Title : Ensemble Optimization of CO\textsubscript{2} WAG EOR

Author(s) : Danny Natanael Tjahyono Bahagio

Date : July 19, 2013

Professor(s) : Jan Dirk Jansen

Supervisor(s) : Olwijin Leeuwenburgh (TNO)
Rahul Fonseca (TU Delft)
Pieter Kapteijn (Maersk Oil)
Son Huu Do (Maersk Oil)
Liping Zhang (Maersk Oil)

TA Report number : AES/PE/13-12

Postal Address : Section for Petroleum Engineering
Department of Geoscience & Engineering
Delft University of Technology
P.O. Box 5028
The Netherlands

Telephone : (31) 15 2781328 (secretary)
Telefax : (31) 15 2781189

Copyright ©2013 Section for Petroleum Engineering

All rights reserved.
No parts of this publication may be reproduced,
Stored in a retrieval system, or transmitted,
In any form or by any means, electronic,
Mechanical, photocopying, recording, or otherwise,
Without the prior written permission of the
Section for Petroleum Engineering
Acknowledgements

I would like to express my gratitude and thanks to my wife, son, parents and brothers for the continuous love, support and encouragement so that I can finish my master study of Petroleum Engineering in Delft University. I don’t think I could finished my study without the incredible help they provided, which enabled me to overcome a couple of difficult periods during my study. Many thanks to them.

Doing my graduation project in Maersk Oil was one of the best decisions I've made during my master study. I got the best possible balance between academic, technical, business and professional experience by working on an optimization problem using a real-life Maersk Oil dataset. I was lucky enough to be based in the Copenhagen office during this work and was helped and guided by some of the best reservoir engineer around. I would like to thank Jan Dirk Jansen and Pieter Kapteijn for this wonderful opportunity.

Working on this optimization problem really helped me to improve my programming skills and gave me a new point of view on how to maximize the value of an asset. I have to say thank you to Olwijn Leeuwenburgh and Rahul Fonseca for their guidance, advice and support that allowed me to understand and utilize the Ensemble Optimization method to improve the CO$_2$ WAG EOR operations studied in this thesis.

I also want to say special thanks to Son Do and Liping Zhang for their guidance, advice and lectures in the midst of their busy schedules. I significantly improved my reservoir engineering and simulation skills by working under their tutorage.

Last, I also have to thank all of my professors in TU Delft and all of my friends and colleagues who have made my 2 years in TU Delft so colorful and memorable.
Abstract

CO₂ Water Alternating Gas (WAG) EOR (Enhanced Oil Recovery) is a method to improve oil recovery by combining improvement in displacement efficiency from CO₂ injection and improvement in sweep efficiency from injecting water in alternating sequence with CO₂. This thesis focused on using the Ensemble Optimization method to improve the economics of this project in anonymous field X with discounted NPV (Net Present Value) as the objective function. The optimized variable is the injection BHP (Bottom Hole Pressure) for water and gas injection with fixed injection cycle of 6 months on each of water and gas cycle. The optimized result was compared with the result from the base case CO₂ WAG with maximum injection BHP on each of the water and gas cycle and it showed promising result by optimizing the amount of injected water and gas on each injection cycle by controlling them from the injection BHP. Optimized strategy gave $30 million incremental in discounted NPV or equal to 4% increase in discounted NPV compared to the discounted NPV from the base case strategy contributed from higher oil production and better CO₂ utilization than the base case.
# Table of Contents

Acknowledgements ................................................................................................................. 3  
Abstract .................................................................................................................................. 4  
1. INTRODUCTION ..................................................................................................................... 7  
   1.1. Objective.......................................................................................................................... 7  
   1.2. Optimization..................................................................................................................... 7  
   1.3. Problem Definition ......................................................................................................... 8  
   1.4. Hypothesis ..................................................................................................................... 8  
   1.5. Thesis Outline ............................................................................................................... 8  
2. En-Opt & Objective Function ................................................................................................ 9  
   2.1. Objective Function (discounted NPV) Definition ........................................................... 9  
   2.2. Ensemble Gradient Estimation (En-Opt) ......................................................................... 10  
3. Trigen Technology ............................................................................................................... 13  
   3.1. Trigen Technology ........................................................................................................ 13  
4. CO₂ Gas Injection and WAG (Water Alternating Gas) Injection ....................................... 14  
   4.1. Why do we use CO₂ for gas injection ............................................................................. 14  
   4.2. Miscible and immiscible flood ...................................................................................... 16  
   4.3. WAG (Water Alternating Gas) injection ....................................................................... 17  
   4.4. Important parameters in WAG injection ...................................................................... 19  
5. Field X – Introduction and Preliminary Run ...................................................................... 20  
   5.1 Preliminary Run; Waterflood VS Pure CO₂ Injection VS CO₂ WAG ............................ 24  
6. CO₂ WAG EOR Run in Field X ........................................................................................... 29  
   6.1. Pricing for Objective Function Calculation .................................................................. 29  
   6.2. Optimization Result ...................................................................................................... 30  
   6.3. Comparison of Optimized WAG, Base Case WAG, Pure Gas Injection and Waterflood on Field X for 10 years of Run .............................................................................. 35  
7. Conclusion ............................................................................................................................. 37  
8. Recommendations and Way Forward ................................................................................. 38  
REFERENCES ............................................................................................................................ 39  
List of Figures ............................................................................................................................ 41
List of Tables ........................................................................................................................................... 43
Appendix A: Additional Runs using En-Opt .......................................................................................... 44
Appendix B: Dynamic Time Bounds Constraints for Half Cycle Injection Length of water or CO₂ .......... 45
Appendix C: Comparison of En-Opt Run with Time and Injection BHP as Control Parameters Compared to Injection BHP only as Control Parameters ................................................................. 48
  C.1. Field Y ........................................................................................................................................... 48
  C.2 WAG Run with Only Injection BHP as Control Parameters ......................................................... 49
    C.2.1 En-Opt and Pricing Data ........................................................................................................... 49
    C.2.2 Results .................................................................................................................................... 50
  C.3 WAG Run with Injection Cycle Length and Injection BHP as Control Parameters ................. 53
    C.3.1 En-Opt and Pricing Data ........................................................................................................ 53
    C.3.2 Results .................................................................................................................................... 54
  C.4 Comparison Between Injection Length and BHP as Control Parameters VS BHP Only as Control Parameters ............................................................................................................................ 57
1. INTRODUCTION

1.1. Objective

The objectives of this study are:

a) To demonstrate the feasibility of CO₂ WAG EOR (Water Alternating Gas Enhanced Oil Recovery) optimization using TriGen generated CO₂ and Maersk asset data.

b) To demonstrate the suitability of the En-Opt method for CO₂ WAG EOR optimization in comparison with the established methodology (always inject with maximum BHP).

c) To extend the optimization functionality of the existing TNO Matlab waterflooding optimization tool and make it suitable for CO₂ flooding optimization.

1.2. Optimization

Optimization is the process of finding optimal values of control parameters to achieve a certain objective. This process is particularly useful for complicated processes with multiple controllable variables that may also be dependent on each other.

The purpose of optimization is to find the maximum or minimum value of an objective function from a certain model with several control parameters while respecting constraints. In the oil and gas industry, optimization is traditionally performed with trial and error methods and applied to activities such as infill drilling, waterflood and gas injection. This traditional process is usually reactive in nature, which means that an action is initiated after a certain phenomenon occurs, e.g., close a subsurface valve or well after the production has reached a certain watercut threshold. Optimization via mathematical techniques has recently become possible with the advancement of methods such as gradient-based optimization, genetic algorithms, and simulated annealing. These optimization methods allow a paradigm shift in the way that production and reservoir management is performed from reactive to proactive processes.

One of the most powerful methods is a gradient-based technique using the adjoint method to compute the gradient (Brouwer, 2004). This is an efficient optimization method because it can calculate the gradient accurately with one additional run of the reservoir simulation, but the downside of this method is that it needs access to the backend of the simulator code to add additional calculation to apply the adjoint calculation which makes this method less flexible because it is difficult to get access to the backend of the simulator code especially in commercial reservoir simulators.

