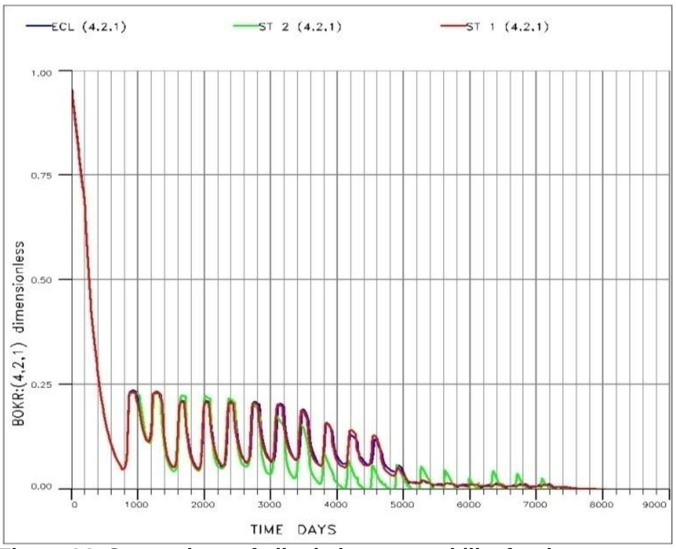

Figure 14: Comparison of oil relative permeability for the grid block (4, 2, 1) VS Time

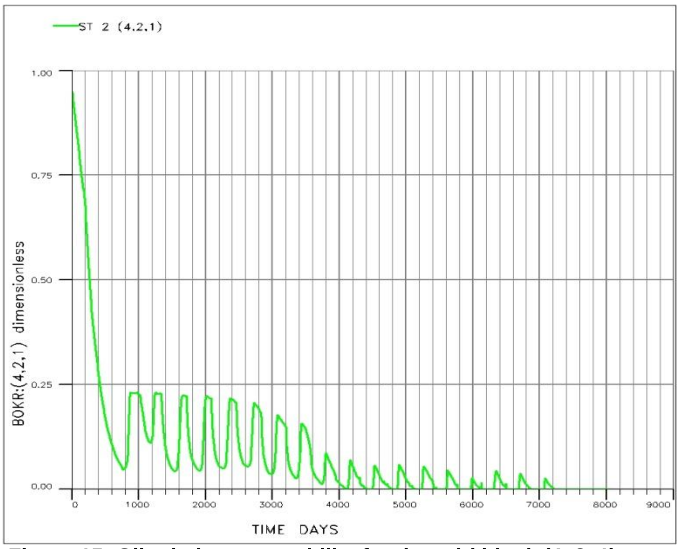

Figure 15: Oil relative permeability for the grid block (4, 2, 1) VS Time predicted by ST2

ECL lowers down to residual oil saturation (Sor = 0.2) earliest while ST1 stays slightly above in parallel to ECL (Figure 16). But the relative permeability predicted by both methods is the same at different saturations. This might be the point where the saturation modification in ST 1 gives increased oil saturation due to the trapping of gas. However, the oil saturation predicted by ST 2 (Figure 17) shows a sharp declining trend around 3400 days. After that it declines smoothly and reaches Sor around 6500 days. This is expected as higher remaining oil is predicted by ST2. This reveals the movement of unswept volumes of oil along with the water front. Therefore, ST 2 also predicts the increase in oil relative permeability at lower oil saturations due to gas trapping which is one of the main features of WAG. This is in agreement to the work of Larsen *et al.*,(1998) in which a modification is done to the residual oil saturation to couple the trapped gas saturation in ST 1.

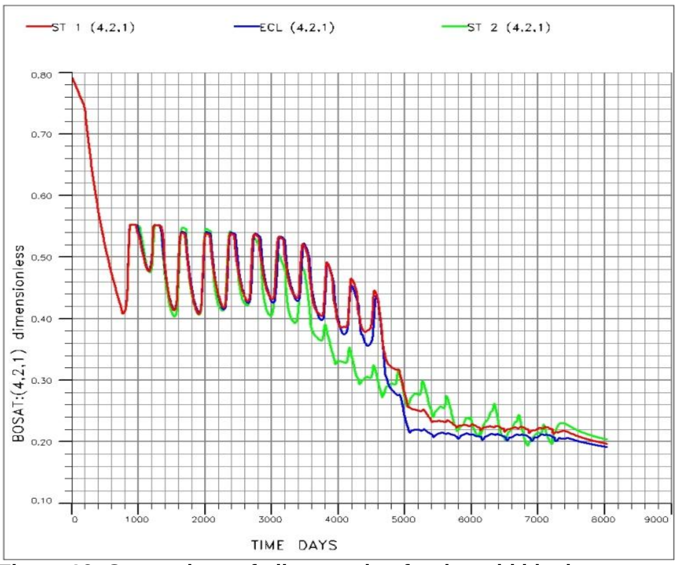

Figure 16: Comparison of oil saturation for the grid block (4, 2, 1) VS Time

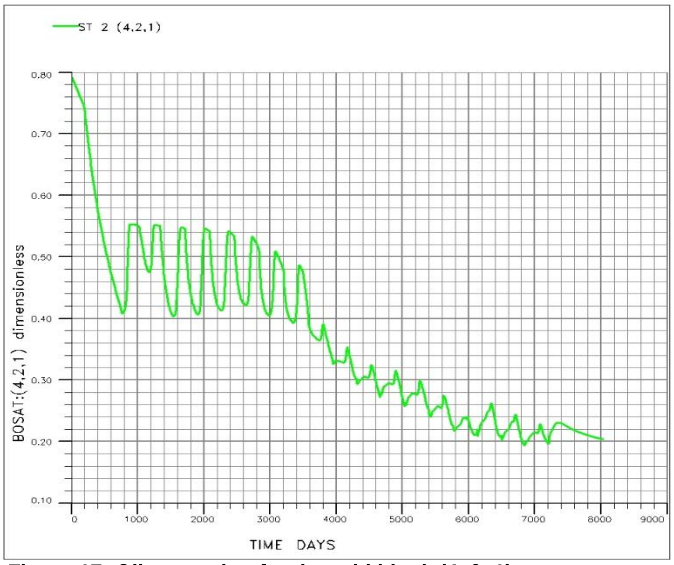

Figure 17: Oil saturation for the grid block (4, 2, 1) VS Time predicted by ST2

However, the prediction of the gas relative permeability, by all three methods, for the block (4, 2, 1) (or any other block) is almost the same as shown in Figure C8. This is mainly because that the mobility of gas is controlled by the water saturation threshold above the connate water saturation value (Option 7 in WAGHYSTR keyword) from which the two phase model shifts to the three phase model and follows a secondary drainage process and the secondary drainage factor (Option 2 in WAGHYSTR keyword). This threshold must be a user defined value depending upon the critical water saturation in the three phase water relative permeability input curve.

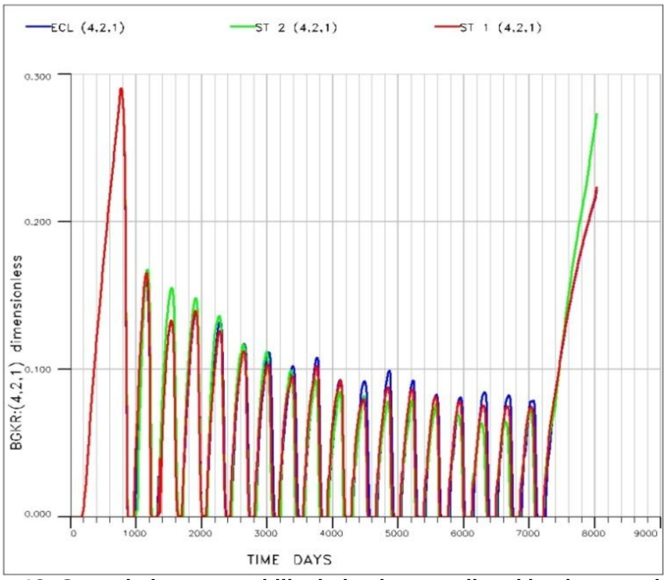

Figure 18: Gas relative permeability behaviour predicted by three methods.

The initial rise in the gas relative permeability is due to the production of the solution gas for the first two years of primary production. The first gas injection cycle, followed after the first water cycle, takes place around 900 days but instead of increasing relative permeability a reduction takes place Figure 18. This is because the gas gets trapped in the grid block (Figure 20) and hence reduces the relative permeability (Larsen *et al.*, 1998). The decrease in saturation around 1000 days (Figure 19) corresponds to the lower volume of free gas at that time in the grid block. As the second gas cycle is injected around 1200 days the saturation of the free gas increases in the grid block. At the end of each gas cycle the gas saturation returns to the trapped saturation and then increases with the injection cycle accordingly as shown in Figures 19 and 20 which shows that the trapped gas saturation does not contribute to the flow of free gas (Larsen *et al.*, 1998).

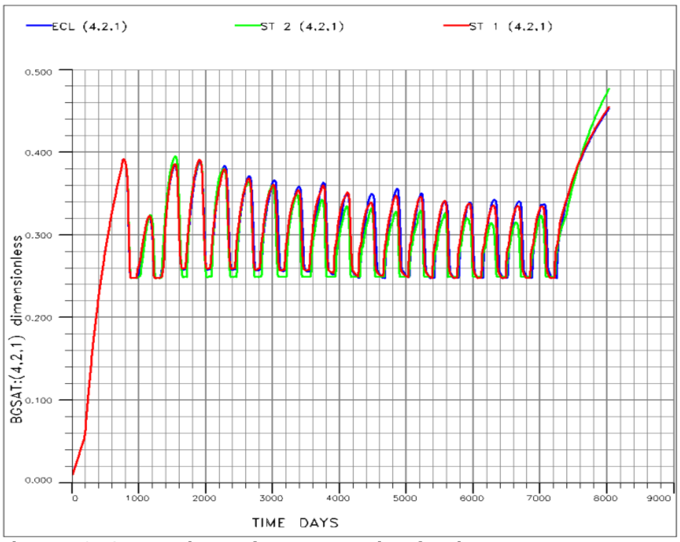

Figure 19: Comparison of gas saturation for the grid block (4, 2, 1) VS Time.

