Injection of water above gas for improved sweep in Gas IOR: Non-uniform injection and sweep

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Title: Injection of Water above Gas for improved sweep in Gas IOR: Non-uniform Injection and Sweep

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With the continuous increase in the demand for oil and gas, there is a need for application of novel techniques such as Improved Oil Recovery (IOR) and Enhanced Oil Recovery (EOR) methods. Most of the secondary recovery processes start with water flooding. However, injecting gas along with water gives higher recovery than water flood alone. This happens due to the presence of residual gas saturation at the end of the flood which results in lower residual oil saturation than would result from water flood only. Water alternating gas (WAG) injection is the accepted approach for field application in which slugs of water and gas are injected alternatively. Gravity governs the fluid flow in the reservoir if the heterogeneities are not significant. Gharbi et al. (2003) and Stone (2004, 2007) propose an injection scheme in which water is injected simultaneously with, but above, gas into the reservoir. Algharaib et al. (2007) calls this process “modified SWAG (simultaneous water and gas)” injection. Jamshidnezhad et al. (2010) further investigate the effect of instability of gas injection in this process. Non-uniformity of gas injection correlates inversely with the total injection rate and directly increasing vertical distance between the two horizontal injection wells. The paper also speculates that the relationship of gas saturation and gas relative permeability is one of the factors causing instability. The objective of the thesis is to find out the factors that controls the stability of gas injection. To do so, we propose a simulation study which will take into account sensitivity on several parameters that can contribute to stability of gas injection.

We start with a homogeneous reservoir model and later investigate the effects of local grid refinement near the well and heterogeneities. We speculate that the relationship of gas injection rate with gas relative permeability and well gridblock pressure are the vital factors that control the stability of gas flow through the reservoir. The simulation output data is analyzed for varying input data. The variation in the input data is controlled so as to have a clear understanding between results and parameters.

The results from the study indicate that the non-uniform nature of gas injection depends on saturation and relative-permeability behaviour in the neighbouring gridblocks. The instability in the injection process is triggered in the near-well region. Refining the area near the well solves the issue of non-uniform injection process, at least in this study. Segmenting the well into multiple segments gives a wider spread of gas front instead of localized fingering from either end of the well. We study one of the issues in simultaneous water and gas injection process, but several problems like the geology of the reservoir, rock type, geometry of the field, operational aspects and feasibility needs more research and development.
# Table of Contents

ACKNOWLEDGEMENTS........................................................................................................... 2

ABSTRACT................................................................................................................................. 3

List of figures ............................................................................................................................. 5

List of tables ............................................................................................................................. 6

1. INTRODUCTION .................................................................................................................. 7  
   1.1. Background and literature study ..................................................................................... 7  
   1.2. Objective of thesis .......................................................................................................... 9

2. RESERVOIR MODEL ............................................................................................................ 10  
   2.1. Model description and boundary conditions ................................................................. 10  
   2.2. Rock and Fluid properties ............................................................................................ 11  
   2.3. Operating constraints ................................................................................................... 11

3. RESULTS AND DISCUSSION ............................................................................................ 15  
   3.1. Base case model ......................................................................................................... 15  
   3.2. Effect of adjacent gridblocks ...................................................................................... 21  
   3.3. Finer-grid model .......................................................................................................... 22  
   3.4. Variation in Corey exponents ...................................................................................... 24  
   3.5. Position of the water injector ...................................................................................... 25  
   3.6. Segmented gas injection .............................................................................................. 27  
   3.7. Local grid refinement around injection well ................................................................. 29  
   3.8. Effect of heterogeneity ................................................................................................. 32  
   Discussion ............................................................................................................................ 34

4. CONCLUSIONS .................................................................................................................... 35

REFERENCES........................................................................................................................... 36

Appendix – A: Relative permeability functions ..................................................................... 38

Appendix – B: Well Equation .................................................................................................. 38

Appendix – C: Local Grid Refinement ................................................................................... 39

Appendix – D: Additional Figures ........................................................................................... 40
List of figures

Figure 1: Schematic of the input model showing the position of wells. The grey section on the top shows layers with smaller gridblock height. The pink column in the producer well shows the open boundary condition. ................................................................. 12

Figure 2: Distribution of absolute permeability in horizontal and vertical direction, along both the injection wells. ........................................................................................................... 12

Figure 3: Relative-permeability curves for water and gas phase. .................................................. 13

Figure 4: Field results after 20 years of simulation. The plot is limited to 5 years of data to show the variation at the start................................................................. 16

Figure 5: Fraction of the total injected gas in each gridblock along the gas injection well as a function of time. Negative values on Y-axis indicate injection of fluids.................................................. 16

Figure 6: Fraction of gas injected in each segment and gas relative permeability as a function of position along the well, at intervals of 3 months for a period of 3 years: Base Case........................................ 19

Figure 7: a) Steady-state gas relative permeability in the base case in x-y section at 7th gridblock from top with water injector at the centre of formation; b) the same plot as (a) with water injector placed at top of the formation........................................................................ 20

Figure 8: Gas fraction and relative permeability at steady-state conditions after 20 years when water injector is placed at the top of the formation (7th gridblock). .................................................. 20

Figure 9: Comparison of gas fraction at steady-state condition between the arbitrary case and the base case (with two positions of water injection well). .................................................. 21

Figure 10: (a) Fraction of gas injected along the well at steady-state with 15 gridblocks along the y-direction; (b) Fraction of gas injected along the well for the case with 30 gridblocks in y-direction. .... 23

Figure 11: (a) Fraction of gas injected along the gas injector at steady-state with n_y = 1; (b) Base-case gas injection profile. ........................................................................................................... 24

Figure 12: Comparison of different cases showing fraction of gas injected along the gas-injection well with variation in the position of the water injector. .................................................. 26

Figure 13: Evolution of fraction of gas injected along gas-injection well with time - gas-injection well with three segments of five gridblocks each: Case 6.................................................. 28

Figure 14: Fraction of gas injected along well for case with three gas-injection segments (each with five gridblocks) at steady-state after 20 years: Case 6. .................................................. 28

Figure 15: 3D view of gas saturation after 875 days gas injection along with local grid refinement near the gas-injection well........................................................................................................... 30

Figure 16: Gas fraction and relative permeability along the gas injector in the cases with local grid refinement along the gas-injection well. The solid lines indicate the refinement with 3 sub-gridblocks in each direction and the dotted line indicated the refinement with 2 sub-gridblocks in each direction..... 31

Figure 17: (a) Gas relative permeability in a horizontal cross-section at 6th gridblock from the top after 885 days gas injection for refinement of 2 sub-gridblocks in each direction; (b) Gas relative permeability in same cross-section after 875 days gas injection for refinement of 3 sub-gridblocks in each direction near the well. ........................................................................................................... 31

Figure 18: Comparison of gas fraction injected along the gas injector for mildly heterogeneous reservoir with and without local grid refinement.......................................................... 33
Figure 19: Gas relative permeability cross-section below the override zone for the mildly heterogeneous reservoir for (a) the case without LGR and (b) the case with LGR. ............................................................. 33

Figure D 1: This plot shows the fraction of water injected through each gridblock along the water injection well for a period of 20 years. ........................................................................................................... 40

Figure D 2: Fraction of the total injected gas in each gridblock along the gas injection well as a function of time (water injector at top). Negative values on y-axis indicate injection of fluids. ......................... 40

Figure D 3: Gas injection fraction and gas relative permeability as a function of position along the well, at an interval of 8 months for a period of 4 years: Base case with water injector on top of formation........ 41