As an alternative, an ensemble (collection of samples) based method for production optimization was proposed and developed by Nwaozo (2006), Lorentzen et al. (2006) and Chen et al. (2008) which is called Ensemble Optimization (En-Opt). En-Opt approximate the gradient of the objective function with respect to the ensemble of control parameters. The gradient information is used to optimize the control parameters...
and maximize the objective function (Fonseca, 2011). The advantages of En-Opt are that it does not require access to the backend of simulator code and the number of forward simulations are only depend on the number of ensemble and iteration, so it is independent from the number of control parameters although more control parameters will need more computational time on the En-Opt algorithm but the time needed for this calculation is minor compared to the time required to run the reservoir simulation. While En-Opt offer many advantages, it also has a drawback; it is computationally less efficient and a good result will requires several ensembles and iterations which mean more forward simulation. With all of those plus and minus side, En-Opt still proved to give a good results with reasonable computational cost.

1.3. Problem Definition
The well control parameter in reservoir simulation usually are defined manually which may or may not be the optimum solution. This thesis clarified this uncertainty using the En-Opt method to find the optimum well control parameters which will maximize the objective function in CO$_2$ WAG EOR process.

1.4. Hypothesis
“The application of the En-Opt method in a CO$_2$ WAG EOR process will help to maximize the economic objective function of the project which is defined as the discounted NPV (Net Present Value).”

1.5. Thesis Outline
The mathematical derivation of En-Opt and the objective function is given in chapter 2. A literature review of Trigen technology is given in chapter 3 while literature review about CO$_2$ Gas Injection and WAG (Water Alternating Gas) Injection is given in chapter 4. Chapter 5 contain the introduction of anonymous field X and preliminary run on field X. Chapter 6 contain the result and discussion of En-Opt run for CO$_2$ WAG EOR in field X and also comparison between waterflood, pure CO$_2$ injection, base case CO$_2$ WAG and optimized CO$_2$ WAG in field X. Conclusions are given in chapter 7. Recommendations and way forward about opportunities for further improvement are given in chapter 8.
2 En-Opt & Objective Function

2.1. Objective Function (discounted NPV) Definition

The En-Opt method was used to maximize the objective function (discounted NPV) for a CO$_2$ WAG EOR process. The discounted NPV can be maximized by increasing oil production, minimizing water injection, minimizing water production, minimizing gas injection and minimizing gas production. The objective function is defined as

$$ J = \sum_{k=1}^{K} \left[ \left( Q_{o_k} \cdot r_o - \left( Q_{w_{pk}} \cdot r_{wp} + Q_{w_{ik}} \cdot r_{wi} + Q_{g_{pk}} \cdot r_{gp} + Q_{g_{ik}} \cdot r_{gi} \right) \right) \frac{t_k}{(1 + b)^{\tau_k}} \right] \Delta t_k. \quad (1) $$

Note:
- $J$ = Discounted NPV (Net Present Value)
- $K$ = total number of time steps
- $Q_{o_k}$ = oil production rate (bbl/day)
- $Q_{w_{pk}}$ = water production rate (bbl/day)
- $Q_{w_{ik}}$ = water injection rate (bbl/day)
- $Q_{g_{pk}}$ = gas production rate (Mscf/day)
- $Q_{g_{ik}}$ = gas injection rate (Mscf/day)
- $r_o$ = price of produced oil ($/bbl$)
- $r_{wp}$ = price of produced water ($/bbl$)
- $r_{wi}$ = price of injected water ($/bbl$)
- $r_{gp}$ = price of produced gas ($$/Mscf$$)
- $r_{gi}$ = price of injected gas ($$/Mscf$$)
- $\Delta t_k$ = time length between each time steps (days)
- $b$ = discount factor (fraction)
- $t_k$ = cumulative time (days)
- $\tau_k$ = reference time for discounting (365 days)
2.2. Ensemble Gradient Estimation (En-Opt)

The general mathematical derivation of En-Opt are derived below following Leeuwenburgh et al. (2010). The control parameters are defined as

\[ \mathbf{u} = [u_1, \ldots, u_N]^T, \]  

where \( N \) is the number of control parameters. Since we will only focus on single model optimization then our objective function \( J \) will only depend on the control parameters \( \mathbf{u} \) and not the varying properties of the reservoir, so \( J = J(\mathbf{u}) \). The idea behind En-Opt is to take \( M \) random samples from the control space by Gaussian perturbation around the current control and evaluate the corresponding objective function values \( J \) by running the simulator once with each perturbed control vector. The ensemble-mean control parameters are obtained as

\[ \bar{\mathbf{u}}_l = \frac{1}{M} \sum_{j=1}^{M} \mathbf{u}_l^j, \]  

for all control vector elements \( l = 1, \ldots, N \). In the same manner, the ensemble-mean objective function is obtained as

\[ \bar{f}(\mathbf{u}) = \frac{1}{M} \sum_{j=1}^{M} f^j(\mathbf{u}), \]  

with \( j = 1, \ldots, M \) and \( M \) is again the number of control samples. The ensemble matrices of control vectors and objective functions are

\[ \mathbf{U} = \begin{pmatrix} u_1^1 - \bar{u}_1 & \ldots & u_N^1 - \bar{u}_N \\ \vdots & \ddots & \vdots \\ u_1^M - \bar{u}_1 & \ldots & u_N^M - \bar{u}_N \end{pmatrix}, \]  

\[ \mathbf{j} = \begin{pmatrix} j_1 - \bar{j} \\ \vdots \\ j_M - \bar{j} \end{pmatrix}. \]  

If we apply linear regression through \( M \) points \( (\mathbf{u}^1 - \bar{u}, j^1 - \bar{j}) \) then we can estimate a regression coefficient factor

\[ \mathbf{\beta} = (\mathbf{U}^T \mathbf{U})^{-1} \mathbf{U}^T \mathbf{j}. \]
It can be shown that $\beta$ approximates the true gradient $\nabla f$ (Egberts et al., 2011). In the following explanation the notation $g$ will be used to indicate the stochastic gradient instead of $\beta$. The two terms in Eq. 8 and 9 is the estimation for the cross-covariance between $u$ and $f$ and for the auto-covariance of $u$,

$$ C_{u,f(u)} \approx \frac{1}{M-1} (U^T j), $$

and

$$ C_u \approx \frac{1}{M-1} U^T U. $$

With these definitions,

$$ g = (M - 1)(U^T U)^{-1} \frac{1}{M - 1} (U^T j) = (U^T U)^{-1} (U^T j), $$

or

$$ g \approx C_u^{-1} C_{u,f(u)}. $$

The gradient information from En-Opt is used to calculate a new update for the controls using the steepest ascent formula

$$ u_{k+1} = u_k + \alpha_k g_k, $$

where $\alpha$ is the step size and $k$ is the iteration index.

The flow chart of En-Opt method is explained in Figure 1 while the detail of the outer and inner iteration and trust region method is explained in the Nocedal and Wright (2006).
Figure 1 En-Opt Flow Chart
3. Trigen Technology

3.1. Trigen Technology

Trigen is an oxy-fuel combustor which utilizes pure oxygen at a high pressure and high temperature environment around 100 bars and 2000 °C to efficiently burn low quality gas with high CO₂ content. The plant generates electricity via a steam/gas turbine. Application of high pressure, high temperature oxy-fuel technology enabled Trigen to produce near-complete combustion reaction resulting in electricity, pure and low cost CO₂ with price around ≈ $1.7/MSCF although the actual price is varies from project to project. This CO₂ based Trigen price will be used as base price for CO₂ injection in the optimization process with specific price according to the targeted project. Another stream of by-product from the combustion process in Trigen plant is pure water and pure nitrogen as the by-product from the ASU (Air Separation Unit) as depicted in Figure 2 (Kapteijn et al., 2012).