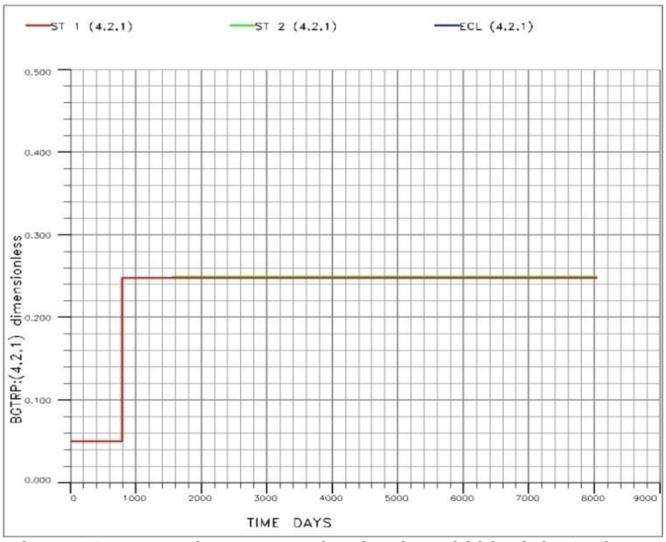

Figure 20: Trapped gas saturation for the grid block (4, 2, 1) VS Time predicted by three methods used.

Accordingly since early water breakthrough is predicted by ST 2 in the grid block, this effect can also be seen on a field scale (Figure 21). This ultimately results in less oil recovery (Figure 22) when compared with ECL and ST1 but less gas production (Figure 23) is predicted by ST2 when compared with the other two.

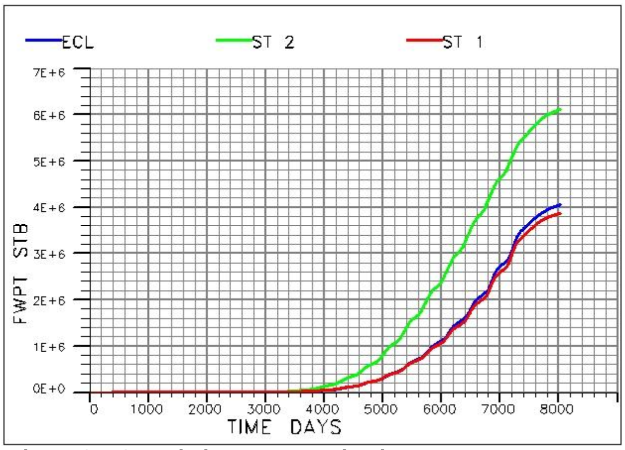

Figure 21: Cumulative water production

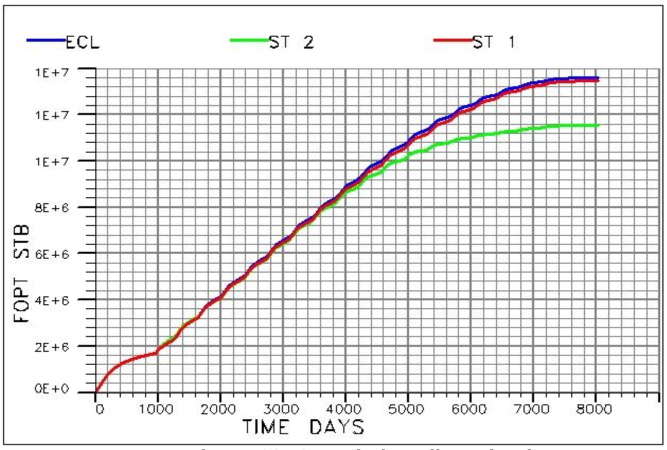

Figure 22: Cumulative oil production

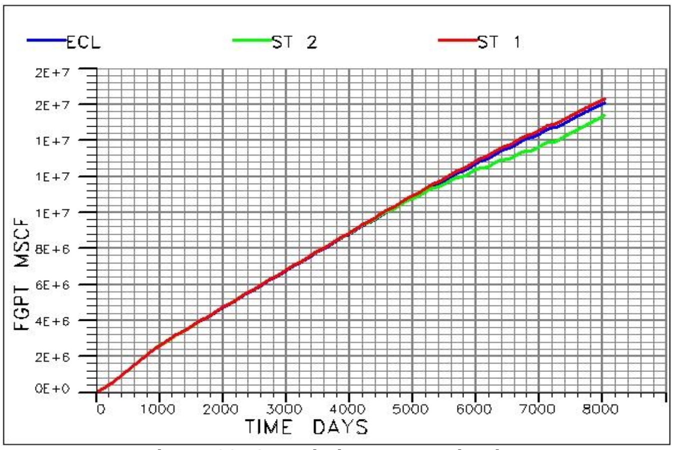

Figure 23: Cumulative gas production

Miscible WAG (MWAG) Simulation Results. An attempt was made to simulate a miscible WAG flood. This was achieved by increasing the initial reservoir pressure to 5000 psi. The results of a previous study of the given gas stream indicated FCM to be around 3870 psi and MCM to be around 3220 psi. Hence by having a high initial pressure it was made sure that miscibility is achieved for almost whole of the simulation time period. Injection of WAG was done from the start and the production rate was lowered to 3500 STB/DAY otherwise it would have been difficult to maintain miscibility. The same injection gas stream was used form the previous analysis. The simulation time period was kept the same (22 years) with 4 years of natural production after 18 years of initial injection period.

The MWAG process was analyzed with a single method ST 2. Figure 25 represents the pressure of the grid block (4, 2, 1). It can be seen that the block pressure is maintained above the MCM pressure throughout the simulation. The relative permeabilities of all the phases correspond to the trend in respective saturations. The fluctuating trends in relative permeabilities and saturations between 3500 days and 5000 days show the phase exchange behaviour between the injected gas and oil before the formation of a single hydrocarbon phase (Figure 24 and 26). As miscibility is achieved in the grid block the oil saturation goes to zero with the surface tension (Figure 24) around 5200 days**.** Therefore, there are two phases, water and hydrocarbon phase, in the grid block. The trapped gas fraction increases as more hydrocarbon phase is formed. Therefore, as the miscible front advances in the reservoir, the initial formation of the hydrocarbon phase shall result in increased mobility (Figure 27) which is observed after miscibility is achieved. Hence, three phase flow behaviour is not dominant when considering a MWAG process.

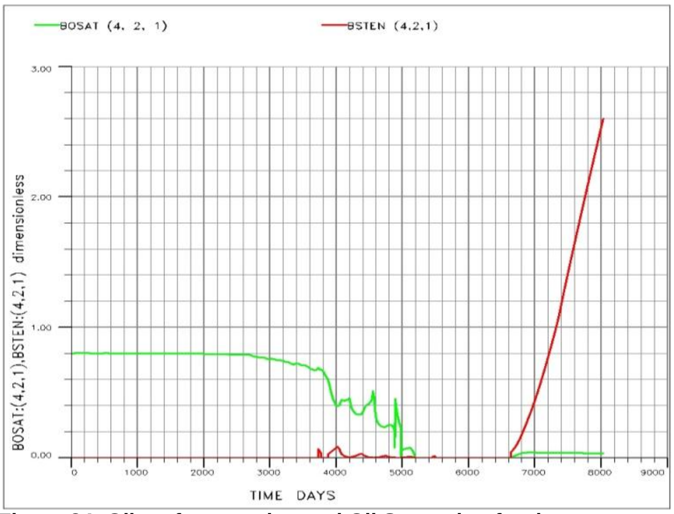

Figure 24: Oil surface tension and Oil Saturation for the grid block (4, 2, 1) VS Time

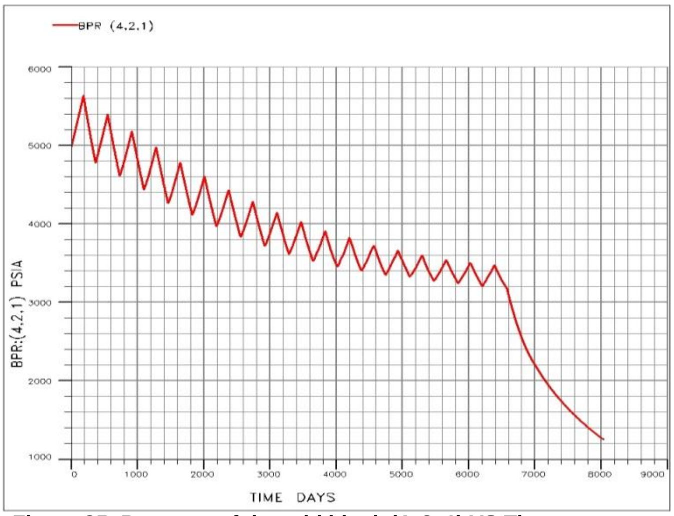

Figure 25: Pressure of the grid block (4, 2, 1) VS Time

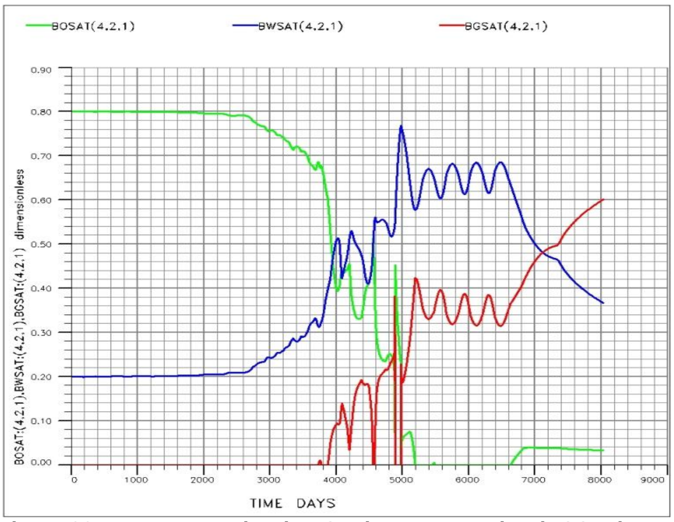

Figure 26: Water saturation (BWSAT), gas saturation (BGSAT) and Oil Saturation (BOSAT) for the grid block (4, 2, 1) VS Time for the grid block (4, 2, 1) VS Time