Figure D 4: Fraction of gas injected and gas relative permeability along the gas-injection well for 5 segments (3 gridblocks each) after 20 years. ........................................................................................................... 42

Figure D 5: a) Gas relative permeability in horizontal cross-section at 6th gridblock from the top for 3 segments in gas injector; b) Gas relative permeability in horizontal cross-section at 6th gridblock from the top for case with 5 segments in gas injector (Case 6). ........................................................................................................... 42

Figure D 6: Horizontal permeability distribution in the reservoir along with local grid refinement near the gas injector........................................................................................................................................... 43

List of tables

Table 1: Properties of water and gas used in the simulator................................................................. 13

Table 2: Summary of all the cases discussed in the results and sensitivity section. The case numbers also correspond to the subsection numbers in Chapter 3........................................................................................................... 14

Table 3: Position of the water injector along with the injector-well pressures for specific cases. ........ 26
1. INTRODUCTION

1.1. Background and literature study
The natural energy of hydrocarbon reservoirs gets depleted as production continues. To restore this energy, injection of gas and/or water is essential to support pressure in the reservoir and provide a good sweeping mechanism. Lake (1989) describes different methods of improving oil recovery from a reservoir. Solvent flooding is one of the improved oil recovery (IOR) techniques that recover oil by extraction, dissolution, vaporization, solubilisation, condensation or any phase behaviour changes. The solvent injected in the reservoir can be continuous or in alternating slugs. The overall displacement efficiency of any oil-recovery displacement can be considered conveniently as the product of microscopic and macroscopic displacement efficiencies.

In a Gas IOR process, the microscopic displacement efficiency can be as large as 100% ($S_o$ to gas sweep $\sim 0$). In an ideal case, the entire volume of the reservoir is contacted by the solvent (in this case gas) but due to certain operational difficulties and geological heterogeneities, the microscopic sweep is not achieved completely. Difference in mobilities between the injected solvents and contacted oil also plays a major role and generally leads to viscous fingering and gravity segregation (Green and Willhite, 1998). The volumetric sweep efficiency in a waterflood alone depends on the macroscopic displacement efficiency which is a product of vertical and areal sweep. Overall remaining oil saturation reflects the magnitude of macroscopic sweep.

Even in homogeneous reservoirs, injected gas has a tendency to segregate at the top of structure due to density difference and gravity. To reduce the effect of adverse mobility ratio, Caudle and Dyes (1958) proposes a technique called water alternating gas injection (WAG). In this method, specified volumes, or slugs, of water and gas are injected alternately. This alternating flow of the two fluids results in reduction of the mobility of each phase. Thus, the combined mobility of the two phases is less than that of the injected gas alone and the mobility ratio improves. The optimal slug of volumes of water and gas depend on the properties of injected fluids and wettability of rock. A common issue in WAG process is blocking, caused by the water phase, between the injected gas phase and the resident oil phase. This reduces the displacement efficiency at pore scale and results in a larger residual oil saturation (Green and Willhite, 1998). Results from a laboratory study show that this effect is a strong function of wettability and detrimental to oil recovery from more water-wet rocks (Parrish et al., 1969). Stone (1984) patents a high viscous to gravity application of WAG in which the total fluid injection rate is large enough relative to the pattern size to cause the significant penetration of gas before gravity segregation happens.

Pester (1999) summarizes the results from various successful projects on WAG. He summarizes the main technical and operational issues that one should take into account while designing a WAG process. Some of the important factors that have a prominent impact on oil production rate and ultimate recovery are well operating constraints, gas production-rate limit, and production and injection-well bottom-hole pressures. With respect to geology, he concludes down-dip WAG injection is more beneficial than up-dip gas injection, and that WAG injection is more attractive with communicating
layers. The paper gives a review of most of the successful projects in WAG injection, the laboratory studies done prior to field application, key parameters and drawbacks.

Instead of injecting alternating slugs of water and gas in the reservoir, it is also possible to inject both the phases simultaneously. This process is termed as simultaneous water and gas injection (SWAG). This method was first tested in the Seelington field in 1962 (Christensen et al., 2001). A simulation study on the application of SWAG in the Kuparuk River field gives interesting insights (Ma et al., 1995). The study concludes there was a loss of injection rate primarily due to lower bottom-hole pressure during two-phase injection. The relative-permeability effect on the injection rates appears insignificant for the range of gas fraction (<0.2) and duration of the pilot study. SWAG was also implemented in the Siri Field in the North Sea (Quale et al., 2000). They analyze the performance of this method and some of the important controlling factors are injectivity in the formation, bottom-hole pressure, fracture-opening pressure and facilities design to reduce environmental effects.

Stone (2004) proposes a new injection scheme where water is injected simultaneously with gas, but from separate wells. In this method, gas is injected from the bottom of the reservoir and water is injected from a site located directly above the gas well. Water injection from the upper part of the reservoir impedes the vertical flow of the gas, allowing it to move horizontally before the segregation of gas takes place. The ratio of water and gas injection rates is a significant factor in controlling the movement of gas flow in vertical direction. In order to use the injection fluids efficiently, the author proposes to curtail water injection rate for short intervals. Use of horizontal wells is also beneficial as it generates a better areal sweep, depending on the heterogeneity present in the reservoir. The paper concludes that simultaneous injection of water and gas can provide 3-fold greater vertical sweep than alternate injection.

Rossen et al. (2006), based on 2D modelling, finds that the process of injecting water above gas results in longer segregation length than can be achieved in uniform co-injection of water and gas at same injection rate. Also, the segregation distance is not affected by the length of the injection interval, injected in a vertical well, in a portion of injection interval or in several separate intervals. Rossen et al. also show that the process is more beneficial when the injection pressure is fixed rather than the injection rate. There is a noticeable concern in this injection process when it is applied in 3D, however. When the fluids are injection in a 2D simulation model, it is obvious that the fluids flow in counter-current direction. In a 3D model, the fluids may by-pass each other as they exit different parts of their respective injection wells. This instability starts slowly in simulations with homogeneous reservoirs but can be initiated more quickly by introducing a small variation in absolute vertical and horizontal permeability along the gas well.

Van der Bol (2007) investigates the effect of gravity segregation in 2D and 3D. The reservoir is homogeneous with slight perturbations in permeability in order to trigger the process of non-uniform injection. For simulations in 3D, the study concludes that non-uniformity develops over time even if perturbations are relatively small. Also, placing the water-injection well closer to gas-injection well might delay the initiation of non-uniform injection, but it is suspected to be a grid effect in the simulation. Van der Bol observes that the gas issues through one end of the well or the other. While
using vertical well, to observe the same effect of gravity segregation, there is no evidence of presence of by-passing. It is suspected in the latter case, coarser grid size and relatively small lateral extent prevents the by-passing to occur. Rossen et al. (2010), using 2D simulations, studies the effect of segregation length while varying the position of injection well positions. This study concludes that the segregation length is unchanged irrespective of the position of gas injector but placing the gas injector at the bottom of the reservoir gives a better sweep. This result is incorporated in this thesis, and gas injector is placed at the bottom of the reservoir. Al-Ghanim et al. (2009) considers heterogeneity with varying permeability distributions in the reservoir. The reservoir model used here is nominally 3D, but there is only one gridblock in one direction, making it effectively a 2D study. This paper focuses on mobility control of SWAG process and its effect on ultimate recovery. Interestingly, the paper concludes that the distance between the gas and water injector wells is not a critical factor that governs the oil recovery. The paper also concludes that modified SWAG method is sensitive to water and gas injection rates, which goes in harmony with the conclusions from literature cited so far.