Full benefit from Trigen can be obtained by building a “Trigen Based Value Chain” utilizing all of the material from the process (Figure 3). The pre-requisite of this value chain is low quality gas field with high CO₂ content as the source of fuel gas for Trigen, power infrastructure and demand for electricity nearby and oil field with potential to be developed using EOR method of CO₂ gas injection while the nitrogen can also be used for EOR gas injection and pure water can also be used for water injection (Kapteijn et al., 2012).
4. CO₂ Gas Injection and WAG (Water Alternating Gas) Injection

4.1. Why do we use CO₂ for gas injection

There are 2 main features of CO₂ as injection gas for EOR process; density and viscosity. At high pressure above 80 bars (1160 psi) CO₂ is in supercritical phase with the density around 0.6-0.9 g/cm³ (Figure 4) which is very close to liquid and much higher than CH₄ or N₂ gas which can lead to less gravity segregation. The viscosity of CO₂ at this condition is around 0.045-0.08 cP (Figure 5) which is higher compared to CH₄ or N₂ and may lead to less gas fingering, but the CO₂ viscosity is still significantly lower than oil so it still can help to reduce oil viscosity if the CO₂ is dissolved in the oil which can increase the oil mobility and improve recovery (Jarrell et al., 2002).

Another good feature of CO₂ as injection gas is that it is easier to achieve miscibility with CO₂ compare to CH₄. It can be seen from Figure 6 that with the same temperature, same pressure and same oil composition, the two phase envelope with CO₂ as injection gas is much smaller than the two phase envelope of CH₄, so with CO₂ injection it is possible to achieve multi contact miscibility which required either one of the injected gas or the oil composition to be located on the right side of the critical tie line while with CH₄ injection the oil composition is located exactly at the critical tie line which means it is more difficult to achieve miscibility (Stalkup, 1983).

![Figure 4 CO₂, CH₄ and N₂ densities at 105 F (Jarrell et al., 2002)](image-url)
Figure 5 CO$_2$, CH$_4$ and N$_2$ viscosities at 105 F (Jarrell et al., 2002)

Figure 6 Comparison of miscibility condition of CO$_2$ and CH$_4$ with same pressure, temperature and oil composition (Stalkup, 1983)
4.2. Miscible and immiscible flood

The condition where CO₂ and oil become one phase is called miscible condition and the minimum pressure to achieve it is called MMP (Minimum Miscibility Pressure), usually it is determined by a slim tube test. Miscible CO₂ injection will have the most advantageous effect since the CO₂ will become one phase with oil which will reduce the interfacial tension to almost zero and subsequently we can reduce residual oil saturation to a very low number. In some cases the MMP can’t be reached due to certain conditions e.g; upper limit on pressure for injection well to keep injection pressure below the reservoir fracture pressure or well pressure limit, but nevertheless the CO₂ can still be injected in an immiscible condition where the gas and oil are still forming two phase and there is still an interface between them. This condition can still be beneficial to increase the oil production because the component exchange between oil and gas is still happen. The component exchange is causing oil swelling thus increasing oil saturation and also reducing oil viscosity which will increase the mobility of the oil resulting in more movable and recoverable oil (Schulte, 2012). The combination of the oil swelling and viscosity reduction can help to improve the displacement efficiency by reducing the residual oil saturation lower than $S_{orw}$ (residual oil saturation after waterflood). Improvement of the displacement efficiency also comes from the additional oil production which is previously immobile in the reservoir due to wettability and interfacial tension effect but now some parts of that immobile oil can be recovered due to the vaporization of the intermediate components from the oil to the injected CO₂ (Ghaderi et al., 2012).

Miscibility is a function of reservoir pressure, reservoir temperature and composition of the oil and the injected gas. Lower temperature will reduce the MMP but since usually the reservoir is considered to be in an isothermal condition then the pressure is more important than the temperature. Increasing pressure will
help the oil to dissolve more CO$_2$ and more components from oil can be vaporized by CO$_2$ so it will be easier to achieve miscibility (Jarrell et al., 2002).

This condition can be pictured in the ternary diagram where the two phase envelope size in the ternary diagram will be reduced with increasing pressure so it is easier for the oil and CO$_2$ to reach miscibility. The grey zone is the two phase envelope with the lower pressure and the yellow zone is the two phase envelope with the higher pressure (Figure 8).

![Figure 8 Effect of pressure on the 2 phase envelope](image)

### 4.3. WAG (Water Alternating Gas) injection

The improvement in the displacement efficiency by gas injection often comes with low sweep efficiency due to the nature of gas injection which is generally result in an unstable displacement due to gravity segregation and viscous fingering which caused early gas breakthrough and reduced the macroscopic sweep efficiency. Injecting water alternately with gas can help to control the mobility of the gas because the water will limit fractional flow of gas due to the 3 phase effects of WAG (Esmaiel, 2007). The viscous fingering of pure gas injection can be seen in the top diagram in Figure 9 where the long fingers of the gas were developed while in the bottom picture water was injected alternately with gas resulting in less fingering and more stable displacement (Schulte, 2012).

The reduction in gas mobility by injecting water alternately with gas can be seen from the top view of the model from reservoir simulation in Figure 10 and 11. In Figure 10, pure gas injection was simulated and it showed gas breakthrough at 780 days while for WAG simulation in Figure 11 the gas breakthrough happened at 1440 days. Improvement in macroscopic sweep efficiency due to the reduction of gas mobility can be seen here. The pure gas injection only swept less part of the reservoir compared to WAG injection because in WAG water acted as gas mobility reducer so water will reduce the mobility of the gas and forced the gas to go sideways thus swept more oil and increased macroscopic sweep efficiency.
Figure 9: Comparison of Pure Gas Injection and WAG (Schulte, 2012)

Figure 10: Gas Breakthrough on Pure Gas Injection at 780 days (Areal view)
4.4. Important parameters in WAG injection

Different WAG parameters which can affect the result of WAG injection have been studied by various authors through operational case studies and reservoir simulations. The parameters are; injection rates and WAG cycle length for each injection phase (Al-Ghanim et al., 2009, Nieman et al., 1992 and Surguchev et al., 1992).

Among those WAG parameters we limit our optimization scope to well control parameters which chosen to be BHP (Bottom Hole Pressure) of the injector wells because it is the common well control parameters to be used in the reservoir simulation to simulate WAG injection and it is indirectly related with the injection rates.
5. Field X – Introduction and Preliminary Run

The Ensemble Optimization for CO₂ WAG injection was done in anonymous field X which has an aquifer on the northern part of the field. The porosity and permeability in this field are ranging from 0 to 23% and from 0 to 2,300 mD.

This field has been produced under primary production and water injection for 40 years and the model is updated based on the history match using production data. There are 4 main zones in this field, where the uppermost layer consists of tight rock with a low permeability. This layer was therefore made inactive in the dynamic model. The second and third layers form the main reservoirs on this field, namely Reservoir A and Reservoir B which is connected vertically. The bottom layer mostly consists of water. Reservoir B has higher average permeability but it also has higher degree of heterogeneity compared to the reservoir A as can be seen in the permeability map in Figure 12. Figure 13 displayed the cross section of the permeability map penetrated by well P4.

This field contains under-saturated light oil with an API density of 30, hydrocarbon saturation pressure of 130 bars and a reservoir pressure of 200 bars. The combination of under-saturated light oil makes this field a suitable target for gas injection because high degree of under saturation and high intermediate hydrocarbon components content in the oil will help to increase component exchange between oil and the injected gas. MMP for CO₂ injection is 300 bars. The rest of the fluid properties are GOR (Gas Oil Ratio) 70 m³/m³ and Bo (Oil Formation Volume Factor) 1.31. For the En-Opt run 18 existing wells were used with 9 wells act as a producers supported by 9 injectors in a peripheral injection pattern where the producers grouped at the center of the field surrounded by injectors on the peripheral area (Figure 14). These wells were selectively perforated to target the zones which still have high oil saturation.