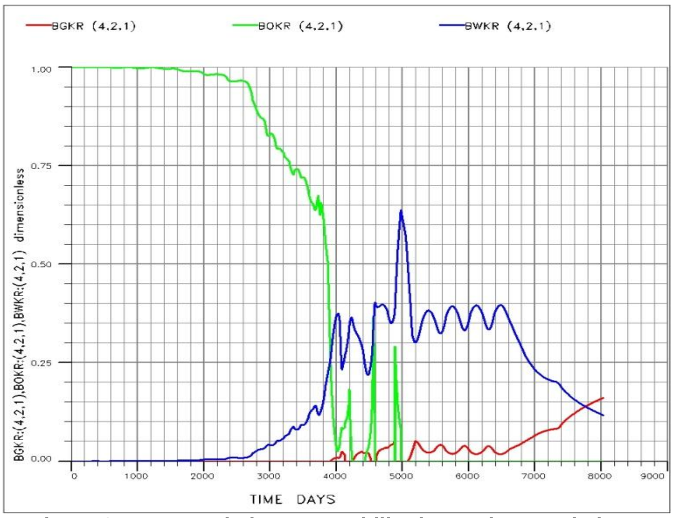

Figure 27: Water relative permeability (BWKR), gas relative permeability (BGKR) and oil relative permeability (BOKR) for the grid block (4, 2, 1) VS Time

Sensitivity Analysis

While simulating a WAG flood, some of the options were varied in order to evaluate their impact on the oil recovery. They are:

- Land Parameter.
- Secondary Drainage Factor.
- Length of water and gas cycles

For the sensitivity analysis of the IWAG and MWAG processes, only Stone 2 was used. Land parameter and secondary drainage factor are more dominant during IWAG process so their impact was not analyzed for the MWAG process.

Land Parameter. This parameter refers to the trapping of gas during two phase and three phase flow. The greater the value of this parameter the lesser would be the gas trapped as shown in Figure 28. Low gas entrapment shall lead to lesser oil entrapment in the form of layers or isolated patches which can then be swept away by water. Therefore more oil can be swept with more gas entrapment leading to quick oil recovery. This can be seen in Figure 29 as the cumulative oil recovery is approximately same but slightly quicker but for Land_1 than Land_50. But caution should be taken while specifying high values of Land parameter as it shall cause a steep imbibition curve that may lead to convergence issues **(ECLIPSE Technical Description)**.

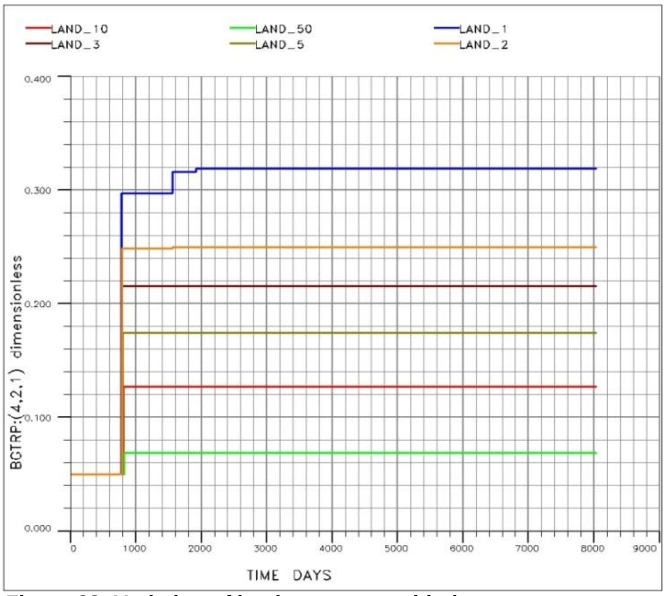

Figure 28: Variation of land parameter with time

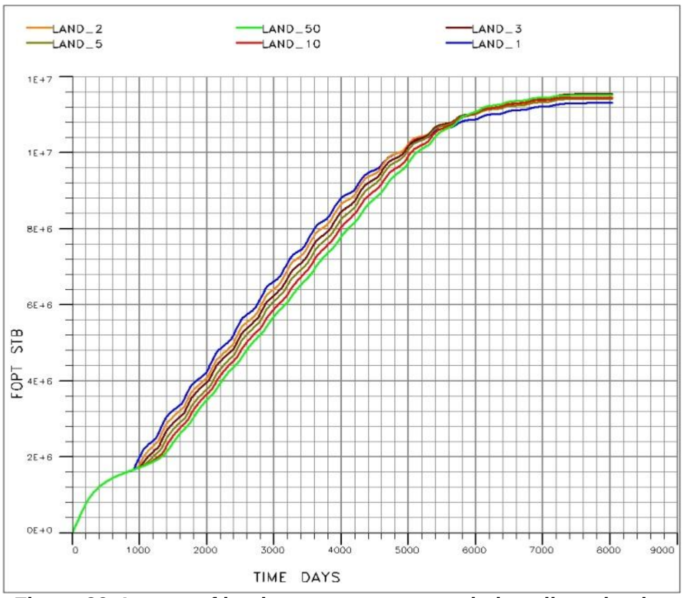

Figure 29: Impact of land parameter on cumulative oil production

Secondary Drainage Factor. This parameter refers to the reduction in gas mobility (Figure 30) once the secondary drainage takes place. It seems to be insensitive to the total oil production as shown in Figure 31. This is because, in this study, the model utilized is fully homogenous and the gas front moves only in the top layer.

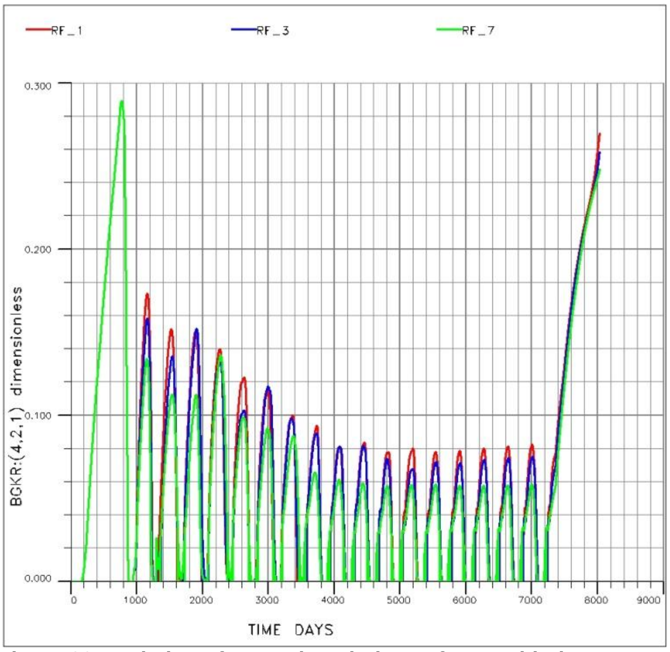

Figure 30: Variation of secondary drainage factor with time

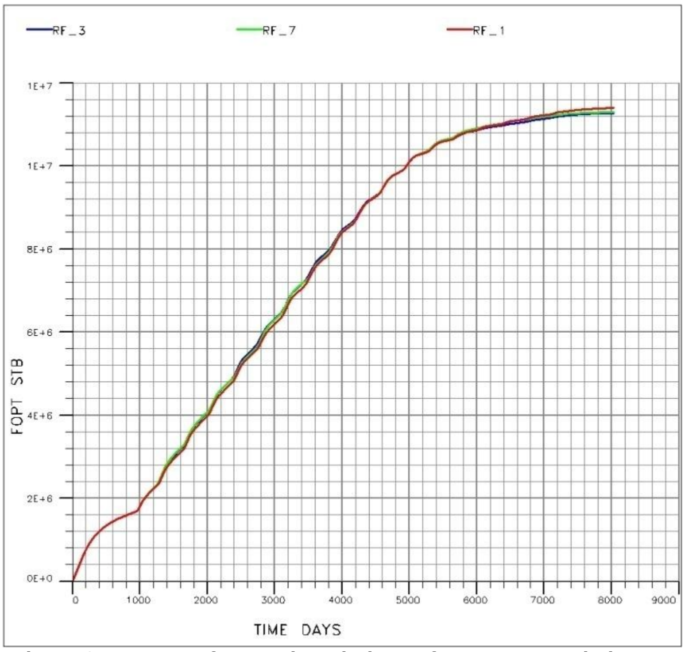

Figure 31: Impact of secondary drainage factor on cumulative oil production

Length of Water and Gas Cycles. This is one of the governing factors that not only effect total oil recovery but also the economic aspects as well. Different combinations can be run to have an in depth analyses of the impact of the slug size on the concerned reservoir. Table 3 shows a comparison between different combinations of injection cycles and differences in oil recovery if hysteresis is not considered in an immiscible WAG process.

IWAG Sensitivity Analysis. Table 3 shows a comparison between different combinations of injection cycles and differences in oil recovery if hysteresis is not considered in an immiscible WAG process. These combinations were used to analyze the impact on cumulative oil recovery when using the WAGHYSTR keyword, EHYSTR keyword (Option 8: Jargon's method for Compositional simulator) and with no hysteresis. The FOOIP was 17 MMSTB and the injection period was 18 years.