Jamshidnezhad et al. (2010) studies the effect of total injection rate and gas injection rate to understand non-uniform injection along the gas well. They speculate that effects of gas flow on hydrostatic pressure, and thus on gas-injection pressure, may also play a role. A base-case scenario is modelled to show an ideal case of simultaneous water and gas injection strategy. Instability occurs when gas injection rate or water injection rate is cut down to half of the base case scenario. Instability also occurs when the difference between the steady-state injection pressures in the injection wells is higher. An important observation is that the gas issues from one end of the well or the other irrespective of the size of the reservoir and placement of water injection well. To explore on this result further, gas is injected in separate segments along the gas well with equal injection rate in each segment. The results suggest that almost all the injected gas issues through sites located at the junction of the segments or at one end of the well. Perturbations in the injection rates, vertical distance between the gas and water injection wells and the difference between the steady-state injection pressures show strong correlation with development of instability in gas injection well.

1.2. Objective of thesis

From the literature study, it is clear that the non-uniform flow along the gas injection well in a simultaneous-water-and-gas-injection process is an area which needs more research. On the basis of results from van der Bol (2007) and Jamshidnezhad et al. (2010), we pursued the following objective(s) for the thesis:

First, we try to validate some of the results from Jamshidnezhad et al. (2010) in a reservoir simulator. Later, we consider a range of factors like well model, well representation, rock and fluid properties, size of reservoir, placement of water injector, local grid refinement near the gas injector and reservoir heterogeneities. The primary objective is to find out the controlling factor(s) that cause instability in injection in the gas injection well. We speculate on how the relationship between gas saturation and relative permeability and total injection rate affect this process. We conclude with possible solutions to prevent non-uniform flow from gas-injections, well to improve vertical sweep for the modified SWAG process.
2. RESERVOIR MODEL

The assumptions from study of Jamshidnezhad et al. (2010) are approximated in most of the models used here. These assumptions are described in the following sections. Shell’s Modular Reservoir Simulator, MoReS (version 2012.1) is used to represent the reservoir. MoReS uses finite difference method for numerical discretisation and applies both implicit and explicit techniques for solving the equations for pressure and saturation changes.

2.1 Model description and boundary conditions

The static model used for the simulations is a horizontal rectangular grid. The results from the 2D theory for injection of water above gas (Rossen et al. 2006) are not dependent on the size of the reservoir. We select a grid size from the study of Jamshidnezhad et al. (2010) for our base case in order to validate few cases from the paper. Later we also investigate the effect of grid size on numerical dispersion and the accuracy of the results.

The height of the reservoir is fixed at 40 meters. Except when mentioned, the length is 64 meters and width of 60 meters. Van der Bol (2006) concludes that even if there is no bypassing of gas from vertical injection wells, the sweep is still better while implementing horizontal wells. This condition has been honoured in all the cases irrespective of the model dimensions. Figure 1 shows a schematic representing the wells in the model. The height of a gridblock is 1.5 m, except for the top five layers where the height is 0.5 m. This is to observe in detail the movement of gas flow after segregation occurs. For base case model, the number of gridblocks is 32x15x30. Each gridblock has a length of 2 m in x-direction and width of 4 m in y-direction. The injector wells are placed in the first sheet of gridblocks. The gas injector is placed in the bottom-most row along the co-ordinates (1, y, 30), as this gives a relatively better vertical sweep (Rossen et al. 2010). For the base case, we place the water injector in the centre row at co-ordinates (1, y, 17). Both the horizontal injectors are extended along the complete width of the reservoir. To observe the impact of steady-state difference in injection-well pressures, we vary the position of water injector. This variation is mentioned in the sensitivity analysis. For all cases, the vertical production well is placed in the last sheet of gridblocks with co-ordinates (32, 7, z) and it is perforated along the complete reservoir height.

The top and bottom of the reservoir are closed boundaries and an open boundary is represented as follows. The production well is placed in the last column of gridblocks and it is perforated along the entire height of the reservoir. The entire last sheet of gridblocks represents an open boundary. The absolute permeability in x-direction in this sheet is set very high (1 Darcy) to avoid any barrier for fluid flow and prevent pressure build-up. The absolute permeability in z-direction in the same sheet is set to zero to eliminate resistance to flow towards the production well in that column.
2.2 Rock and Fluid properties
For all cases, porosity in the entire reservoir is 25%. Except for the sealed boundaries, the horizontal permeability is 1000 mD and vertical permeability is 210 mD, as in Jamshidnezhad et al. (2010). We contend that if the gas injection is unstable in a homogeneous reservoir, then it is definitely more so in a realistic, heterogeneous reservoir. A case with heterogeneous reservoir is also analyzed and as explained in the results section. Along the two injection wells, both horizontal and vertical permeability varies randomly, with values selected from a uniform distribution extending approximately ±10% from the reservoir values. Figure 2 shows the crossplot of vertical and horizontal permeabilities in the gridblocks along the gas injection well. In a case, where the number of grid blocks increases in y-direction, the distribution of absolute permeability along the injection wells is interpolated with respect to the base-case. The small variation in permeability is introduced to initiate the instability in the fluid flow. To validate the results from Jamshidnezhad et al. (2010), we try to approximate the same range of variation. If the perturbation in permeability is not included, the instability develops but takes longer (Van der Bol 2007). It is speculated that (without the perturbations) this is initiated by round-off errors in the computations. A realistic heterogeneous reservoir has more variation than the range of values used in this thesis.

Following Stone (1982), Rossen et al. (2010), van der Bol (2007) and Jamshidnezhad et al. (2010), we study the steady-state flow behaviour of injected gas and water with no mobile oil present. An immobile oil saturation of 0.1 is present in all the simulations. Immobile oil reduces the gas and water mobilities and, therefore, at fixed injection rate, the injection pressure would be higher if any residual oil is present. But the presence of immobile oil does not change the fundamental nature of gas-water segregation. According to Lake (1989), mobile oil near the well can change the nature of the displacement but we do not take this into account in our model. The properties of gas are represented at reservoir conditions. Both water and gas phase are incompressible. Relative permeability plays an important role in gravity segregation and mobility control in modified SWAG process. The same set of relative-permeability functions is used in every case, except for the case describing sensitivity analysis of end-point values in the relative-permeability function. Figure 3 plots the relative-permeability function used in the base case. As mobile oil is not present, it is effectively a two-phase relative-permeability model. The functions, along with the end-point values for saturation and Corey exponents for all the phases, are described in Appendix A. Table 1 summarizes the properties of fluids.

2.3 Operating constraints
The initial pressure in the reservoir is 138 bars. The vertical production well is constrained at 138 bars at the top of the formation. The gas and water injectors are operating under injection-rate constraint. 26% of the total injected fluid is water while the remaining fraction is gas. With a total fluid injection rate of 223 m$^3$/day, the water injection rate is 58 m$^3$/day while the remaining 165 m$^3$/day gas injection. The simulations run with these rate constraints, allowing the bottom-hole pressure in the wells to vary accordingly. For most cases, we simulate a period of 20 years to ensure the attainment of steady-state flow. When exceptions are made, the constraints and simulation time are specified accordingly. As we speculate that the injection behaviour of gas is dependent on the bottom-hole pressure at the injector, we allow it to vary in some cases.
Figure 1: Schematic of the input model showing the position of wells. The grey section on the top shows layers with smaller gridblock height. The pink column in the producer well shows the open boundary condition.