The original STOIIP in this field was 8.52 million m³ (Figure 15) with current recovery factor of 28.3% (Figure 16). The aim was to find the optimum well control parameters to economically produce the remaining oil to get the highest NPV.

The detailed data of this field can be seen in Table 1.

As a preliminary run, 3 cases were compared to find the best method to further develop this field. Those 3 methods are waterflood, pure CO₂ injection and base case CO₂ WAG.
Figure 12 Field X Permeability Map

Figure 13 Cross Section of Permeability Map in Well P4
Figure 14 Well Distribution in Field X

Figure 15 Initial Oil Saturation
Figure 16 Current Oil Saturation after 40 years of Production (28.3% RF)

<table>
<thead>
<tr>
<th>Field &amp; Fluid Data</th>
</tr>
</thead>
<tbody>
<tr>
<td>Grid Blocks</td>
</tr>
<tr>
<td>Layers</td>
</tr>
<tr>
<td>Upper: Reservoir A</td>
</tr>
<tr>
<td>Lower: Reservoir B</td>
</tr>
<tr>
<td>Water Layer</td>
</tr>
<tr>
<td>Number of Components</td>
</tr>
<tr>
<td>Aquifer</td>
</tr>
<tr>
<td>Reference Depth</td>
</tr>
<tr>
<td>Porosity Range</td>
</tr>
<tr>
<td>Permeability Range</td>
</tr>
<tr>
<td>Current Res. Pressure</td>
</tr>
<tr>
<td>Psat</td>
</tr>
<tr>
<td>MMP (CO2)</td>
</tr>
<tr>
<td>Oil API</td>
</tr>
<tr>
<td>GOR @ Psat</td>
</tr>
<tr>
<td>Bo @ Psat</td>
</tr>
<tr>
<td>Years Produced</td>
</tr>
<tr>
<td>Initial STOIP</td>
</tr>
<tr>
<td>Remaining STOIP</td>
</tr>
<tr>
<td>Current RF</td>
</tr>
<tr>
<td>Number of Producers</td>
</tr>
<tr>
<td>Number of Injectors</td>
</tr>
</tbody>
</table>

| Table 1 Field and Fluid Data for Field X |
5.1 Preliminary Run; Waterflood VS Pure CO₂ Injection VS Base Case CO₂ WAG

These 3 cases were run with a maximum injection BHP of 265 bars, fixed production BHP of 180 bars and a well shut-in limit of maximum water cut 99%, maximum GOR 1800 m³/m³ and minimum oil rate of 1 m³/day. The CO₂ WAG in this preliminary run was done with fixed injection cycle of 6 months for both gas and water. All three of them were produced for 10 years.

The oil production rate was compared in Figure 17, it can be seen that pure CO₂ injection gave the highest production rate at the early time due to maximum contact of gas and oil leading to more component exchange resulting in more mobile oil. The production rate declined rapidly due to early gas breakthrough which hampered the production (Figure 18). Waterflood only gave low production and also declined rapidly because of high water cut problems on the production wells (Figure 19).

Compared to other methods, CO₂ WAG gave the best result in terms of oil production rate supported by controlled GOR (Gas Oil Ratio) and water cut level so that production was kept at a high and sustainable level. In terms of recovery factor (Figure 20) it is clear that CO₂ WAG is the best option to develop this field with a recovery factor of 54% which is higher than pure CO₂ injection with 49% and waterflood with 43%.

The GOR profile in Figure 18 shows the role of injecting water alternately with gas to control the mobility of the gas. It is clear from this comparison that injecting water in an alternating scheme with gas can increase the overall recovery factor by combining the improvement in displacement efficiency from gas injection and improvement in sweep efficiency by introducing water as mobility control agent for gas.

The oil saturation profile of each production method can be seen in Figures 21-23. It can be seen that gas injection gave lower S_{or} (Residual Oil Saturation) compared to the waterflood case but the stratification and the heterogeneity of the field still limit the overall sweep efficiency of the field leaving some oil behind in the field. WAG injection gave higher recovery factor compared to pure CO₂ injection because WAG injection swept more part of the reservoir compared to the pure CO₂ injection which mainly swept only top part of the reservoir due to gravity segregation.
Figure 17 Oil Production Rate on Waterflood VS Pure CO\textsubscript{2} Injection VS CO\textsubscript{2} WAG

Figure 18 Gas Oil Ratio on Waterflood VS Pure CO\textsubscript{2} Injection VS CO\textsubscript{2} WAG
Figure 19 Water Cut on Waterflood VS Pure CO₂ Injection VS CO₂ WAG

Figure 20 Recovery Factor on Waterflood VS Pure CO₂ Injection VS CO₂ WAG
Figure 21 Oil Saturation after Waterflood (RF 43%)

Figure 22 Oil Saturation after Pure CO₂ Injection (RF 49%)
Figure 23: Oil Saturation after CO₂ WAG Injection (RF 54%)
6. CO₂ WAG EOR Run in Field X

From the preliminary run in Section 5, it was clear that the CO₂ WAG injection is the best method to develop this field compared to waterflood and pure CO₂ injection. This section discusses the further improvement of the CO₂ WAG injection in this field by applying the Ensemble Optimization method to optimized the injection BHP to achieve better NPV.

The optimization run were simulated for 10 years of production under a fixed WAG ratio of 6 months alternating injection between water and gas. Water and gas were injected from 9 injector wells in peripheral pattern while the 9 production wells were located at the center of the field. The well shut-in criteria were a maximum water cut of 99%, maximum gas oil ratio of 1800 m³/m³ and minimum oil production rate of 1 m³/day.

Control parameters for the En-Opt were chosen to be the injection BHP with the range of 200 – 265 bars and the initial injection BHP at the maximum point of 265 bars all the time. For this run, the BHP on the production side was kept fixed at 180 bars. All of the injector wells were grouped together into 1 injector group. This arrangement resulted in 20 numbers of controls. 20 samples were used in every iteration (Table 2).

<table>
<thead>
<tr>
<th>Control Parameter</th>
<th>BHP (Bottom Hole Pressure)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Group of Wells</td>
<td>Injector (IE)</td>
</tr>
<tr>
<td>Initial Injection BHP</td>
<td>265 bars</td>
</tr>
<tr>
<td>Range of Injection BHP</td>
<td>200 - 265 bars</td>
</tr>
<tr>
<td>Simulation End Time</td>
<td>3600 days</td>
</tr>
<tr>
<td>WAG Cycles</td>
<td>20 cycles</td>
</tr>
<tr>
<td>Total Number of Controls</td>
<td>20</td>
</tr>
<tr>
<td>Number of Samples</td>
<td>20</td>
</tr>
<tr>
<td>Standard Deviation</td>
<td>7</td>
</tr>
<tr>
<td>Initial Trust Region Size</td>
<td>0.1</td>
</tr>
<tr>
<td>Max. Trust Region Size</td>
<td>0.1</td>
</tr>
<tr>
<td>Trust Ratio 1</td>
<td>0.0001</td>
</tr>
<tr>
<td>Trust Ratio 2</td>
<td>0.1</td>
</tr>
<tr>
<td>Trust Region Contraction Factor</td>
<td>0.5</td>
</tr>
<tr>
<td>Trust Region Expansion Factor</td>
<td>2</td>
</tr>
</tbody>
</table>

Table 2 En-Opt Data for CO₂ WAG EOR run in Field X

6.1. Pricing for Objective Function Calculation

For this optimization run, oil price \( r_o \) of $80/STB were used and for the rest of the components namely cost of produced water, cost of injected water, cost of produced gas and cost of injected gas the cost were based on the Trigen plant investment. The numbers are \( r_{wp} = $1.2/bbl \), \( r_{wi} = $1/bbl \), \( r_{pg} = $0.35/MSCF \) and \( r_{gi} = $1.47/MSCF \). 10% discount factor was used for this case.
6.2. Optimization Result

The optimized case contributed $30 million incremental NPV or equivalent to 4% increase in objective function compared to the base case after 9 iterations (Figure 24). The incremental NPV came from the strategy to reduce the injection BHP during first and second water injection and maximize the BHP on the first, second and third gas injection, at the later stage the gas injection BHP were reduced and the water injection BHP were maximized (Figure 25 and Table 4). This strategy resulted in lower water injection rate at the first two cycle to maximized the amount of injected gas on the first, second and third cycle to have full benefit of the gas injection and then reduced the gas injection and maximized the amount of injected water on the next cycle (Figure 26 and 27).