Table 3: IWAG sensitivity analysis for WAGHYSTR keyword, EHYSTR keyword and with no hysteresis. The percentages represent the total oil recovery in each case

	FIRST INJECTION CYCLE	1:4	1:2	1:1	2:1	4:1
WAGHYSTER	WATER	51%	63%	65%	66%	66%
	GAS	50%	62%	65%	69%	69%
NO HYSTERESIS	WATER	47%	60%	61%	62%	61%
	GAS	44%	59%	62%	62%	61%
EHYSTR (OPTION 8)	WATER	43%	44%	43%	44%	43%
	GAS	43%	44%	43%	44%	44%

It is evident from the above analysis that hysteresis should be taken into account otherwise the interpretations might be misleading. Also, it is preferred to have gas injection first in the ratio of 2:1 as it gets trapped in the oil and then with the subsequent water cycle sweeps it away. For this study the optimized WAG cycle is in the ratio of 2:1 with gas injection cycle being twice in length than the water cycle. Since the model in this study is very coarse therefore more than 2 cycles of gas and water injection do not result in further increased recovery. This is because the gas front sweeps the top most layer while water font sweeps the other two layers efficiently and both travel as pulses throughout the injection period.

Since the input for WAGHYSTR keyword and EHYSTR keyword are different, therefore two phase and three phase curves were used as drainage and imbibition curves for input of the wetting phase while the previous drainage and imbibition curves were used (from the analysis using the black oil simulator) as input for the non-wetting phase.

MWAG Sensitivity Analysis. In the MWAG processes it is necessary to keep the reservoir pressure above the MCM pressure. This can result in unrealistic high well pressure values for some cases because the gas injection was done from start. In this analysis such values were restricted and only those cases are presented in which reservoir pressure did not experience an exponential rise in pressure from the first day of injection. The FOOIP was 18.5 MMSTB and the injection period was 18 years. The increased FOOIP is due to the reason that initial pressure of the reservoir is above the bubble point.

Table 4: MWAG sensitivity analysis for WAGHYSTR keyword and with no hysteresis. The percentages represent the total oil recovery in each case

	FIRST INJECTION CYCLE	1:4	1:2	1:1	2:1	4:1
WAGHYSTR	WATER	58%	72%	83%	--	--
	GAS	--	--	82%	--	--
NO HYSTERESIS	WATER	55%	--	81%	--	--
	GAS	53%	67%	81%	68%	--

The results in Table 4 show that, in this study, the optimized length of MWAG injection cycle is in the ratio of 1:1 with either water or gas being injected first. This is because that miscibility throughout the simulation time period is only maintained in the ratio of 1:1. In other cases the reservoir pressure drops below the MCM pressure which leads to less oil recovery. The total recovery of the heavier components of oil (C10, C15 and C20) also indicated that the fluid recovered consists of the liquid components and the increased recovery is not due to the swelling of oil but due to miscibility.

Discussion

Black Oil Simulation. The initial study established that WAG Hysteresis can be accurately modelled in the black oil simulator when modified input curves are used. However, in this case, the use of the WAG Hysteresis model (WAGHYSTR keyword) with standard two phase hysteresis models (EHYSTR keyword) resulted in higher gas mobility. This was not the case when same cases were simulated with only WAG Hysteresis model. However, hysteresis behaviour in the oil phase was insensitive to the option used.

IWAG Simulation. The comparative study of the empirical three phase relative permeability models show that ST 1 with the oil modification factor predicts the behaviour in agreement with ECL Default. The predictions of ST2 result in total oil recovery which is less when compared with the other two models. However, ST 2 also predicts increased oil relative permeability at lower oil saturations. The sensitivity analysis shows that the total oil recovery is insensitive to variations in the Land parameter and secondary drainage factor. However, the rate of recovery might be increased with the increasing trapping and reduction of gas mobility. The length of the injection cycles can be an essential parameter to optimize the total oil production and the economics of the process.

MWAG Simulation. The MWAG simulations showed that as miscibility is achieved in the reservoir, two phase flow behaviour is dominant. The sensitivity analysis resulted in increased total oil recoveries with less injection of water and gas. However, to maintain pressure above the MCM for the whole production time period may not be feasible. As the pressure reduces, three phase flow behaviour can be observed similar to the immiscible case.

For a full field study, it is possible that different hysteresis behaviour may occur in different areas of the reservoir. The present options in the simulator do not allow for the simulation of simultaneous two phase and three phase hysteresis in separate regions.

Conclusions and Recommendations for Future Research

In this work, hysteresis effects have been modelled in WAG simulation and multiple sensitivity studies on various parameters and their effect on total oil recovery have been presented. From this study we conclude:

- The WAG hysteresis model is effective for presenting the effects of gas trapping in a WAG flood.
- For the models used in this study, the effect of combining the standard two phase hysteresis models with WAG Hysteresis model was not significant.
- Multiple realizations can be created for future studies by selecting different reduced water relative permeabilities to be input as the three phase curve when using the WAGHYSTR keyword.
- In this study the cumulative oil recovery was insensitive to variation of the Land parameter and secondary drainage factor.
- Three phase hysteresis effects are not dominant in the MWAG process. Higher oil recoveries due to increased trapped gas fraction and miscibility with equal volumes of injection phases were observed in this study. Further detailed analysis can be performed by using different two phase hysteresis models.
- Provisions should be made in the simulator to model two phase and three phase hysteresis in different regions. This shall help in modelling miscible and immiscible regions in MWAG process.
- Further study is required by developing a fine scale model to quantify the physical and numerical dispersion effects along with visualizing the frontal advancement.
- More studies in simulating the hysteresis effects in an oil-wet or a mixed-wet system are required. The recently developed complex three phase pore network models that predict lab data in good agreement for all wettability conditions may be used for this purpose.
- Selection of options available for the empirical three phase relative permeability models, in conjunction with the options available for hysteresis can depend on data and processes considered in the study. Detailed analysis with history matching should be performed before any specific method is selected.
- Considering options in available to model the hysteresis effects, multiple sensitivity analysis with multiple combinations can be performed to analyze the impact on the cumulative oil recovery.

Nomenclature

BGKR	Block Gas Relative Permeability
BGSAT	Block Gas Saturation
BGTRP	Block Gas Trapped Saturation
BPR	Block Pressure
BOKR	Block Oil Relative Permeability
BOSAT	Block Oil Saturation
BSTEN	Block Surface Tension
BWKR	Block Water Relative Permeability
BWSAT	Block Water Saturation
krg	Relative Permeability of gas
FCM	First Contact Miscible
FGPT	Total Field Gas Production
FOPT	Total Field Oil Production
FWPT	Total Field Water Production
Krw	Relative Permeability of water
krog	Relative Permeability of oil in gas
krow	Relative Permeability of oil in water
MCM	Multi Contact Miscible
MSCF	Million Standard Cubic Feet
psi	Pressure per square inch
SCAL	Special Core Analysis
Sg	Saturation of gas
So	Saturation of oil
Sor	Residual Oil Saturation
Sw	Saturation of Water
$(S_w)_{cr}$	Critical Water Saturation
S_{wc}	Connate Water Saturation
STB	Stock Tank Barrel
FOOIP	Field Oil Originally In Place

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APPENDIX A

Critical Literature Review

SPE Paper	Year	Title	Authors	Contribution
951145-G	1951	"Further Developments in the Laboratory Determination of Relative Permeability"	Caudle, B. H., Slobod R.L., E. R. Brownscombe	First to observe hysteresis during the relative permeability experiments.
1942	1968	"Calculation of Imbibition Relative Permeability for Two and Three-Phase Flow from Rock Properties"	Land, C. L	First to establish a relationship for calculating the trapping of gas saturation during the decrease in relative permeability after reaching the saturation history maximum in the increasing saturation direction.
5106	1974	"Reservoir simulation with History Dependent Saturation Functions"	Killough, J. E.	A new model for the calculation of the saturation history dependent relative permeabilities and capillary pressure for the wetting and the non wetting phases.
10157	1981	"Simulation of Relative Permeability Hysteresis to the Non-wetting Phase."	Carlson, F. M.	A new model for the calculation of imbibition relative permeability hysteresis was formulated.
20183	1990	Three-Phase Relative Permeability	Oak, M. J.	1. First to completely measure three phase relative permeability data on water-wet Berea sandstone 2. First to compare models of Stone with the lab measured data.
38456	1997	Methodology for Numerical Simulation with Cycle-Dependent Relative Permeabilities	Larsen, J. A. Skauge, Arne.	WAG hysteresis is a complex phenomenon that cannot be modelled with the standard two phase reversible hysteresis models.
63147	2000	Comparison of Reservoir Simulation Hysteresis Options	Kossack, C. A.	First to compare the hysteresis options present in a simulator to simulate WAG hysteresis.
67950	2000	An Empirical Model for Three Phase Relative Permeability	Blunt, M. J.	First to present saturation weighted interpolation method that, accounts for the trapping of non wetting phase and oil layer drainage, predicts Oak experimental data accurately.
89921	2004	Impact of Relative Permeability Hysteresis on the Numerical Simulation of WAG Injection	Elizabeth J. Spiteri, Ruben Juanes	First to compare the standard two phase hysteresis models with lab measured data of Oak.

SPE 951145-G (1951)

Further Developments in the Laboratory Determination of Relative Permeability

Author: Caudle, B. H., Slobod R.L., and E. R. Brownscombe

Contribution to the understanding of three phase relative permeability models for WAG injections:
First to observe hysteresis during the relative permeability experiments.

Objective of the paper:
To present further developments in the laboratory determination of relative permeability.

Methodology used:
Experimental techniques for obtaining two phase relative permeability data in the presence of solution gas, to describe the mechanism of fluid flow through porous media and preliminary results for measuring three phase relative permeability.