Figure 2: Distribution of absolute permeability in horizontal and vertical direction, along both the injection wells.
Figure 3: Relative-permeability curves for water and gas phase.

Table 1: Properties of water and gas used in the simulator.

<table>
<thead>
<tr>
<th>Property</th>
<th>Water</th>
<th>Gas</th>
</tr>
</thead>
<tbody>
<tr>
<td>Density (kg/m$^3$)</td>
<td>1000</td>
<td>163*</td>
</tr>
<tr>
<td>Viscosity (cP)</td>
<td>1</td>
<td>0.0144*</td>
</tr>
<tr>
<td>Compressibility (1/bar)</td>
<td>$10^{-7}$</td>
<td>$5 \times 10^{-12}$</td>
</tr>
</tbody>
</table>

* Values at reservoir conditions
<table>
<thead>
<tr>
<th>Case</th>
<th>No. of grids (reservoir size)</th>
<th>Model description</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>32x15x30 (64x60x40 m)</td>
<td>Base case with gas-injection well located at the bottom of the formation and water-injection at one of two different locations. The purpose of this is to study the non-uniform injection of gas along its well and observe the influence of neighbouring gridblocks on the well gridblocks as we reach steady-state.</td>
</tr>
<tr>
<td>2</td>
<td>32x15x30 (64x60x40 m)</td>
<td>We modify the base case by reducing the absolute permeability in y-direction to 1 mD.</td>
</tr>
<tr>
<td>3</td>
<td>32x15x30 (200x200x40 m)</td>
<td>In this case, we use a larger reservoir model to study the impact of grid size on the distribution of gas along the gas-injection well.</td>
</tr>
<tr>
<td>4</td>
<td>32x15x30 (64x60x40 m)</td>
<td>Base case with changes made in the Corey exponents for gas- and water-phase relative permeabilities. To see the impact of mobility properties of the fluids.</td>
</tr>
<tr>
<td>5</td>
<td>32x15x30 (64x60x40 m)</td>
<td>A case to study the impact of placement of the water injection well and validate the hypothesis that the instability in gas injection is correlated with the hydrostatic pressure difference between the gas- and water-injection wells.</td>
</tr>
<tr>
<td>6</td>
<td>32x15x30 (64x60x40 m)</td>
<td>A case to evaluate the arguments from Jamshidnejad et al. (2010) on segmented injection.</td>
</tr>
<tr>
<td>7</td>
<td>32x15x30 (64x60x40 m) Near-well grid refinement (3,3,3) and (2,2,2)</td>
<td>Use of static local grid refinement in the near-well region, to study the effect on the gas-injection profile along the trajectory. We use two different grid refinements for comparison.</td>
</tr>
<tr>
<td>8</td>
<td>32x15x30 (64x60x40 m)</td>
<td>Addition of 10% variation in absolute permeability in the complete reservoir model. Investigate the results with and without the use of local grid refinement. Also compare the results with cases (1) and (7).</td>
</tr>
</tbody>
</table>

Table 2: Summary of all the cases discussed in the results and sensitivity section. The case numbers also correspond to the subsection numbers in Chapter 3.
3. RESULTS AND DISCUSSION

The focus of our study is primarily on stability in gas injection along the horizontal injection well rather than the segregation of water and gas or the distance to the point of segregation of the phases. Van der Bol (2007) describes the tendency to develop an unsteady flow pattern along the gas injection-well. Jamshidnezhad et al. (2010) explain this behaviour by simulating number of cases with variations in different factors. Before we start the discussion on results in this thesis, we validate the results from Jamshidnezhad et al. (2010). Due to the lack of the actual dynamic model used in that study (which was created in the simulator CMG-STARS), we replicate the model in MoReS using the details from the paper. For the model size of 200x200x40 m, we were not able to reproduce the result in the paper of unstable gas injection. We think this could be due to the use of a different simulator or well-model equation or some difference in the input properties not mentioned in the paper. We re-produce a few cases for a reservoir size of 64x60x40 m, which we discuss in the following sections. We also observe that total fluid rate used in Jamshidnezhad et al. (2010) is approximately proportional to the area of reservoir model. Since our aim is to study the instability in gas injection, we need to define a base case model having a unstable injection. We then conduct further sensitivity studies using this base case model. A summary of all the cases discussed in this thesis are described in Table 2.

3.1 Base case model

We simulate the base case with a total fluid injection rate of 223 m$^3$/day into a region of 64x60x40 m; injected water makes up 26% of the total fluid rate while the remaining fraction is gas. To observe the effect of position of the water injector on base case, we also simulate a case where the water injector is located at the top of the formation (7th row from the top). Nevertheless, first we look at the results of model when the water injector is located in the centre of formation height. We simulate this model for 20 years to make sure that we reach steady-state conditions. We observe that steady-state is achieved in approximately 3 years. At steady-state, gas-injection rate is not uniform along the gas injection well. To observe this, we plot the gas fraction injected along the horizontal gas-injection well. As noted previously by Jamshidnezhad et al. (2010), we also observe that water injection is nearly uniform along its well, with only 10% variation from smallest to largest values (Figure D 1). This is due to 10% variation in absolute permeability along the injection wells. At steady state, gas injection, however, does not correlate with perturbations in permeability. As we speculate that the changes in gas saturation and hence the relative permeability plays a significant role in the non-uniform injection of gas, we also plot the gas relative permeability along with the gas-fraction until we establish the steady-state condition.

Figure 4 shows that total injection rates are constant shortly after injection begins. The plot is limited to 5 years so as to show the variation during the starting phase. We see steady-state flow after 3 years of simulation time. As the wells operate on rate constraint, we observe constant rates for water and gas all the time. At steady-state, the injection pressure in the gas injector is 424 kPa above the initial pressure and the injection pressure in the water injector is 371 kPa above the initial pressure. We observe a difference of 53 kPa between the injection pressures of the two wells, which is similar to difference Jamshidnezhad et al. (2010) note.
We monitor the gas fraction injected through each gridblock along the gas-injection well in Figure 5. This plot is helpful to understand the interaction of injected gas with neighbouring gridblocks. We also monitor the gas fraction through the entire gas-injection well to understand the distribution of gas fraction in the well. This plot is combined with a relative-permeability plot along the same gas-injection well, which helps us to better understand the relation between the injection rate and relative permeability and correlate accordingly. Since we observe the steady state after 3 years, Figure 6 shows the fraction of total gas injected and relative permeability along the gas injection well for a period of 3 years with each plot at an interval of 3 months.

**Figure 4**: Field results after 20 years of simulation. The plot is limited to 5 years of data to show the variation at the start.