This strategy was meant to produce more oil upfront by having more gas contacted the oil to increase the component exchange between gas and oil which at the end helped to increase the production while at the later time the optimizer reduced the gas injection and maximized water injection.

High gas injection rate at early time was beneficial for early oil production but on the other side it also has a significant effect on increasing GOR, the optimized case handled this problem by reducing gas injection later on and increasing water injection to have better control on GOR and also maximized sweep by water injection (Figure 28 and 29).

Higher NPV in the optimized case came from the increase in total oil production by 100,000 m$^3$ (Figure 30) equivalent to increase in the recovery factor by 1% (Figure 31). Another significant contributor to the increase in NPV is the improvement in the net CO$_2$ utilization from 4.8 MSCF/stb in the base case to 2.75 MSCF/stb in the optimized case, the bottom line is the optimized case makes better use of CO$_2$ compared to the base case.

### Table 3 Pricing Data

<table>
<thead>
<tr>
<th>Pricing</th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil Price</td>
<td>80</td>
<td>$/bbl</td>
</tr>
<tr>
<td>Produced Water Cost (Opex)</td>
<td>1.2</td>
<td>$/bbl</td>
</tr>
<tr>
<td>Injected Water Cost (Opex)</td>
<td>1</td>
<td>$/bbl</td>
</tr>
<tr>
<td>Produced Gas Cost (Opex)</td>
<td>0.35</td>
<td>$/MSCF</td>
</tr>
<tr>
<td>Injected Gas Cost (Opex)</td>
<td>1.47</td>
<td>$/MSCF</td>
</tr>
<tr>
<td>Discount Factor</td>
<td>10</td>
<td>%</td>
</tr>
</tbody>
</table>
Figure 24 NPV Result for CO₂ WAG EOR run in Field X

$30 million gain

Figure 25 Graphical Strategy for CO₂ WAG EOR run in Field X
<table>
<thead>
<tr>
<th>Time (days)</th>
<th>Optimized BHP (psi)</th>
<th>Initial BHP (psi)</th>
<th>Fluid</th>
</tr>
</thead>
<tbody>
<tr>
<td>180</td>
<td>231</td>
<td>265</td>
<td>Water</td>
</tr>
<tr>
<td>360</td>
<td>265</td>
<td>265</td>
<td>Gas</td>
</tr>
<tr>
<td>540</td>
<td>231</td>
<td>265</td>
<td>Water</td>
</tr>
<tr>
<td>720</td>
<td>265</td>
<td>265</td>
<td>Gas</td>
</tr>
<tr>
<td>900</td>
<td>263</td>
<td>265</td>
<td>Water</td>
</tr>
<tr>
<td>1080</td>
<td>260</td>
<td>265</td>
<td>Gas</td>
</tr>
<tr>
<td>1260</td>
<td>265</td>
<td>265</td>
<td>Water</td>
</tr>
<tr>
<td>1440</td>
<td>234</td>
<td>265</td>
<td>Gas</td>
</tr>
<tr>
<td>1620</td>
<td>265</td>
<td>265</td>
<td>Water</td>
</tr>
<tr>
<td>1800</td>
<td>231</td>
<td>265</td>
<td>Gas</td>
</tr>
<tr>
<td>1980</td>
<td>263</td>
<td>265</td>
<td>Water</td>
</tr>
<tr>
<td>2160</td>
<td>234</td>
<td>265</td>
<td>Gas</td>
</tr>
<tr>
<td>2340</td>
<td>260</td>
<td>265</td>
<td>Water</td>
</tr>
<tr>
<td>2520</td>
<td>234</td>
<td>265</td>
<td>Gas</td>
</tr>
<tr>
<td>2700</td>
<td>263</td>
<td>265</td>
<td>Water</td>
</tr>
<tr>
<td>2880</td>
<td>241</td>
<td>265</td>
<td>Gas</td>
</tr>
<tr>
<td>3060</td>
<td>234</td>
<td>265</td>
<td>Water</td>
</tr>
<tr>
<td>3240</td>
<td>244</td>
<td>265</td>
<td>Gas</td>
</tr>
<tr>
<td>3420</td>
<td>250</td>
<td>265</td>
<td>Water</td>
</tr>
<tr>
<td>3600</td>
<td>231</td>
<td>265</td>
<td>Gas</td>
</tr>
</tbody>
</table>

Table 4 Detailed Strategy for CO$_2$ WAG EOR run in Field X

[Graph showing water injection rate for CO$_2$ WAG EOR run in Field X]

Less Water Earlier
More Water Later
Reduce Capex

Figure 26 Water Injection Rate for CO$_2$ WAG EOR run in Field X
More Gas Earlier
Less Gas Later

Figure 27 Gas Injection Rate for CO₂ WAG EOR run in Field X

High GOR Earlier
Controlled Low GOR Later

Figure 28 Gas Oil Ratio for CO₂ WAG EOR run in Field X
Figure 29 Water Cut for CO$_2$ WAG EOR run in Field X

Figure 30 Total Oil Production for CO$_2$ WAG EOR run in Field X

Increase of 100 thousand m$^3$
6.3. Comparison of Optimized WAG, Base Case WAG, Pure Gas Injection and Waterflood on Field X for 10 years of Run.

This final chapter in this section compares all of the alternatives on how to maximize the economic value of this field. The best parameter to compare it is the economic calculation which is the discounted NPV (Figure 32) is using the same pricing method as described in section 6.1.

It can be seen that the optimized WAG is superior compared to the other alternatives in terms of discounted NPV by giving the highest NPV of $787 million compared to the discounted NPV of the base case WAG of $757 million while the pure CO$_2$ injection and waterflood gave significantly lower discounted NPV of $569 million and $537 million respectively.
Figure 32 Discounted NPV 10% Between Optimized WAG, Base Case WAG, Pure Gas Injection and Waterflood
7. Conclusion

1. En-Opt method generates a better operating strategy compared to the base case strategy for the CO₂ WAG EOR in field X by increasing the oil production and improving the net CO₂ utilization resulting in $30 million incremental NPV equal to 4% increase of the NPV.

2. The optimized CO₂ WAG strategy of high gas injection at the early time and high water injection at later time is beneficial to increase the recovery factor, the net CO₂ utilization and the discounted NPV of the CO₂ WAG EOR in field X.

3. Pure CO₂ injection is beneficial compared to waterflood to increase the oil production but the uncontrolled mobility of the CO₂ gave negative effect of high GOR and low recovery factor compared to the CO₂ WAG.

4. Injecting water in the CO₂ WAG scheme helped to control CO₂ mobility resulting in lower and controlled GOR which is beneficial to increase the recovery factor compared to pure CO₂ injection.

5. Optimized CO₂ WAG is the best method to be applied in field X compared the other three production methods indicated by the highest NPV of $787 million compared to the NPV of the base case WAG of $757 million while the pure CO₂ injection and waterflood gave significantly lower NPV of $569 million and $537 million respectively.

6. Introducing water and gas cycle injection length as the additional control parameters in the En-Opt besides the injection BHP is beneficial to increase the objective function further compared to controlling the injection BHP only. Refer to Appendix C where the run with the injection length and injection BHP as the control parameters gave $93.41 million incremental NPV while the run with only injection BHP as the control parameter gave $9 million incremental NPV when compared to the same base case.