Conclusion reached:

1. The complete measurement of two phase relative permeability in the presence of solution gas by using dynamic displacement methods.
2. In this case the relative permeability of three phases was found to be dependent upon all the three phases.
3. Hysteresis was observed to be a contributing factor, especially during three phase flow.

Comments:
Hysteresis was first time reported in a preliminary laboratory experiment. Although there were limitations on measuring three phase flow experimentally but it was specified that such an analysis shall be extremely useful in managing reservoirs with alternate water and gas flooding.

SPE 1942 (1968)

Calculation of Imbibition Relative Permeability for Two and Three-Phase Flow from Rock Properties

Author: Land, C. L

Contribution to the understanding of three phase relative permeability models for WAG injections:
First to establish a relationship for calculating the trapping of gas saturation during the decrease in relative permeability after reaching the saturation history maximum in the increasing saturation direction.

Objective of the paper:
To formulate the calculation of imbibition relative permeability of the non wetting phase while honouring the hysteresis effects.

Methodology used:
Used the Corey-Burdine equation as a general case for the calculation of capillary pressure during two and three phase flow.
Developed a relationship, known as the Land's parameter, for calculation of the trapping of gas during the imbibition cycle.

Conclusion reached:

1. The trapping of gas is a necessary parameter that should be experimentally determined.
2. The wetting phase relative permeability is greater in the imbibition direction than in drainage.
3. A distinct path is traced in the imbibition direction by the relative permeability of the non-wetting phase after reaching the saturation history maximum in the drainage direction.
4. During three phase flow, the water relative permeability is influenced by the change in direction of the gas relative permeability.

Comments:
Land's parameter formed the basis of many hysteresis models that were formulated since then. It was established that two types of gas saturation exists, once the reversal in direction takes place, namely: trapped gas saturation and flowing gas saturation.

SPE 5106 (1974)

Reservoir simulation with History Dependent Saturation Functions

Author: Killough, J. E.

Contribution to the understanding of three phase relative permeability models for WAG injections:
A new model for the calculation of the saturation history dependent relative permeabilities and capillary pressure for the wetting and the non wetting phases.

Objective of the paper:
Simulation of saturation function hysteresis by allowing smooth transitions in either direction between drainage and imbibition of the wetting and the non wetting phase.

Methodology used:
Used the concept of smooth transitions from drainage to imbibition curves and that these transitions are reversible.

Conclusion reached:
Models presented for:

1. Simulation of capillary pressure including the hysteresis effects for the wetting and non wetting phase
2. Simulation of two relative permeabilities including the hysteresis effects for the wetting and non wetting phase.
3. Simulation of three phase relative permeabilities including the hysteresis effects by using second model of Stone.
4. Trapped gas saturation effects the residual oil saturation and must be accounted during simulations.

Comments:
Simulation model for encountering the hysteresis effects in capillary pressure and relative permeabilities for all the phases was presented for the first time. This model assumed that the imbibition curves for the non-wetting phase are reversible in the same direction which is not supported experimentally.

SPE 10157 (1981)

Simulation of Relative Permeability Hysteresis to the Non-wetting Phase.

Author: Carlson, F. M.

Contribution to the understanding of three phase relative permeability models for WAG injections:
A new model for the calculation of imbibition relative permeability hysteresis was formulated.

Objective of the paper:
Simulation of the hysteresis in relative permeability of the non wetting phase with only drainage curve as input.

Methodology used:
Since the imbibition relative permeability is a function of the saturation maximum achieved during the drainage cycle therefore no single imbibition curve for the non wetting phase should be used for reservoir modelling.

Conclusion reached:
Simulation of the relative permeability hysteresis of the non wetting phase can be done with the input of drainage curve only and by specifying the Land’s parameter.

Comments:
This technique can only be used when only dealing with the hysteresis of the non wetting phase. If the imbibition curve is not steeper than the drainage curve then the scanning curves shall cross the bounding curves. It also assumed that the imbibition curve of the non wetting phase is re-tractable which is not supported experimentally.

SPE/DOE 20183 (1990)

Three-Phase Relative Permeability of Water-Wet Berea

Author: Oak, M. J.

Contribution to the understanding of three phase relative permeability models:
The predictions of Stones' models are unsatisfactory when compared with the experimentally measured results of water wet Berea Sandstone.

Objective of the paper:
To experimentally measure the three phase relative permeabilities for eight saturation histories. Then compare the measured results with prediction models of Stone.

Methodology used:
Automated steady state laboratory experiments were carried out for predicting two and three phase relative permeabilities for eight different saturation histories. About 1800 data points were collected for both two and three phase relative permeabilities.

Conclusion reached:

1. Water and gas relative permeabilities are the functions of their own saturations.
2. Oil relative permeability is dependent on the other two phases.
3. The results from Stone's models are unsatisfactory.

Comments:
Automated three phase relative permeability experiments for eight saturation histories was performed for the first time. This led to the experimental verification of the models of Stone. Before this much debate was done on the predictions but this was the first conclusive check of the models.

SPE 38456 (1997)

Methodology for Numerical Simulation with Cycle-Dependent Relative Permeabilities

Author: Larsen, J. A. and Skauge, Arne.

Contribution to the understanding of three phase WAG hysteresis model:
WAG hysteresis is a complex phenomenon that cannot be modelled with the standard two phase reversible hysteresis models.

Objective of the paper:
To develop a WAG hysteresis model that takes into account the complex flow behaviour with saturation history changes.

Methodology used:
Modifications were done to the standard hysteresis models of Killough and Carlson to encounter secondary and tertiary displacements

Conclusion reached:

1. Water relative permeability is reduced following a gas flood. Therefore a three phase curve should be used as an input.
2. Hysteresis models for three phase relative permeability that account for the irreversibility of the scanning curves were developed.
3. A new modification to the residual oil saturation was suggested for the first model of Stone. This was done to honour the increase in oil mobility at lower saturations due to the trapping of gas.

Comments:
A model for the complex WAG hysteresis phenomena was developed for the first time. The residual oil modification for the first model of Stone is not necessary as the increase in oil mobility can be obtained by the second model of Stone.

SPE 63147 (2000)

Comparison of Reservoir Simulation Hysteresis Options

Author: Kossack, C. A.

Contribution to the understanding of three phase relative permeability models for WAG injections:
An attempt was made to simulate WAG hysteresis effects by using Cheshire model for simulation of three phase relative permeability for oil. Recommendations were presented on how to properly simulate the hysteresis effects.

Objective of the paper:
To compare all the available hysteresis options present in a commercial black oil simulator.

Methodology used:
Black oil simulations were done on a simplified two dimensional model for the purpose of generating scanning curves and comparing the results of different models.

Conclusion reached:
Hysteresis in relative permeability and capillary pressures should be accounted in reservoir modelling. If not, then it shall result in increased total hydrocarbon production.

Comments:
Simplified hysteresis models were used with wrong input relative permeability curves for modelling the hysteresis in WAG floods.

SPE 67950 (2000)

An Empirical Model for Three Phase Relative Permeability

Author: Blunt, M. J.

Contribution to the understanding of three phase relative permeability models for WAG injections:
A saturation weighted interpolation method that, accounts for the trapping of non wetting phase and oil layer drainage, predicts Oak experimental data accurately.

Objective of the paper:
To develop an empirical model for three phase relative permeability that can be tested with Oak's measured data.

Methodology used:
An extension is made to the saturation weighted interpolation method of Baker by including trapping of non wetting phase.

Conclusion reached:

1. Saturated weighted interpolation is the best method to predict three phase relative permeability when compared with the models of Stone.
2. Accurate predictions of the measured three phase relative permeability data of Oak.

Comments:
The method was limited to predictions of three phase flow in a strong water wet rock. It cannot be used for predictions of three phase WAG hysteresis due to the uncertainties in saturation histories and especially with non-uniform wettability.

SPE 89921 (2004)

Impact of Relative Permeability Hysteresis on the Numerical Simulation of WAG Injection

Author: Elizabeth J. Spiteri and Ruben Juanes

Contribution to the understanding of three phase relative permeability models for WAG injections:
Standard two phase hysteresis models show reversibility in the scanning curves which is not verified experimentally.

Objective of the paper:
To validate the current hysteresis models by reproducing Oak's measured data of relative permeability.

Methodology used:
Results produced from standard hysteresis models are compared with Oak's measured data for different saturation histories. Then three models that are standard industrial practice are used for predicting oil three phase relative permeability.

Conclusion reached:

1. Standard hysteresis models fail to produce irreversibility of relative permeability scanning curves.
2. Extension to the first model of Stone to account for residual oil seems to be insufficient for capturing the mobility in gas reduction.

Comments:
This work provides a flash back to the initial comparison between the models of Stone and measured data of Oak. However, the limitations of the standard two phase hysteresis models reveal that they should not be used when simulating a complex phenomena such as WAG injection.