**Figure 5**: Fraction of the total injected gas in each gridblock along the gas injection well as a function of time. Negative values on Y-axis indicate injection of fluids.
The production well is operated at a bottom-hole pressure of 138 bars. Water and gas are injected simultaneously at fixed rates. As we start the simulation, the bottom-hole injection pressure rises rapidly in the beginning and reaches a maximum of 12 bars above the initial pressure. From Figure 5 and Figure 6, we see that gridblock 1, 8, 12, 13 continuously decrease in rate as well as relative permeability. Gridblock 12 and 13 approaches zero gas fraction. We observe an increasing flow through gridblock 14 and 15 in the beginning but after one year less gas issues from them. We speculate this is due to the influence of gridblock 12 and 13, which have continuously decreasing trend of relative permeability. Except gridblock 1, we see that all the gridblocks from 2 to 6 have a relatively increasing trend of injected gas for an average period of 2 years. Thus, the relative-permeability increase in these gridblocks affects the properties for gridblock 1. So the gas fraction increases in gridblocks 1, 2 and 3 as we move towards steady-state flow. On the other end of the well, we observe that the relative permeabilities in the last five gridblocks approach zero. Flow rate through gridblock 10 remains constant before it drops steeply to very low fraction. This influences the adjacent gridblocks to flow at lower fractions. Therefore, at the end of 2 years we see that gridblock 5 has the highest fraction of gas issuing through it, and gridblock 1, has one of the lowest fraction of gas issuing through it. As we achieve the steady state, this situation reverses and gridblock 1 has the highest fraction of gas issuing through the entire section of the well. This shows how the relative permeability, and hence the gas-saturation behaviour in the adjacent cells, can influence the mobility properties of the parent gridblock. Evidently, the fate of a given part of the well is connected both to its own relative permeability but also to the injection rate in its neighbors. The volume of the reservoir that the gas contacts is one of the factors that affects sweep efficiency. The issuing of gas from exclusively from either end of the well should reduce sweep. As the injected gas flows from one end of the well, it selects a preferential path towards the production well. Figure 7 (a) shows an x-y cross-section of gas relative permeability at the 7th gridblock from the top, which is just below the override zone. We observe that the gas flows through one end of the well and moves up to segregate in the override zone.

We make a small change to this case by changing the position of the water injector. We place the water injector at the top of the formation (6th gridblock) just below the override zone. The permeability distribution along the wells remains same as the previous case. The water injection is stable and uniform along the well with less than 10% variation (Figure D 1). The gas fraction along the gas-injection well after 20 years is shown in Figure 8. In this case, the gas bypasses from the other end of the well compared to the previous case. Also, it takes longer to reach steady-state. This may be due to the larger distance between the injection wells. Figure D 3 shows the gas fraction along the trajectory of the well with time for a period of 4 years. We observe similar development of non-uniform gas injection as gridblocks 1, 2, 4, 8, 12 and 13 inject negligible amount of gas. Gridblocks 14 and 15 show a continuously increasing fraction of injected gas with time. After 2 years, gridblocks 12 and 13 show increasing trend of gas injection volume. At steady state, the last four gridblocks inject the greatest amount of gas. This is completely opposite to the results in the previous case and clearly shows the influence of neighbouring cells on flow properties. Also, the magnitude of relative permeability values at steady state is greater than in the previous case. Figure 7 (b) shows the x-y cross-section of gas relative permeability at steady-state just below the override zone.
Figure 6: Fraction of gas injected in each segment and gas relative permeability as a function of position along the well, at intervals of 3 months for a period of 3 years: Base Case.
Figure 7: a) Steady-state gas relative permeability in the base case in x-y section at 7th gridblock from top with water injector at the centre of formation; b) the same plot as (a) with water injector placed at top of the formation.

Figure 8: Gas fraction and relative permeability at steady-state conditions after 20 years when water injector is placed at the top of the formation (7$^{th}$ gridblock).
3.2 Effect of adjacent gridblocks

The results from the base-case model suggest that the loss of uniformity in a gas injection well is due at least in part to the influence of adjacent gridblocks. The flow characteristic in the neighbouring cell causes the parent cell to change its fluid flow properties such as saturation and thus, the relative permeability and flow rate. To check the reliability of this speculation, we build a model where the sheet of gridblocks perpendicular to the well (i.e., extending in the x- and z-directions) are nearly isolated from each other. We increase the flow resistance in the y-direction by reducing the absolute permeability to a minimum possible value throughout the reservoir. In MoReS, a value of 0 mD is not valid in a well gridblock, since the geometric flow factor which is used in the well model equation is a product of permeability in ‘x’ and ‘y’ direction (Appendix B). So we use a value of 1 mD as the permeability in ‘y’ direction in the whole model keeping the rest of model the same as in the base case. We simulate this model for a longer time (50 years) to see the effect of smaller value of permeability in ‘y’ direction. To compare the results with base case, we plot the gas fraction along the gas injection well at steady-state conditions (Figure 9). The solid lines indicate the comparison of arbitrary case and the base case when the water injector is placed at the centre of the formation, while the dotted line indicates the same comparison when the water injector is place at the top of the formation. In the arbitrary case, we see that the gas injection distribution along the gas injector is more stable and uniform than the respective base cases. When the water injector is placed at the centre of the formation, the distribution is more uniform. In the base case, when the water injector is placed at top, we observe that the magnitude of relative-permeability values is higher than with the base case with water injector in centre.

Nonetheless, injection is still unstable with the water injection at the top of the reservoir. Although the influence of adjacent gridblocks appears to be important (Figure 6 and D3), that influence is not transmitted by flow in the y-direction. We do not understand how this influence is transmitted.

Figure 9: Comparison of gas fraction at steady-state condition between the arbitrary case and the base case (with two positions of water injection well).
3.3 Finer-grid model

During the first step of validating the results from Jamshidnezhad et al. (2010), we observe certain exceptions and differences between our results and theirs. Jamshidnezhad et al. report that if the water and gas injection rate fractions are cut by half or one-fourth from that in the base case, they observe an unstable gas-injection profile. However, we fail to observe this result; such a change from the base case does not trigger an unstable injection profile. Differences between simulators could be one of the reasons for this difference.

We compare the results from Jamshidnezhad et al. (2010) for the case with reservoir model size of 200x200x40 m to our defined base case (64x60x40 m). We observe in the base case the instability occurs at a total injection rate of 223 m$^3$/day. If we hold total injection rate proportional to the length of the well as well length increases from 60 m to 200 m, we should increase the rate by 3-3.5 times. Jamshidnezhad et al. (2010), on the other hand, increase total injection rate proportional to horizontal area of the reservoir, as they hold the height of the reservoir constant. As a result, while attempting to repeat Jamshidnezhad's injection rate, we observe that the both steady-state injection-well pressures increase drastically and not in the way reported by Jamshidnezhad et al. (2010). So to scale our base case to a reservoir model of 200x200x40 m, we reduce the total injection rate from 2283 m$^3$/day and keep the fractional distribution of water and gas constant. At an injection rate of 1350 m$^3$/day, we observe a noticeable difference in fraction of gas injected in each gridblock along the well (Figure 10(a)). Although this extent of non-uniform injection is not as severe as in other cases, we observe relatively more injection rate at one end of the well. At gas injection rate of 2283 m$^3$/day, the fraction of gas injected along the gas-injection well is uniform and more evenly distributed, but the injection pressure is higher than in the base case. As we reduce the total fluid injection rate the injection pressure decreases and we get a non-uniform injection profile, as in Figure 10(a).

In Figure 10(a) we hold the total number of gridblocks constant as we change the size of the reservoir model. Consequently, as a check of this, we run a second case where we increase the number of gridblocks in the y-direction by a factor of two. Thus we use a total of 64x30x30 gridblocks for the model of 200x200x40 m. Figure 10 shows the difference between the gas injection profiles for two similar cases with varying number of gridblocks in y-direction. The non-uniformity of injection along the gas well is more severe than in with fewer gridblocks. The results in this section indicate that the use of correct grid size and injection rate can clearly make a prominent difference in the stability of injection process.
Figure 10: (a) Fraction of gas injected along the well at steady-state with 15 gridblocks along the y-direction; (b) Fraction of gas injected along the well for the case with 30 gridblocks in y-direction.
3.4 Variation in Corey exponents

From the results of the base case, we believe that the non-uniform nature of gas injection is related to the gas-saturation changes, and hence the relative permeability, in the wellbore gridblocks (Figure 6).