7. The results in the Chapter 6 and the Appendix C confirmed our hypothesis that the application En-Opt method helped to increase the discounted NPV in the CO₂ WAG EOR project.
8. Recommendations and Way Forward

It is interesting to see that the injection strategy in the optimized result tried to maximize gas injection while reducing water injection during early times and reversing this strategy during later times. This strategy is mimicking to some extent the effect of tapered WAG injection by always injecting water and gas at the maximum BHP but starting with low WAG ratio (inject gas during longer time intervals and inject water with shorter time intervals) and increasing the WAG ratio over time. Such strategy was found to be beneficial to improve the project NPV by Pariani et al. (2002). This is one of the options to improve NPV further for the future run by injecting water and gas at maximum injection BHP and use En-Opt to find the optimum length of injection cycle for water and gas.

The optimized WAG case gave a recovery factor of 55% mainly due to low sweep efficiency because the gas and water injection mainly swept the top parts and high permeability zones of the field (Figure 33). There are still other opportunities to be explored and optimized for this field such as well pattern and well spacing optimization including the number and the location of the newly drilled wells to sweep more part of the reservoir.

Figure 33 Oil Saturation after Optimized WAG Injection (RF 55%)
REFERENCES


List of Figures

Figure 1: En-Opt Flow Chart
Figure 2: Trigen Principles (Kapteijn et al., 2012)
Figure 3: Trigen Based Value Chain

Figure 4: CO₂, CH₄ and N₂ densities at 105 F (Jarrell et al., 2002)
Figure 5: CO₂, CH₄ and N₂ viscosities at 105 F (Jarrell et al., 2002)
Figure 6: Comparison of miscibility condition of CO₂ and CH₄ with same pressure, temperature and oil composition (Stalkup, 1983)
Figure 7: Immiscible and Miscible Condition (Schulte, 2012)
Figure 8: Effect of pressure on the 2 phase envelope
Figure 9: Comparison of Pure Gas Injection and WAG (Schulte, 2012)
Figure 10: Gas Breakthrough on Pure Gas Injection at 780 days (Areal view)
Figure 11: Gas Breakthrough on WAG at 1440 days (Areal view)
Figure 12: Field X Permeability Map
Figure 13: Cross Section of Permeability Map in Well P4
Figure 14: Well Distribution in Field X
Figure 15: Initial Oil Saturation
Figure 16: Current Oil Saturation after 40 years of Production (28.3% RF)
Figure 17: Oil Production Rate on Waterflood VS Pure CO₂ Injection VS CO₂ WAG
Figure 18: Gas Oil Ratio on Waterflood VS Pure CO₂ Injection VS CO₂ WAG
Figure 19: Water Cut on Waterflood VS Pure CO₂ Injection VS CO₂ WAG
Figure 20: Recovery Factor on Waterflood VS Pure CO₂ Injection VS CO₂ WAG
Figure 21: Oil Saturation after Waterflood (RF 43%)
Figure 22: Oil Saturation after Pure CO₂ Injection (RF 49%)
Figure 23: Oil Saturation after CO₂ WAG Injection (RF 54%)
Figure 24: NPV Result for CO₂ WAG EOR run in Field X
Figure 25: Graphical Strategy for CO₂ WAG EOR run in Field X
Figure 26: Water Injection Rate for CO₂ WAG EOR run in Field X
Figure 27: Gas Injection Rate for CO₂ WAG EOR run in Field X
Figure 28: Gas Oil Ratio for CO₂ WAG EOR run in Field X
Figure 29: Water Cut for CO₂ WAG EOR run in Field X
Figure 30: Total Oil Production for CO₂ WAG EOR run in Field X
Figure 31: Recovery Factor CO₂ WAG EOR run in Field X
Figure 32: Discounted NPV 10% Between Optimized WAG, Base Case WAG, Pure Gas Injection and Waterflood

Figure 33: Oil Saturation after Optimized WAG Injection (RF 55%)

Figure B1: Switching Time Diagram

Figure B2: Time Length Diagram

Figure C1: Field Y

Figure C2: Result of WAG Run Field-Y WAG Run Field Y (BHP as control parameters)

Figure C3: Graphical Strategy of WAG Run Field-Y (BHP as control parameters)

Figure C4: Total Oil Production of WAG Run Field-Y (BHP as control parameters)

Figure C5: Graphical Strategy of WAG Run Field-Y (Injection Length and BHP as control parameters)

Figure C6: Detailed of WAG Run Field-Y WAG Run Field Y
                        (Injection Length and BHP as control parameters)

Figure C7: Total Oil Production of WAG Run Field-Y WAG Run Field Y
                        (Injection Length and BHP as control parameters)
List of Tables

**Table 1**: Field and Fluid Data for Field X

**Table 2**: En-Opt Data for CO₂ WAG EOR run in Field X

**Table 3**: Pricing Data

**Table 4**: Detailed Strategy for CO₂ WAG EOR run in Field X

**Table C1**: Field and Fluid Data for Field Y

**Table C2**: En-Opt Data for WAG Run Field Y (BHP as control parameters)

**Table C3**: Detailed Strategy of WAG Run Field-Y (BHP as control parameters)

**Table C4**: En-Opt Data for WAG Run Field Y (Injection Length and BHP as control parameters)

**Table C5**: Detailed of WAG Run Field-Y WAG Run Field Y (Injection Length and BHP as control parameters)
Appendix A: Additional Runs using En-Opt

1. WAG Optimization on simple homogenous reservoir with 5 spot pattern (1 Producer 4 Injectors) with Injection BHP control on the range of 4000 – 4500 psi and initial BHP of 4250 psi. Only take oil into account. Improvement in NPV = $ 66.24 million gain.

2. WAG Optimization on simple homogenous reservoir with 5 spot pattern (1 Producer 4 Injectors) with Injection BHP control on the range of 4000 – 4500 psi and initial BHP of 4250 psi. Pricing using table 3. Improvement in NPV = $ 27.68 million gain.

3. WAG Optimization on simple homogenous reservoir with 5 spot pattern (1 Producer 4 Injectors) with Injection BHP control on the range of 4000 – 4500 psi and initial BHP of 4500 psi. Only take oil into account. Improvement in NPV = $ 19.79 million gain.

4. WAG Optimization on simple homogenous reservoir with 5 spot pattern (1 Producer 4 Injectors) with Injection BHP control on the range of 4000 – 4500 psi and initial BHP of 4500 psi. Pricing using table 3. Improvement in NPV = $ 9 million gain.

5. WAG Optimization on simple homogenous reservoir with 5 spot pattern (1 Producer 4 Injectors) with Injection cycle length and Injection BHP control on the range of 4000 – 4500 psi and initial BHP of 4500 psi. Pricing using table 3. Improvement in NPV = $ 93.41 million gain. This is the best result compared to the other 4 runs so controlling time and injection pressure will give higher NPV compared to single control of injection BHP.


Appendix B: Dynamic Time Bounds Constraints for Half Cycle Injection Length of water or CO₂

For this CO₂ WAG application the switching time from water to CO₂ injection and water & CO₂ injection rate/BHP were used as the control parameters. The minimum and maximum bound for each control parameter have to be specified. For injection rate or injection BHP the maximum bound and minimum bound are simple and depend on several factors such as the compressor and pump capacity for gas and water or the fracture pressure of the reservoir and well pressure limit which means that the maximum and minimum bounds are fixed numbers which are easier to be treated in the optimization code.

![Switching Time Diagram](image)

Figure B1 Switching Time Diagram

Special attention has to be paid to the switching time as control parameter because the maximum and minimum bounds will be different for each injection cycle and for every iteration. The important part to be focused on time controls is the prevention of overlapping during the update of the control parameter.