APPENDIX B

Table B.1: Cases (ECLIPSE Users Guide) used for Simulating WAG Hysteresis

Cases	Saturation Distribution (from Injector to Producer)
Case 1	Sw = 0.8 – 0.2 Sg = 0.0 So = 0.8
Case 2	Sw = 0.2 Sg = 0.6 – 0.0 So = 0.8
Case 3 (THE REAL WAG)	Sw = 0.2 Sg = 0.0 So = 0.8

Table B.2: Detailed analysis of the results of different hysteresis models in three different cases

RELATIVE PERMEABILITY HYSTERESIS

3 PHASE WATER WET SYSTEM

PLOTS CREATED FOR EACH CASE: BGSAT VS BGKR ; BWSAT VS BWKR ; BOSAT VS BOKR

FILE NAME	MODEL USED	INJECT= WATER AND GAS	SIMULATION RESULTS
WAG4.data	**KILLOUGH'S HYSTERESIS MODEL FOR WETTING AND NON WETTING PHASES; OPTION 4 EHYSTER**	**CASE 1**	ALL SCANNING CURVES ARE GENERATED.
		SGAS = 0	
		SOIL=0.8 - 0.2	
		SWAT = 0.2 - 0.8	
		INJECT= WATER AND GAS	ALL SCANNING CURVES ARE GENERATED.
		CASE 2	
		SGAS = 0.0 - 0.6	
		SOIL = 0.2 - 0.8	
		SWAT = 0.2	
		INJECT= WATER AND GAS	NO SCANNING CURVES ARE GENERATED FOR OIL.
		CASE 3 (REAL WAG)	
		SGAS = 0	
		SOIL = 0.8	
		SWAT = 0.2	
FILE NAME	**MODEL USED**	**INJECT= WATER AND GAS**	**SIMULATION RESULTS**
WAG3.data	**KILLOUGH'S HYSTERESIS MODEL USED FOR NON WETTING PHASE AND IMBIBITION CURVE FOR WETTING PHASE; OPTION 3 EHYSTER**	**CASE 1**	ALL SCANNING CURVES ARE GENERATED.
		SGAS = 0	
		SOIL = 0.8 - 0.2	
		SWAT = 0.2 - 0.8	
		INJECT= WATER AND GAS	
		CASE 2	ALL SCANNING CURVES ARE GENERATED.
		SGAS = 0.0 - 0.6	
		SOIL = 0.2 - 0.8	
		SWAT = 0.2	
		INJECT= WATER AND GAS	
		CASE 3 (REAL WAG)	ALL SCANNING CURVES ARE GENERATED.
		SGAS = 0	
		SOIL = 0.8	
		SWAT = 0.2	

FILE NAME	MODEL USED	INJECT= WATER AND GAS	SIMULATION RESULTS
WAG2.data	KILLOUGH'S HYSTERESIS MODEL USED FOR NON WETTING PHASE AND DRAINAGE CURVE FOR WETTING PHASE; OPTION 2 EHYSTER	CASE 1	ALL SCANNING CURVES ARE GENERATED.
		SGAS = 0	
		SOIL=0.8 - 0.2	
		SWAT = 0.2 - 0.8	
		INJECT= WATER AND GAS	ALL SCANNING CURVES ARE GENERATED.
		CASE 2	
		SGAS = 0.0 - 0.6	
		SOIL = 0.2 - 0.8	
		SWAT = 0.2	
		INJECT= WATER AND GAS	NO SCANNING CURVES ARE GENERATED FOR OIL.
		CASE 3 (REAL WAG)	
		SGAS = 0	
		SOIL = 0.8	
		SWAT = 0.2	
FILE NAME	**MODEL USED**	**INJECT= WATER AND GAS**	**SIMULATION RESULTS**
WAG1.data	CARLSON'S HYSTERESIS MODEL USED FOR NON WETTING PHASE AND IMBIBITION CURVE FOR WETTING PHASE; OPTION 1 EHYSTER	CASE 1	ALL SCANNING CURVES ARE GENERATED.
		SGAS = 0	
		SOIL=0.8 - 0.2	
		SWAT = 0.2 - 0.8	
		INJECT= WATER AND GAS	ALL SCANNING CURVES ARE GENERATED.
		CASE 2	
		SGAS = 0.0 - 0.6	
		SOIL = 0.2 - 0.8	
		SWAT = 0.2	
		INJECT= WATER AND GAS	ALL SCANNING CURVES ARE GENERATED.
		CASE 3 (REAL WAG)	
		SGAS = 0	
		SOIL = 0.8	
		SWAT = 0.2	
FILE NAME	**MODEL USED**	**INJECT= WATER AND GAS**	**SIMULATION RESULTS**
WAG0.data	CARLSON'S HYSTERESIS MODEL USED FOR NON WETTING PHASE AND DRAINAGE CURVE FOR WETTING PHASE; OPTION 0 EHYSTER	CASE 1	ALL SCANNING CURVES ARE GENERATED.
		SGAS = 0	
		SOIL=0.8 - 0.2	
		SWAT = 0.2 - 0.8	
		INJECT= WATER AND GAS	NO SCANNING CURVES ARE GENERATED FOR OIL.
		CASE 2	
		SGAS = 0.0 - 0.6	
		SOIL = 0.2 - 0.8	
		SWAT = 0.2	
		INJECT= WATER AND GAS	NO SCANNING CURVES ARE GENERATED FOR OIL.
		CASE 3 (REAL WAG)	
		SGAS = 0	
		SOIL = 0.8	
		SWAT = 0.2	

It was felt that mostly oil scanning curves were not generated **(Table B3)**. Since oil is treated as an intermediate wetting phase to gas (by default) in the presence of oil, gas and water; then no scanning curves should be generated. But there were two cases **(Table B3)** in which all scanning curves were generated.

Table B2: Cases with unexpected results from the analysis in Table B3

Cases	Simulation Results
WAG4_CASE3	No scanning curves for oil
WAG3	Scanning curves for all required cases
WAG2_CASE3	No scanning curves for oil
WAG1	Scanning curves for all required cases
WAG0_CASE2	No scanning curves for oil
WAG0_CASE3	No scanning curves for oil
*Please refer to Table B2 to view the hysteresis options used in simulation.	

As these models were already classified as simple two phase hysteresis models **(**Larsen *et al.,* and ECLIPSE Technical Description) no further investigation was carried out for the root cause of this behaviour.

Appendix C

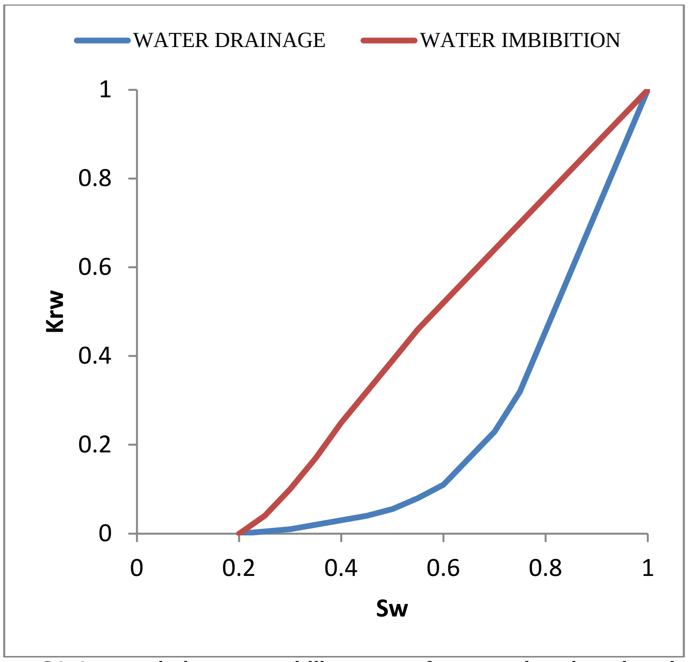

Figure C1: Input relative permeability curves for water (wetting phase)

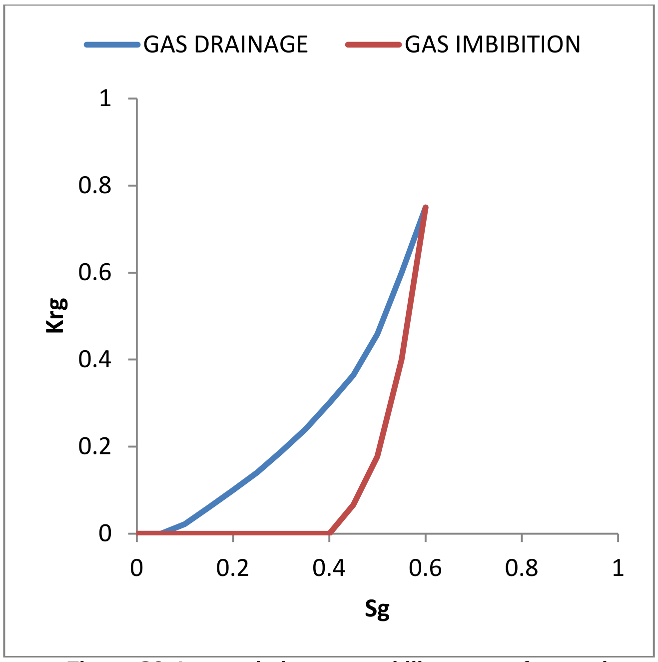

Figure C2: Input relative permeability curves for gas (non-wetting phase)

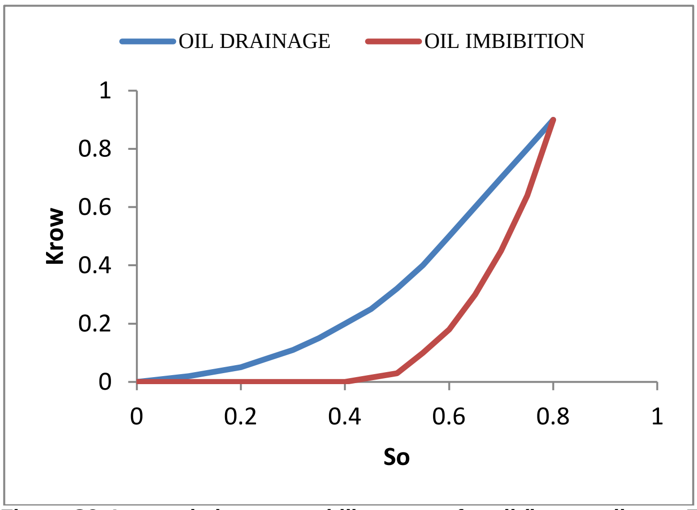

Figure C3: Input relative permeability curves for oil (intermediate wetting phase) in the presence of water (krow)