We use the standard relative-permeability model (Corey’s 2-phase model) to simulate the base case. The end-point values for saturation and relative permeability for both the phases, gas and water, are described in the Appendix A. The Corey-exponents used in the base case ($n_w = 2.5$, $n_g = 2$) are relatively neutral, not giving any preferential mobility to a specific phase. Our next step is to vary the fundamental equation for mobility and change the exponents of the Corey equation. We perform two tests. We decrease the value for $n_g$ to unity, which results in a linear relation between saturation and relative permeability for gas phase. We compare the results to the base case, maintaining the position of the water injector halfway between the bottom and top of the formation. With smaller value of $n_g$, we expect more gas mobility due to the linear correlation with saturation. Figure 11 compares both the cases. Case (a) also develops a non-uniform injection profile but the gas issues from other end of the well as compared to base case. Gridblocks 14 and 15 account for 80% of flow from the well. Gridblocks from 1 to 8 have close to zero gas injection. This result does not show any change in gas injection profile along the well. This proves again that the uniform injection of gas does not depend on the relative permeability functions but rather the values in the neighbouring blocks.

![Figure 11](image)

**Figure 11**: (a) Fraction of gas injected along the gas injector at steady-state with $n_g = 1$; (b) Base-case gas injection profile.
3.5 Position of the water injector

Jamshidnezhad et al. (2010) conclude that the non-uniform injection correlates weakly with the gas-injection pressure but more strongly with the difference between gas- and water-injection pressures. They speculate that effects of hydrostatic pressure on gas injection plays an important role. A solution to observe the effect of difference between the injection-well pressures is to vary the position of injection wells. Rossen et al. (2007) and Algharaib et al. (2007) show that the most efficient position for a gas injection well, in an ideal 2D scenario, is the bottom-most position. Gas injector at the bottom assures more contact with the volume of the reservoir, and thus generating a relatively better sweep efficiency. We honour this requirement in all our sensitivity studies below. The alternative then is to vary the position of the water-injection well. This variation should alter the injection-well pressures and generate a different gas-injection profile.

Our base case contains 30 gridblocks along the ‘z’ direction. We have already discussed the results for the position of water injector in the centre of the formation and at the top of the formation. Table 3 shows the results for seven different positions of the water-injection well in ‘z’ direction. The difference between the injection-well pressures decreases as the distance between the two wells reduces. We observe that when the water injector is at gridblock 24 (counting from the top), the pressure difference is negative (water-injection pressure greater than gas-injection pressure). In Figure 12, we compare the gas fraction along the gas injector for all the cases in the Table 3. For the water injector in gridblocks 6, 9 and 12, a huge fraction of the gas issues from the last three gridblocks. This is similar to the base case where the water injector position is at the top of the formation. When the water injector is at the gridblock 15 and 18, the results are similar to the base case with the water injector in the centre of the formation. As we move lower to the gridblock 21, the gas is injected uniformly from the first 7 gridblocks. The remaining half portion of the well has negligible gas injection. As the distance between the two injectors decreases the ΔP approaches zero. When both the wells are at closer distance, the ΔP is close to zero and gas is injected uniformly.

While defining the objectives for this study, we speculate the effect of hydrostatic pressure on gas flow may play a role. This case closely validates the hypothesis we make and also agrees to one of the conclusions made by Jamshidnezhad et al. (2010). Uniform gas injection is one of the criteria for a successful implementation of modified SWAG method, because of its impact on volumetric sweep efficiency. For all the cases, the fraction of water injected along the well varies by only about 10%. When the water injector is placed at gridblock 24, we see a uniform gas-injection profile. A general observation in the literature is when the water injector is placed farthest from the gas-injection well the volume contacted by gas is often the highest. Therefore one may sacrifice the volumetric sweep in the reservoir by placing both the injectors close to each other. On the other hand, we lose the uniformity in gas injection profile as the difference between the injection-well pressures increase, and this also adverse affects the gas-injection profile.
Position of injector from top (m) | Position at the grid (Z) | Gas-well pressure | Water-well pressure | ΔP (bars)
--- | --- | --- | --- | ---
3.25 | 6 | 142.06 | 140.58 | 1.48
7.75 | 9 | 142.08 | 140.77 | 1.31
12.25 | 12 | 142.11 | 141.07 | 1.04
16.75 | 15 | 142.18 | 141.43 | 0.75
21.25 | 18 | 142.28 | 141.85 | 0.43
25.75 | 21 | 142.46 | 142.36 | 0.1
30.25 | 24 | 142.79 | 142.95 | -0.16

Table 3: Position of the water injector along with the injector-well pressures for specific cases.

Figure 12: Comparison of different cases showing fraction of gas injected along the gas-injection well with variation in the position of the water injector.
3.6 Segmented gas injection

In most of the cases discussed so far, gas issues from one end of the well, generating a non-uniform injection profile. A possible solution this behaviour is to introduce multiple segments in the gas injector (Jamshidnezhad et al., 2010). This way, the gas issues from either end of these several segments. We examine this technique using the base case: all the other properties of the reservoir are the same as the base case. We divide the gas injection well into three equal segments with same fixed injection rate in each. In the base case, gas-injection well injects 165 m$^3$/day of gas. In segmented injection, each segment with 5 gridblocks injects 55 m$^3$/day of gas keeping the other operating conditions constant.

**Figure 13** shows the gas injection in each wellbore gridblock with time. Gridblocks 1, 8, 12 and 13 show a continuously decreasing gas fraction. Gridblocks 5, 6 and 15 show continuously increasing gas fractions with time. Most of the intermediate gridblocks which lie in between the segments show a fairly constant gas flow through them. The gas fraction through gridblock 11 increases initially, but the gas fraction in the neighbouring gridblocks 10 and 12 continuously decrease with time. The relative permeability in gridblock 11 keeps dropping over time as we approach steady state. The gas flow through the gridblocks 7 and 11 decreases initially, but evidently due to the influence of the relatively high flow through gridblocks 6 and 15, we see moderate amount of gas flowing through 7 and 11. As compared to the base case, this case takes a longer time, 5 to 6 years, to reach steady-state. At the end of the simulation, we see two main areas from which almost all the gas issues. **Figure 14** shows the gas-injection profile along the well after 20 years. Jamshidnezhad et al. (2010) argue, if there are $N$ segments in the injection well, then the gas comes out in $[(N+1)/2]$ well segments for $N$ odd, and $N/2$ for $N$ even. We are able to validate this argument successfully. We authenticate the argument further by increasing the number of segments along which the gas is injected. **Figure D 4** shows the result for segmented injection with 5 segments in the base case scenario. According to the analogy, with gas injection into five segments, the gas should issue from 3 places. The first place should be at the connection of first and second segment, the second place should be at the connection of third and forth segment and the third place should be at the end of fifth segment. We see the gas issues at gridblocks 3, 5, 9, 10 and 15. The small gas injection in gridblock 5 is an anomaly. We suspect this is due to lesser number of gridblocks in y-direction per segment. A better approach would be to increase the number of gridblocks in y-direction when increasing the number of segments. **Figure D 5** compares gas relative permeability in horizontal cross-sections at the 6th gridblock, just below the override zone, for both the cases discussed so far. Increasing the number of segments leads to gas issuing from more than one place, which should result in more even volumetric sweep in the y-direction. Jamshidnezhad et al. (2010) suggest a better strategy for segmented injection would be to insert a gap between segments. An ideal case to achieve uniform gas injection is to increase the number of the segments until gas injection is spread all along the well. Practically, this may not be feasible in field since the cost of smart well completion with controlled injection is significant. A possible alternative solution would be to scan the log data from the horizontal gas-injection well and divide it into several segments with the least variation in horizontal permeability.
Figure 13: Evolution of fraction of gas injected along gas-injection well with time - gas-injection well with three segments of five gridblocks each: Case 6.