Another consideration is the minimum time lapse for 1 phase injection (half cycle) of water or CO₂ which depend on the several factors such as operational condition and feasibility; we will state this minimum time lapse as $\Delta t_{\text{min}}$. 
Note:
\( \alpha_i \) = step length
\( g_i \) = gradient
\( u_i \) = control parameter (switching time)
\( a_i \) = minimum bounds for time \( i \)
\( b_i \) = maximum bounds for time \( i \)
\( \Delta t_{\text{min}} \) = minimum time lapse
\( t_0 \) = initial time
\( t_{\text{end}} \) = end time

Updated control scheme
\[
    u_{i+1} = u_i + \alpha_i \, g_i ,
\]
with
\[
    \alpha_i \geq 0 ,
\]
and
\[
    a_i < u_i < b_i .
\]

For the injection rate or injection BHP this constraint is easy to implement with
\[
    Q_{\text{min}} < Q < Q_{\text{max}} \text{ or } BHP_{\text{min}} < BHP < BHP_{\text{max}} ,
\]
while for the switching time, the problem is more complicated since it has to satisfy the
\( a_i < u_i < b_i \) constraint as well as \( t_i \leq t_{i+1} + \Delta t_{\text{min}} \). To fulfill the constraint requirement and to prevent overlapping, the algorithm for the switching time update was derived below.

Figure B2 Time Length Diagram
For the minimum and maximum bound
\[ a_i = \left( \frac{t_i + t_{i-1}}{2} \right) + \frac{\Delta t_{\text{min}}}{2}, \]  
and
\[ b_i = \left( \frac{t_i + t_{i+1}}{2} \right) - \frac{\Delta t_{\text{min}}}{2}, \]

with special rules for the control minimum for first time step
\[ a_i = t_0 + \Delta t_{\text{min}}, \]
and for the control maximum for last time step
\[ b_i = t_{\text{end}} - \Delta t_{\text{min}}. \]
Appendix C: Comparison of En-Opt Run with Time and Injection BHP as Control Parameters Compared to En-Opt Run with Injection BHP only as Control Parameters

C.1. Field Y

This field consists of three layers with 49 (7x7) grid blocks horizontally covering 2500 ft of total distance in X and Y direction for each grid block and thickness of 20, 30 and 50 ft vertically. Permeability ranging from 2-4 mD with 4 mD in first layer and 2 mD and 3 mD for second and third layer. STOIP in this field is 27.1 million barrel with initial reservoir pressure of 4000 psi.

Production will come from a 5 spot pattern with 1 producer well in the middle and 4 injector wells in the corner. The injection wells were grouped together in one group.

![Figure C1 Field Y](image_url)
### C.2 WAG Run with Only Injection BHP as Control Parameters

#### C.2.1 En-Opt and Pricing Data

For this case, the field will be produced for 5400 days under CO₂ WAG injection with constant injection length for both water and gas cycle of 180 days. The control parameter is BHP on the injector wells ranging from 4050 – 4500 psi with initial BHP of 4500 psi and the BHP are allowed to change every 6 months. BHP on the producer side is kept constant of 1000 psi. This arrangement resulted in total 30 numbers of controls. 30 samples were used in every iteration on this run. The result of the optimized case will be compared with the base case of fixed injection BHP of 4500 psi for all cycles with the same fixed water and gas injection length of 180 days.
The objective function is the discounted NPV with 10% discount factor as in Table 3 (Section 6.1).

C.2.2 Results

The optimized strategy resulted in $9 million incremental NPV from 35 iterations (Figure C2) which came from the injection strategy by reducing water injection BHP while maximizing gas injection BHP during early time and reversed it close to the end of production life (Figure C3 and Table C3). This strategy allowed more contact between gas and oil in the optimized case which is beneficial to increase oil production from 7.4 million bbl in the base case to 7.6 million bbl in the optimized case (Figure C4). The increase in the oil production is the main reason for the increase in the objective function since the oil price is outweigh all of the other costs.

<table>
<thead>
<tr>
<th>Control Parameter</th>
<th>BHP (Bottom Hole Pressure)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Group of Wells</td>
<td>INJ (4 Injectors)</td>
</tr>
<tr>
<td>Initial Injection BHP</td>
<td>4500 psi</td>
</tr>
<tr>
<td>Range of Injection BHP</td>
<td>4050-4500 psi</td>
</tr>
<tr>
<td>Simulation End Time</td>
<td>5400 days</td>
</tr>
<tr>
<td>WAG Cycles</td>
<td>30 cycles</td>
</tr>
<tr>
<td>Total Number of Controls</td>
<td>30</td>
</tr>
<tr>
<td>Number of Samples</td>
<td>30</td>
</tr>
<tr>
<td>Standard Deviation</td>
<td>50</td>
</tr>
<tr>
<td>Initial Trust Region Size</td>
<td>0.1</td>
</tr>
<tr>
<td>Max. Trust Region Size</td>
<td>0.1</td>
</tr>
<tr>
<td>Trust Ratio 1</td>
<td>0.0001</td>
</tr>
<tr>
<td>Trust Ratio 2</td>
<td>0.1</td>
</tr>
<tr>
<td>Trust Region Contraction Factor</td>
<td>0.5</td>
</tr>
<tr>
<td>Trust Region Expansion Factor</td>
<td>2</td>
</tr>
</tbody>
</table>

Table C2 En-Opt Run Data for WAG Run Field Y (BHP as control parameters)
$9 million gain

Figure C3 Graphical Strategy of WAG Run Field-Y (BHP as control parameters)
<table>
<thead>
<tr>
<th>Time (days)</th>
<th>Optimized BHP (psi)</th>
<th>Initial BHP (psi)</th>
<th>Fluid</th>
</tr>
</thead>
<tbody>
<tr>
<td>180</td>
<td>4050</td>
<td>4500</td>
<td>Water</td>
</tr>
<tr>
<td>360</td>
<td>4500</td>
<td>4500</td>
<td>Gas</td>
</tr>
<tr>
<td>540</td>
<td>4050</td>
<td>4500</td>
<td>Water</td>
</tr>
<tr>
<td>720</td>
<td>4500</td>
<td>4500</td>
<td>Gas</td>
</tr>
<tr>
<td>900</td>
<td>4050</td>
<td>4500</td>
<td>Water</td>
</tr>
<tr>
<td>1080</td>
<td>4500</td>
<td>4500</td>
<td>Gas</td>
</tr>
<tr>
<td>1260</td>
<td>4057</td>
<td>4500</td>
<td>Water</td>
</tr>
<tr>
<td>1440</td>
<td>4500</td>
<td>4500</td>
<td>Gas</td>
</tr>
<tr>
<td>1620</td>
<td>4228</td>
<td>4500</td>
<td>Water</td>
</tr>
<tr>
<td>1800</td>
<td>4500</td>
<td>4500</td>
<td>Gas</td>
</tr>
<tr>
<td>1980</td>
<td>4216</td>
<td>4500</td>
<td>Water</td>
</tr>
<tr>
<td>2160</td>
<td>4500</td>
<td>4500</td>
<td>Gas</td>
</tr>
<tr>
<td>2340</td>
<td>4225</td>
<td>4500</td>
<td>Water</td>
</tr>
<tr>
<td>2520</td>
<td>4500</td>
<td>4500</td>
<td>Gas</td>
</tr>
<tr>
<td>2700</td>
<td>4306</td>
<td>4500</td>
<td>Water</td>
</tr>
<tr>
<td>2880</td>
<td>4500</td>
<td>4500</td>
<td>Gas</td>
</tr>
<tr>
<td>3060</td>
<td>4461</td>
<td>4500</td>
<td>Water</td>
</tr>
<tr>
<td>3240</td>
<td>4498</td>
<td>4500</td>
<td>Gas</td>
</tr>
<tr>
<td>3420</td>
<td>4162</td>
<td>4500</td>
<td>Water</td>
</tr>
<tr>
<td>3600</td>
<td>4493</td>
<td>4500</td>
<td>Gas</td>
</tr>
<tr>
<td>3780</td>
<td>4450</td>
<td>4500</td>
<td>Water</td>
</tr>
<tr>
<td>3960</td>
<td>4497</td>
<td>4500</td>
<td>Gas</td>
</tr>
<tr>
<td>4140</td>
<td>4500</td>
<td>4500</td>
<td>Water</td>
</tr>
<tr>
<td>4320</td>
<td>4499</td>
<td>4500</td>
<td>Gas</td>
</tr>
<tr>
<td>4500</td>
<td>4376</td>
<td>4500</td>
<td>Water</td>
</tr>
<tr>
<td>4680</td>
<td>4348</td>
<td>4500</td>
<td>Gas</td>
</tr>
<tr>
<td>4860</td>
<td>4265</td>
<td>4500</td>
<td>Water</td>
</tr>
<tr>
<td>5040</td>
<td>4091</td>
<td>4500</td>
<td>Gas</td>
</tr>
<tr>
<td>5220</td>
<td>4147</td>
<td>4500</td>
<td>Water</td>
</tr>
<tr>
<td>5400</td>
<td>4075</td>
<td>4500</td>
<td>Gas</td>
</tr>
</tbody>
</table>