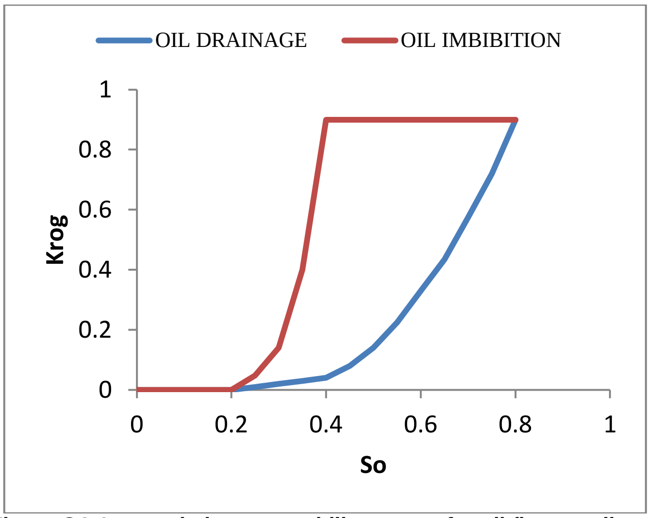

Figure C4: Input relative permeability curves for oil (intermediate wetting phase) in the presence of gas (krog)

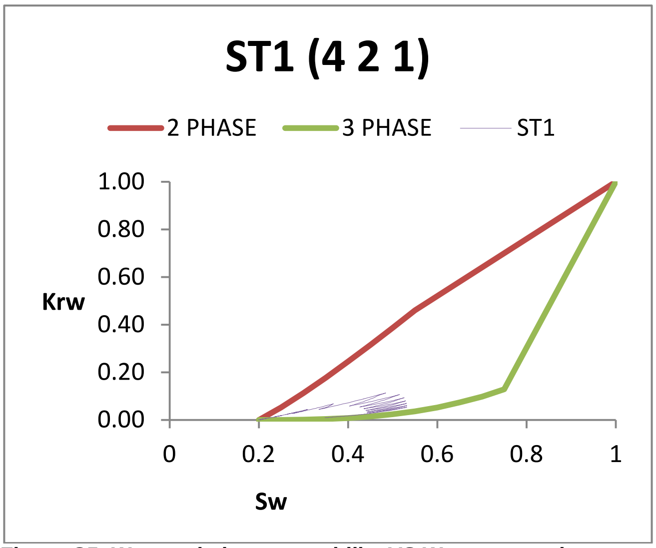

Figure C5: Water relative permeability VS Water saturation for the grid block (4, 2, 1) predicted by ST 1

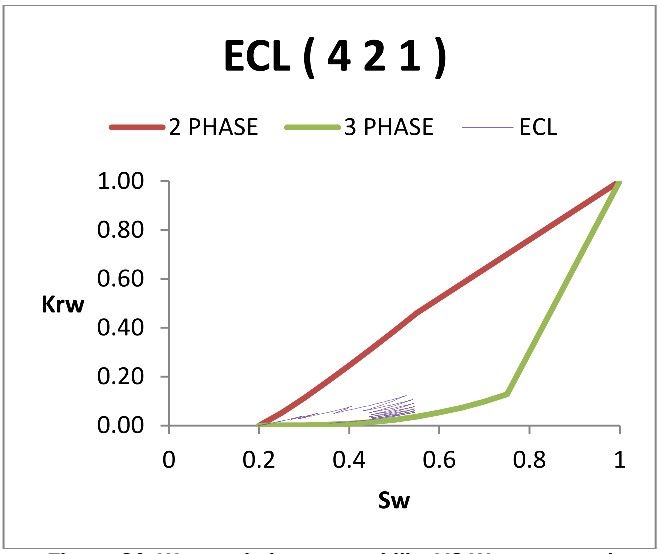

Figure C6: Water relative permeability VS Water saturation for the grid block (4, 2, 1) predicted by ECL Default

water relative permeability for a particular grid block (4 2 1) verses saturation of that grid block

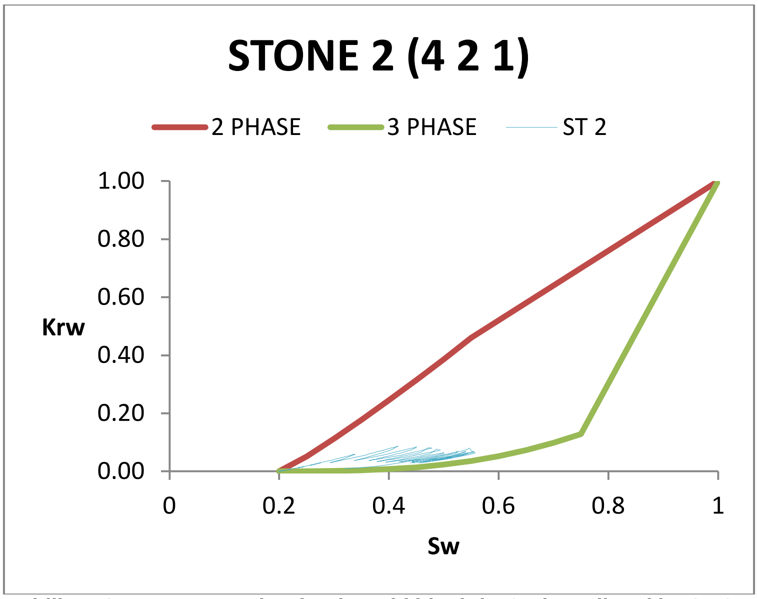

Figure C7: Water relative permeability VS Water saturation for the grid block (4, 2, 1) predicted by ST 2

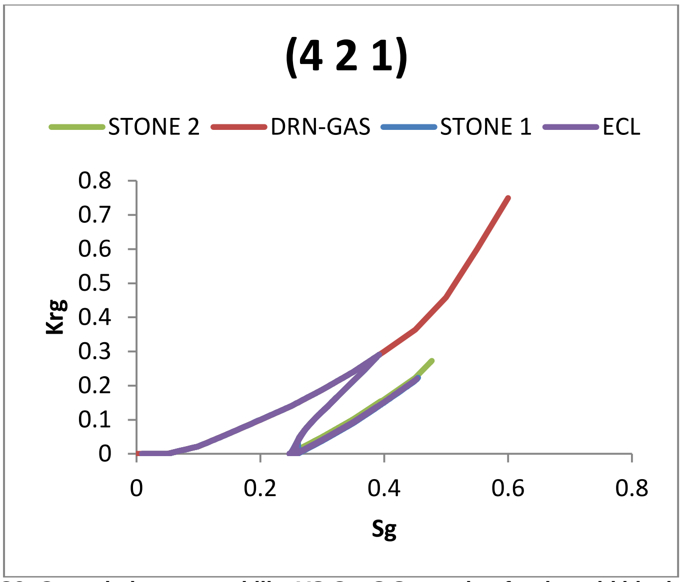

Figure C8: Gas relative permeability VS GasS Saturation for the grid block (4, 2, 1)