Figure 14: Fraction of gas injected along well for case with three gas-injection segments (each with five gridblocks) at steady-state after 20 years: Case 6.
3.7 Local grid refinement around injection well

So far, the sensitivity analysis shows the behaviour of gas injection with respect to changes that we make in fluid properties, grid size, placement of water-injection well, gas injection through several segments and dependence of mobility properties on neighbouring gridblocks. In all these cases, we keep the near-well properties constant from case to case and use the same well-model equation (Peaceman’s equation). Different commercial reservoir simulators have several types of well-model equation. The well-model equation calculates the fluid flow properties for use in calculating the flow in injection and production wells from the reservoir gridblock. MoReS uses only the Peaceman equation since it is the most standard model and is well researched. The distribution of gas throughout the reservoir in the simulation depends on the outflow near the gas-injection well. Over a period of time, as the gas-saturation front moves towards the production well, these properties are amplified and we may achieve an irreversible non-uniform gas injection profile. In our last sensitivity analysis, we refine the near well region using ‘static local grid refinement (LGR)’.

A reservoir simulator describes the flow of fluids through a porous medium by solving a discretised set of fluid-flow and thermodynamic equations. The standard approach to this discretisation, or gridding, as for instance applied in MoReS, is to use a structured grid which covers the reservoir as a simple box in which the different axes have been discretised (MoReS manual). A disadvantage of a structured grid is its inflexibility. Many phenomena such as flow patterns around wells and movements of saturation fronts are localized in time and space. These are not well described by the more-or-less uniform gridding procedure described above, unless a very large number of gridblocks and small time-step sizes are used. This, however, has obvious disadvantages concerning computational time and memory usage. To solve these issues, we adopt a static local grid refinement method combined with local time stepping. We do not focus on the discretisation effects and different methods of refinement. Rather we concentrate on the refinement of properties in when applying LGR. Appendix C describes the different properties and the simulator approach towards refining these properties.

We use a simple grid refinement along the gas-injection well and the three gridblocks surrounding it. Figure 15 shows the gas saturation profile along with LGR. Because the computational time for a simulation increases with more refinement, we study just two cases with different refinement. In first case, we refine the coarse gridblocks containing the gas-injection well into 27 smaller sub-gridblocks by refining each by a factor of three in all three directions. In the second scenario, we refine these gridblocks into two smaller sub-gridblocks each in all three directions. We use the adaptive implicit method for simulating these cases. The bottom-hole pressure in the gas injector reaches a maximum of 9.7 bars above the initial pressure with 423 kPa being the steady-state pressure after 2 years, which is approximately equal to our observation in the base case. Figure 16 shows a relatively uniform gas fraction distribution along the gas-injection well for both the cases of grid refinement. There is a small variation in the gas distribution for both cases, as there was in previous cases where the injection-profile was not unstable (Jamshidnezhad et al., 2010). We also plot the gas relative permeability cross-section (x-y) below the override zone in Figure 17. The gas-saturation front from Figure 15 shows a more-uniform and steady profile compared to the base case. Most likely, near-well region of the gas-injection
well plays a significant role in development of non-uniform injection. If so, a more-accurate representation of the near-well region might eliminate the problem. This deserves further study.

Figure 15: 3D view of gas saturation after 875 days gas injection along with local grid refinement near the gas-injection well.
Figure 16: Gas fraction and relative permeability along the gas injector in the cases with local grid refinement along the gas-injection well. The solid lines indicate the refinement with 3 sub-gridblocks in each direction and the dotted line indicated the refinement with 2 sub-gridblocks in each direction.

Figure 17: (a) Gas relative permeability in a horizontal cross-section at 6th gridblock from the top after 885 days gas injection for refinement of 2 sub-gridblocks in each direction; (b) Gas relative permeability in same cross-section after 875 days gas injection for refinement of 3 sub-gridblocks in each direction near the well.
3.8 Effect of heterogeneity

In most of the cases discussed above, we observe a non-uniform flow of gas through the gas-injection well. However, the reservoir is homogeneous in these cases, except at each injection well. In our last case, we use a reservoir model with varying absolute permeability in the horizontal and vertical directions. We use Petrel, a Schlumberger tool, to map this variation in the static model. We select ±10% permeability variation in the entire reservoir model, except for sealed-boundary conditions and the original permeability distributions along the wells. A 10% variation may not project a realistic geological model, but it does test the sensitivity to small variations in permeability. We keep the fluid-flow rate constant and also operate at the same well constraints. From the results of Jamshidnezhad et al. (2010), it is obvious that the gas injection profile is correlated with the absolute permeability along the injection well. Nevertheless, it is not clear whether the permeability variation throughout the reservoir model would make a difference on the final gas-injection and gas-saturation profiles. In the previous section, we generate a very stable injection profile with the help of static local grid refinement. So in this section we generate results for both the base case and with local (3x3x3) grid refinement in the near well along with the 10% variation in the permeability distribution throughout the reservoir. Figure D 6 illustrates distribution of horizontal permeability in 3D which was imported from Petrel model.

Figure 18 shows the gas fraction along the gas-injection well at constant average reservoir pressure for both the cases, with and without local-grid refinement, for this heterogeneous reservoir. We observe a negligible difference between the final results for the base case with and without heterogeneity. This implies that a small degree of heterogeneity in absolute permeability does not make any major change in the sweep efficiency. It is possible that the variation in the permeability is not significant enough to cause a change in the gas-injection profile. Greater variation in absolute permeability, and longer correlations in permeability, may lead to different result. Also with local grid refinement, as compared to the previous section, mild heterogeneity does not make any major changes, and we see a relatively uniform gas front moving towards the production well. In the previous sections, we speculate that the near-well region plays a significant role in the development of non-uniform gas injection. This section shows that mild heterogeneity away from the well is not so important. According to the well model in Appendix C, the gridblocks in which the well intersects also leads to different results. The equivalent well block radius equation uses the grid size and permeability values in the intersected gridblock.
Figure 18: Comparison of gas fraction injected along the gas injector for mildly heterogeneous reservoir with and without local grid refinement.

Figure 19: Gas relative permeability cross-section below the override zone for the mildly heterogeneous reservoir for (a) the case without LGR and (b) the case with LGR.
Discussion

In this study, we focus mainly on one aspect of SWAG process – non-uniform injection behaviour in the gas-injection well. We observe significant insights that we describe in the conclusions. There are some limitations as well as some future development prospects from the results in this study.