Table C3 Detailed Strategy of WAG Run Field-Y (BHP as control parameters)
C.3 WAG Run with Injection Cycle Length and Injection BHP as Control Parameters

C.3.1 En-Opt and Pricing Data

For this case, the field will be produced for 5400 days under CO$_2$ WAG injection with the length of water and gas injection cycle and the injection BHP as the control parameters ranging from 4050 – 4500 psi. The number of cycles were made fixed with 30 cycles but the length of each cycle can be vary to find the optimum parameters. The BHP on the producer side is kept constant of 1000 psi. This arrangement resulted in total 59 numbers of controls. 30 samples were used in every iteration on this run. The result of the optimized case will be compared with the base case of fixed injection BHP of 4500 psi for all cycles with the same fixed water and gas injection length of 180 days.
The objective function is the discounted NPV with 10% discount factor as in Table 3 (Section 6.1).

C.3.2 Results

The optimized strategy resulted in $93 million incremental NPV from 22 iterations (Figure C5) which came from the injection strategy by reducing the BHP and injection length during water injection while maximizing gas injection BHP and gas cycle injection length during early time and reversed it in the middle of the production life until the end of production (Figure C6 and Table C4). This optimized strategy allowed maximum contact between gas and oil in the early time to produce as much oil as possible earlier and when the gas started to breakthrough then the optimizer started to increase the water injection to control the gas mobility by increasing the water cycle injection length. This strategy gave significant increase in oil production from 7.4 million bbl in the base case to 9.6 million bbl in the optimized case (Figure C7). The increase in the oil production is the main reason for the increase in the objective function since the oil price is outweigh all of the other costs.
Figure C5 Graphical Strategy of WAG Run Field-Y (Injection Length and BHP as control parameters)

Figure C6 Detailed of WAG Run Field-Y WAG Run Field Y (Injection Length and BHP as control parameters)
<table>
<thead>
<tr>
<th>Time (days)</th>
<th>Time Interval (days)</th>
<th>Optimized BHP (psi)</th>
<th>Initial BHP (psi)</th>
<th>Fluid</th>
</tr>
</thead>
<tbody>
<tr>
<td>30</td>
<td>30</td>
<td>4192</td>
<td>4500</td>
<td>Water</td>
</tr>
<tr>
<td>420</td>
<td>390</td>
<td>4498</td>
<td>4500</td>
<td>Gas</td>
</tr>
<tr>
<td>450</td>
<td>30</td>
<td>4483</td>
<td>4500</td>
<td>Water</td>
</tr>
<tr>
<td>769</td>
<td>319</td>
<td>4500</td>
<td>4500</td>
<td>Gas</td>
</tr>
<tr>
<td>800</td>
<td>30</td>
<td>4494</td>
<td>4500</td>
<td>Water</td>
</tr>
<tr>
<td>1159</td>
<td>360</td>
<td>4500</td>
<td>4500</td>
<td>Gas</td>
</tr>
<tr>
<td>1189</td>
<td>30</td>
<td>4422</td>
<td>4500</td>
<td>Water</td>
</tr>
<tr>
<td>1525</td>
<td>336</td>
<td>4486</td>
<td>4500</td>
<td>Gas</td>
</tr>
<tr>
<td>1555</td>
<td>30</td>
<td>4479</td>
<td>4500</td>
<td>Water</td>
</tr>
<tr>
<td>1873</td>
<td>318</td>
<td>4482</td>
<td>4500</td>
<td>Gas</td>
</tr>
<tr>
<td>1904</td>
<td>31</td>
<td>4485</td>
<td>4500</td>
<td>Water</td>
</tr>
<tr>
<td>2307</td>
<td>403</td>
<td>4464</td>
<td>4500</td>
<td>Gas</td>
</tr>
<tr>
<td>2339</td>
<td>32</td>
<td>4357</td>
<td>4500</td>
<td>Water</td>
</tr>
<tr>
<td>2526</td>
<td>187</td>
<td>4500</td>
<td>4500</td>
<td>Gas</td>
</tr>
<tr>
<td>2624</td>
<td>98</td>
<td>4370</td>
<td>4500</td>
<td>Water</td>
</tr>
<tr>
<td>2924</td>
<td>300</td>
<td>4211</td>
<td>4500</td>
<td>Gas</td>
</tr>
<tr>
<td>3028</td>
<td>104</td>
<td>4119</td>
<td>4500</td>
<td>Water</td>
</tr>
<tr>
<td>3168</td>
<td>140</td>
<td>4444</td>
<td>4500</td>
<td>Gas</td>
</tr>
<tr>
<td>3408</td>
<td>240</td>
<td>4351</td>
<td>4500</td>
<td>Water</td>
</tr>
<tr>
<td>3642</td>
<td>233</td>
<td>4500</td>
<td>4500</td>
<td>Gas</td>
</tr>
<tr>
<td>3811</td>
<td>170</td>
<td>4375</td>
<td>4500</td>
<td>Water</td>
</tr>
<tr>
<td>3999</td>
<td>188</td>
<td>4471</td>
<td>4500</td>
<td>Gas</td>
</tr>
<tr>
<td>4175</td>
<td>176</td>
<td>4379</td>
<td>4500</td>
<td>Water</td>
</tr>
<tr>
<td>4289</td>
<td>114</td>
<td>4465</td>
<td>4500</td>
<td>Gas</td>
</tr>
<tr>
<td>4551</td>
<td>262</td>
<td>4289</td>
<td>4500</td>
<td>Water</td>
</tr>
<tr>
<td>4730</td>
<td>179</td>
<td>4500</td>
<td>4500</td>
<td>Gas</td>
</tr>
<tr>
<td>4859</td>
<td>129</td>
<td>4471</td>
<td>4500</td>
<td>Water</td>
</tr>
<tr>
<td>5080</td>
<td>221</td>
<td>4489</td>
<td>4500</td>
<td>Gas</td>
</tr>
<tr>
<td>5313</td>
<td>233</td>
<td>4435</td>
<td>4500</td>
<td>Water</td>
</tr>
<tr>
<td>5400</td>
<td>87</td>
<td>4310</td>
<td>4500</td>
<td>Gas</td>
</tr>
</tbody>
</table>

Table C5 Detailed of WAG Run Field-Y WAG Run Field Y (Injection Length and BHP as control parameters)
Comparison Between Injection Length and BHP as Control Parameters VS BHP Only as Control Parameters

From the results of these two runs in Section C.2.2 and C.3.2 it is clear that using injection length as additional control parameters in the En-Opt run besides injection BHP is very beneficial for the economics of the project as shown by the increase in NPV of $93 million and 9.6 million bbl of total oil production in the run with injection length and injection BHP compared to increase in NPV of $9 million and 7.6 million bbl of total oil production in the run with only injection BHP as control parameters.

It is also interesting to see that the results in the Section C.2.2 and C.3.2 also confirmed that the optimized WAG strategy of field X in Section 6.2 by reducing water injection and maximizing gas injection during the early time and reversed it during later time is beneficial to improve the economics of the project shown by the increase in NPV.