APPENDIX D

Example Data Set for IWAG Simulation

```
RUNSPEC   ==============================================================

--TO SUPRESS THE INTERPOLATION OF OIL AND GAS RELATIVE PERMEABILITIES NEART THE CRITITCAL
POINT.
NOMIX

FIELD

OIL
WATER
GAS

-- DEFINES THE COMPOSITIONAL MODE WITH 6 COMPONENTS
COMPS
6 /

UNIFIN
UNIFOUT
TABDIMS
2 1 40 40 /

DIMENS
7 3 3 /

EQLDIMS
-- NTEQUL;NO.OF DEPTH NODES
-- NTEQUL IS THE NUMBER OF EQULIBRATION REGIONS ENTERED IN THE REGIONS SECTION
-- USING THE EQLNUM KEYWORD
   1      20 /

WELLDIMS
-- MAX NO OF WELL;MAX NO OF CONNECT PER WELL
   2                       3 /

--TO FORMAT THE INIT FILE'S OUTPUT REQUESTED IN THE GRID SECTION
--IT WILL INCREASE THE OUTPUT SIZE AND PROCESSING TIME
--FMTOUT



START
1 Jan 1990 /

SATOPTS
HYSTER /

GRID    ================================================================



-- CONTROLS THE AMOUNT OF DATA WRITTEN TO THE GRID GEOMETRY FILE
GRIDFILE
--2 IN THE FIRST OPTION REQUESTS AN EXTENDED GRID FILE CONTAINING LGRs, NNC, INACTIVE CELL
DATA
--1 IN THE SECOND OPTION REQUESTS AN EXTENDED 'EXTENSIBLE GRID FILE' OUTPUT
 2 1 /
```

```
INIT

--THE SIZE OF THE BLOCKS IN X DIRECTIONS CREATED AS VECTORS
DXV
7*500 /

DYV
3*500 /

DZV
20 30 50 /

TOPS
--SPECIFIES THE DEPTHS AT THE TOP OF EACH GRIDBLOCK
--49 IS X INTO Y
-- THREE DEPTHS HAVE BEEN MENTIONED CUZ OF 3 BLOCKS GIVEN IN Z DIRECTION
21*8325 21*8345 21*8375 /

PORO
--49 INTO 3
63*0.3  /

PERMX
21*500 21*50 21*200 /

PERMY
21*500 21*50 21*200 /

PERMZ
21*50 21*50 21*25 /

RPTGRID
 -- Report Levels for Grid Section Data
 --
 'DX'
 'DY'
 'DZ'
 'PERMX'
 'PERMY'
 'PERMZ'
 'PORO'
 'TOPS'
 'PORV'
 'DEPTH'
 'TRANX'
 'TRANY'
 'TRANZ'
 'COORDSYS'
 'COORD'
 /

EDIT

PROPS    ===========================================================

STONE2
--STONE1

EOS
```

```
PR /

-- REQUESTS MODFICATION IN PR WITH THE ACCENTRIC FACTOR
PRCORR

RTEMP
160 /

--STANDARD CONDITIONS
STCOND
60 14.7 /

PARACHOR
74.912
153.48
271.304
404.882676
534.80002
722.26694
/

CNAMES
C1
C3
C6
C10
C15
C20
/

TCRIT
 343.0
 665.7
 913.4
1111.8
1270.0
1380.0
/

PCRIT
667.8
616.3
436.9
304.0
200.0
162.0
/

ZCRIT
0.290
0.277
0.264
0.257
0.245
0.235
/

MW
 16.04
 44.10
```

```
 86.18
149.29
206.00
282.00
/

--ACCENTRIC FACTOR
ACF
0.013
0.1524
0.3007
0.4885
0.6500
0.8500
/

--BINARY INTERACTION COEFFICIENTS
-- IT IS ENTERED IN THE LOWER TRIANGLE FORMAT
--THE NUMBER OF VALUES ENTERED DEPEND UPON THE NUMBER OF COMP MENTIONED IN THE COMPS
KEYWORD
BIC
   0.0
   0.0    0.0
   0.0    0.0    0.0
   0.05   0.005  0.0     0.0
   0.05   0.005  0.0     0.0     0.0 /



SWFN
--2 PHASE CURVE
--table 1
--Sw   Krw   Pc
0.2        0.000     6
0.25       0.052     3
0.3        0.112     2
0.35       0.177     1.15
0.4        0.245     0.6
0.45       0.315     0.3
0.5        0.387     0.12
0.55       0.460     0
1          1         0
/

--Sw    Krw          Pc
--0.200  0.000      3
--0.250  0.002      0.6
--0.300  0.009      0.35
--0.350  0.018      0.23
--0.400  0.032      0.12
--0.450  0.049      0.06
--0.500  0.069      0.024
--0.550  0.110      0
--1.000  1.000      0
--/

--3 PHASE CURVE-40%DRN
--table 2
--Sw    Krw    Pc
```

```
0.2     0.000   2.4
0.25    0.000   2
0.3     0.001   1.6
0.35    0.003   1.2
0.4     0.008   0.96
0.45    0.014   0.76
0.5     0.023   0.56
0.55    0.036   0.4
0.6     0.052   0.28
0.65    0.073   0.16
0.7     0.098   0.1
0.75    0.128   0.04
1       1.000   0

/



SGFN
--Drainage curves
--Table 1 for SATNUM
--Sg   Krg   Pcog  note must have connate gas sat = 0
0      0     0
0.05   0     0.09
0.10   0.022 0.20
0.15   0.06  0.38
0.20   0.10  0.57
0.25   0.14  0.83
0.30   0.188 1.08
0.35   0.24  1.37
0.40   0.30  1.69
0.45   0.364 2
0.50   0.458 2.36
0.55   0.60  2.70
0.60   0.75  3
0.80   1.0   3
/

--Imbibition curves
--Table 2 for IMBNUM
--Sg   Krg   Pcog
-- 0.0    0     0
-- 0.40   0     0
-- 0.45   0.066 0.80
-- 0.50   0.177 1.56
-- 0.55   0.40  2.24
-- 0.60   0.75  3

/
--Sgcr=0.05 critical gas saturation
--the highest for which Krg is zero

--Sgco=0.0 connate gas saturation
--minimum gas sat in the table
--value below the GOC

--Sgmax max gas sat in the table
--Sgmax=1-Swco=1-0.20=0.80
--value above the gas transition zone
```

```
SOF3
--Drainage curves
--Table 1 for SATNUM
--So   Krow   Krog
0.0    0      0
0.1    0.0    0
0.2    0.0    0
0.25   0.08   0.01
0.30   0.11   0.02
0.35   0.15   0.03
0.40   0.2    0.04
0.45   0.25   0.08
0.50   0.32   0.14
0.55   0.4    0.225
0.60   0.5    0.33
0.65   0.6    0.434
0.70   0.7    0.575
0.75   0.8    0.72
0.80   1.0    1.0
/

--Imbibition curves
--Table 2 for IMBNUM
--So   Krow   Krog
-- 0.0    0      0
-- 0.1    0      0
-- 0.20   0      0
-- 0.25   0      0.048
-- 0.30   0      0.14
-- 0.35   0      0.40
-- 0.40   0      0.90
-- 0.50   0.03   1*
-- 0.55   0.1    1*
-- 0.60   0.18   1*
-- 0.65   0.3    1*
-- 0.70   0.45   1*
-- 0.75   0.64   1*
-- 0.80   0.90   1*
/
--Socr=0.2 critical oil sat
--highest for which both krow,krog are 0

--Sorw=0.2 residual oil sat in the oil wat system
--So at which krow becomes 0

--Sorg=0.38 residual oil sat in the oil gas system
--So at which krog becomes 0
--Somax=0.80 max oil sat in the table
--Somax=1-Swco (Sg=0)

WAGHYSTR
2.0  1.0  /
2.0  1.0 4* 0.051 /

ROCKTAB
--ROCK COMPACTION DATA TABLES
--PRESS;PVMULT;,MULTT
 1000.0 1.0   1.0
 2000.0 1.005 1.0
 3000.0 1.010 1.0
```

```
 4000.0 1.015 1.0
 5000.0 1.020 1.0
 6000.0 1.025 1.0
 7000.0 1.030 1.0
 8000.0 1.035 1.0
 9000.0 1.040 1.0
10000.0 1.045 1.0 /

WATERTAB
--WATER PRESSURE TABLES
--PRESS           Bw    vICOSITY
 1000.0    1.0099 0.70
 4000.0    1.0000 0.70
 9000.0    0.9835 0.70 /

--Specify initial liquid composition

ZMFVD
--TOTAL COMPOSITION WITH RESPECT TO DEPTH TABLES
--DEPTH; MOLE FRAC OF EACH COMPONENT

1000.0   0.5 0.03 0.07 0.2 0.15 0.05
10000.0  0.5 0.03 0.07 0.2 0.15 0.05 /

--Surface densities : only the water value is used

DENSITY
1* 62.3 4* /

RPTPROPS
-- PROPS Reporting Options
--
'PVTW' 'PVTG' 'PVDG' 'DENSITY' 'GRAVITY' 'SDENSITY' 'ROCK' 'ROCKTAB'
/

REGIONS    ============================================================

SATNUM
63*1 /

IMBNUM
63*2 /

SOLUTION   ============================================================

--Request initial state solution output

EQUIL
8400 2280 9000 0 7000 0 1 1 0  /

RPTSOL
   -- Initialisation Print Output
   --
'PRES' 'SOIL' 'SWAT' 'SGAS' 'RS' 'SSOL' FIP  /

RPTRST
--BASIC=2 ALL RESTART PRESSURE SOIL SWAT SGAS STEN RS XMF YMF ZMF DENO DENG  /
BASIC=5 ALL PRESSURE SOIL SWAT SGAS STEN RS XMF YMF ZMF DENO DENG BO BW BG /
```

```
SUMMARY    ==============================================================

PERFORMA

--Request field GOR, water cut oil rate and total, gas rate
INCLUDE
'summary.inc'/

SCHEDULE    ===========================================================

--REQUEST THE REPORTS IN PRINT FILE
RPTPRINT
0 1 0 1 1 1 0 1 1 0 /

RPTSCHED
  'PRES' 'SOIL' 'SWAT' 'SGAS' 'RS' 'PWAT' 'PGAS'  /

AIMCON
 6* -1 /

--DRSDT
--  0  /
TSTEP
   1
  /

RPTSCHED
  'PRES' 'SOIL' 'SWAT' 'SGAS' 'RS' 'WELLS=1' 'SUMMARY=2' 'NEWTON=2' 'PWAT'
'PGAS' 'SSOL' 'CPU=2' /

--One stage separator conditions

SEPCOND
Sep Field 1 60 14.7 /
/

--Define injection and production wells

--2000a WELLSPEC is used for back-compatibility, prefered keyword is WELSPECS
WELSPECS
P Field 7 2 8400 OIL /
/

--2000a uses WELSEPC to associate separator with wells
WSEPCOND
P SEP /
/

--2000a WELLCOMP is for back-compatibility, prefered keyword is COMPDAT

COMPDAT
P 7 2 1 3 3* 0.5 /
/


WELSPECS
I Field 1 2 8335 GAS /
/

COMPDAT
```

```
I 1 2 2 3 3* 0.5 /
/


--Well P on oil rate of 12000 stb/day, with min bhp of 1000 psi

--2000a WELLPROD is for back-compatibility, prefered keyword is WCONPROD

WCONPROD
P  OPEN   GRUP   4*  5000 750/
/

--Limits on water cut and GOR
--Note limit is on water cut, rather than water-oil ratio

--GRUPLIM
--Field 2* 0.95 20 1* A Y /
--/

TSCRIT
2* 10 /

TSTEP
--2*365 /
--73*10 /
146*5 /
--292*2.5 /

WELLSTRE
Solvent 0.77 0.20 0.03 0.0 0.0 0.0 /
/

WCONINJE
I GAS  OPEN   RATE  3000  /
/
WINJGAS
I Stream Solvent /
/
WELTARG
I WRAT 5000 /
/
WELLWAG
I T W 182.5 G 182.25 2* 5000 3000   /
/

--TSTEP
--36*182.5 /
--657*10/

--====================================FOR TSTEP OF MORE THAN THOUSAND
YEARS===================================================
--======================= USE MORE THAN ONE TSTEPS THAT ADD TO THE NO. OF DAYS REQUIRED
=====================================

-- CALCULATING TSTEP FOR 1314*5 DAYS ========================================================
TSTEP
1000*5 /

TSTEP
314*5 /
```

```
--
=====================================================================================================

-- CALCULATING TSTEP FOR 2628*2.5 DAYS ============================================================
--TSTEP
--1000*2.5 /
--TSTEP
--1000*2.5 /
--TSTEP
--628*2.5 /
--
======================================================================================================
=

WCONINJE
I GAS  SHUT   RATE  3000  /
/

TSTEP
--4*182.5 /
--73*10/
146*5 /
--292*2.5 /

END
```