- Higher total injection rate does not necessarily lead to non-uniform flow. However, if the designed rates in the field are in the range that generates a non-uniform gas-injection profile, it should certainly lead to lesser volumetric sweep. A possible future direction for research would be to define an envelope of fluid injection rates using analytical expression that would prevent the instability in gas injection.
- The flow from well node to the gridblock depends on the equation that the simulator uses. MoRes uses Peaceman’s equation for all the cartesian grid simulations. We are not sure about the effect of using a different well equation.
- While defining the objective of the study, we expect a simple analytical expression having two gridblocks should clarify the injection behaviour. But the base case results indicate that the neighbouring gridblocks around the parent gridblock have a significant impact. Thus, a two cell model is not sufficient to answer the results seen so far.
- We are not able to validate some cases from Jamshidnezhad et al. (2010) at the given injection rates. The rates should be scaled to the length of the well; increasing the injection volumes in proportion to the area of the reservoir leads to higher injection pressures.
- We use the most simple static local grid refinement with a sub-division of coarse gridblock into three and two smaller sub-blocks in each direction, along three rows in y-direction near the gas-injection well. We have not tried to optimize the level of refinement.
- The permeability values are in moderate to high range. This leads to lower injection pressures and better injectivity. Lower permeabilities should most certainly lead to higher injection pressures and/or low injectivity.
- There is no mobile present in the reservoir model. It can influence the flow of gas and water considerably.
- We do not use the vertical well for the entire study. According to Van der Bol (2007), vertical wells do not lead to by-passing of gas, but using horizontal wells gives more injectivity and hence more sweep efficiency.
4. CONCLUSIONS

From the simulation study in the thesis, we draw the following conclusions.

- The injected gas in a horizontal well tends to bypass through either end of the well creating a non-uniform injection profile. The behaviour in the adjacent gridblocks influence the mobility in the parent gridblock even if the well in the given gridblock is injecting at a higher injection rate.
- From the results testing the effects of adjacent grid blocks, we validate our first conclusion. If there is no connectivity between the neighbouring it does not lead to entirely non-uniform injection profile.
- Refined grid size for entire reservoir gives a sharper profile for injection along the gas injector. Using a larger grid size could result in better sweep but would generate erroneous results.
- The difference between the steady-state bottom-hole pressures in the injection wells correlates with gas-injection behaviour. The difference between the pressures is dependent mainly on the distance between the well locations. Placing the injection well close to each other gives a more uniform injection but (based on 2D studies in the literature) may not result in good volumetric sweep.
- Increasing the number of segments in segmented gas injection ensures the issuing of gas from multiple locations, as stated by Jamshidnezhad et al. (2010).
- Using local grid refinement leads to a more-uniform gas-injection profile along the well trajectory. It is possible that the unstable injection behaviour seen by Jamshidnezhad may have been the result of poor grid refinement near the injection well.
- The mild variation in heterogeneity in our last case does not change the injection profile significantly. Greater variation in absolute permeability might alter the results.
REFERENCES


Appendix – A: Relative permeability functions

We use the same standard equations to define the relative permeability function as applied in the work of Jamshidnezhad et al. (2010).

\[ k_{rw} = k_{rw}^* \left( \frac{S_w - S_{wc}}{1 - S_{wc} - S_{gc}} \right)^{n_w} \] (A1)

\[ k_{rg} = k_{rg}^* \left( \frac{S_g - S_{gc}}{1 - S_{wc} - S_{gc}} \right)^{n_g} \] (A2)

\[ k_{ro} = 0 \]

The end point values for the above relations are constant in all the simulations unless stated otherwise.

\[ k_{rw}^* = 0.3; k_{rg}^* = 1; S_{wc} = 0.2; S_{gc} = 0.15; n_g = 2; n_w = 2.5; \mu_g = 0.0144 \text{ cP}; \mu_w = 1 \text{ cP}; S_o = 0.1. \]

Appendix – B: Well Equation

Peacemann (1978) develops an analytical solution, the interval inflow equation, which calculates the flow between an interval node in a well-bore and the reservoir gridblock surrounding it. In MoRes, it is termed as ‘geometric flow factor’. This geometric flow factor is defined as,

\[ T_i = \frac{\Theta_i K_{Hi}}{\ln \left( \frac{r_{E,i}}{r_{w,i}} \right) + S_i} \]

\( \Theta_i \): angle open to the flow
\( KH_i \): interval permeability thickness product
\( r_{E,i} \): equivalent well-block radius
\( r_{w,i} \): well-bore radius
\( S_i \): interval skin

The equivalent well-block radius \( r_E \) is the radial distance from the well at which the grid block pressure matches the analytical solution. Peacemann’s equation to calculate the equivalent well block radius \( r_E \) is

\[ r_E = G \sqrt{\frac{\Delta x^2}{K_y} + \frac{\Delta y^2}{K_x}} \left( \frac{4 K_x}{K_y} + \frac{4 K_y}{K_x} \right) \]

\( G \) is a mathematical constant which is approximately equal to 0.2807298. When the horizontal permeability is isotropic the equivalent well block radius simplifies to,

\[ r_E = 0.1403649 \sqrt{\Delta x^2 + \Delta y^2} \]

Most of the results in our study implement the second equation for equivalent well block radius.
Appendix – C: Local Grid Refinement

In a coarse-grid model, there are several existing arrays of properties defined for the reservoir model. When a grid is refined into sub-gridblocks, these properties need to match with the new grid structure. The property arrays are divided into four different categories.

a. Basic geometric properties: gridblock volume and node heights are calculated from the coarse gridblock coordinates.

b. Interface properties: conventional transmissibilities are calculated such that they give same fluxes into the sub-blocks as these went into the original coarse gridblock.

c. Intensive properties: absolute permeabilities and pressures are given values such that a suitable average of all the sub-blocks equal to the original coarse gridblock.

d. Extensive properties: component accumulations are treated such that the sum of the sub-blocks equals the original gridblock value

The simulator takes forward the intensive properties into the sub-blocks as these reflect the original geological features and averaging these properties might result into an unrealistic model. The extensive properties are scaled down proportionately to sub-block volume. In our case, since all the sub-block volumes are equal, we expect an equal distribution of these values. We show a few examples below to illustrate the calculation of these properties in refined gridblocks. If $L_1$, $L_2$, $L_3$ are the coarse block lengths and $l_1$, $l_2$, $l_3$ are those for sub-blocks respectively, then a scaling factor for interface area in one plane is

$$\frac{a_{i,1}}{A_1} = \frac{l_{i,2}l_{i,3}}{L_2L_3}$$

Similarly, for example, convection transmissibilities $t_i$ for sub-blocks is

$$\frac{t_{i,1}}{T_i} = \frac{a_{i,1}(l_{i,1}k + l'k_1)}{A_1(L_1K_1 + L_1K'_1)}$$

Primes denote the neighbour block on the other side of interface area. For extensive properties the sub-block values are

$$x_i = \frac{x_i v_i}{V}$$

Where $v_i$ and $V$ are the volume for sub-block and coarse block respectively. During simulations, sub-block values are used to calculate the accumulations and flow parameters. So in this procedure the coarse gridblock values are determined automatically from sub-block values. For example, extensive properties are simply the sum of sub-block values. For intensive properties it is an average,

$$X = \frac{\sum x_i}{n_i}$$

$n_i$ is the number of sub-blocks.
Appendix – D: Additional Figures

**Figure D 1:** This plot shows the fraction of water injected through each gridblock along the water injection well for a period of 20 years.

**Figure D 2:** Fraction of the total injected gas in each gridblock along the gas injection well as a function of time (water injector at top). Negative values on y-axis indicate injection of fluids.
Figure D 3: Gas injection fraction and gas relative permeability as a function of position along the well, at an interval of 8 months for a period of 4 years: Base case with water injector on top of formation.
Figure D 4: Fraction of gas injected and gas relative permeability along the gas-injection well for 5 segments (3 gridblocks each) after 20 years.

Figure D 5: a) Gas relative permeability in horizontal cross-section at 6th gridblock from the top for 3 segments in gas injector; b) Gas relative permeability in horizontal cross-section at 6th gridblock from the top for case with 5 segments in gas injector (Case 6).
Figure D 6: Horizontal permeability distribution in the reservoir along with local grid refinement near the gas injector.