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Thermal Simulation and Optimization of SAGD Process: Case Study on Surmont Pilot Project

Bao, Xia


master thesis

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Thermal Simulation and Optimization of SAGD Process: Case Study on Surmont Pilot Project

by

Xia Bao

A THESIS
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Abstract

Overlying top water and gas thief zones have a detrimental effect on the Steam-Assisted Gravity Drainage (SAGD) recovery process since steam penetrates into these zones which results in great heat loss. Due to the presence of these top thief zones, recovering bitumen by the SAGD process has become challenging for the Athabasca oil sands.

Numerical simulations, laboratory experiments and field production data have demonstrated that oil production tends to decrease as the depletion of top gas occurs; also, heat loss to the overlying thief zone will be more significant when a top water zone is present. Indeed, SAGD is a coupled geomechanical, thermal and fluid flow problem, and continuous steam injection in this process changes reservoir pore pressure and temperature, which can alter the effective stress in-situ. Therefore, to represent the physics of thermal flow and soil geomechanics, a coupled geomechanical simulation that solves the flow and stress equations simultaneously in the reservoir is crucial for modeling the SAGD process.

The objective of this study is to construct a 3D geostatistical model for a Surmont pilot and implement coupled geomechanical modeling for the SAGD process aiming at investigating the impact of dilation and thermal expansion on the surface subsidence and bitumen recovery. Reasonable history match of oil and water rates has been achieved and steam chamber profiles have been conformed to the field data from the observation wells. An Expanding Solvent Steam-Assisted Gravity Drainage (ES-SAGD) process has been investigated on a full field-based heterogeneous simulation model using an optimal solvent mixture. Finally, geomechanical effects on the ES-SAGD process are investigated through an iterative coupling approach.
Acknowledgements

First and foremost, I would like to thank my supervisor Dr. Zhangxing Chen for his teaching, support, contributions, encouragement, and guidance during this work. The simulation and modeling of heavy oil reservoirs I learned from him guided me throughout my graduate studies.

I thank the Reservoir Simulation Group members for their valuable discussion on the Surmont SAGD pilot project study.

Thanks go to Schlumberger for providing training and support in geomodeling and simulation packages (Petrel). Thanks CMG for providing the STARS and CMOST, which are the thermal simulator and optimization tool used in the thesis.
Dedication

This thesis is dedicated to my husband Hui Deng and my daughter Wanshu Deng for their love and encouragement.
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<td>Steam-Assisted Gravity Drainage</td>
</tr>
<tr>
<td>ES-SAGD</td>
<td>Expanding Solvent Steam-Assisted Gravity Drainage</td>
</tr>
<tr>
<td>OBIP</td>
<td>Original bitumen in place</td>
</tr>
<tr>
<td>BHP</td>
<td>Bottom hole pressure</td>
</tr>
<tr>
<td>SGS</td>
<td>Sequential Gaussian Simulation</td>
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<tr>
<td>SIS</td>
<td>Sequential indicator simulation</td>
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<td>IHS</td>
<td>Inclined Heterolithic Stratification</td>
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<tr>
<td>P10, P50 and P90</td>
<td>Probability distributions for the variables</td>
</tr>
<tr>
<td>BEVERHL</td>
<td>Beaver Hill formation</td>
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<tr>
<td>cSOR</td>
<td>Cumulative steam oil ratio (fraction)</td>
</tr>
<tr>
<td>GR</td>
<td>Gamma ray (API unit)</td>
</tr>
<tr>
<td>NPHI</td>
<td>Neutron porosity (fraction)</td>
</tr>
<tr>
<td>RHOB</td>
<td>Bulk density (gm/cc)</td>
</tr>
<tr>
<td>MOD_I</td>
<td>i-direction permeability multiplier</td>
</tr>
<tr>
<td>MOD_J</td>
<td>j-direction permeability multiplier</td>
</tr>
<tr>
<td>Kv/Kh</td>
<td>the vertical and horizontal permeability ratio</td>
</tr>
<tr>
<td>KRWIRO</td>
<td>the relative permeability to water at $S_w = 1 - S_{ow}$</td>
</tr>
<tr>
<td>KROCW</td>
<td>Relative permeability to oil at the connate</td>
</tr>
<tr>
<td></td>
<td>Water and zero gas saturation $S_w = 1 - S_{ow}$</td>
</tr>
<tr>
<td>DECE</td>
<td>Designed Exploration Controlled Evolution</td>
</tr>
<tr>
<td>Symbol</td>
<td>Definition</td>
</tr>
<tr>
<td>--------</td>
<td>------------</td>
</tr>
<tr>
<td>$Q_o$</td>
<td>Oil production rate</td>
</tr>
<tr>
<td>$\kappa$</td>
<td>Permeability</td>
</tr>
<tr>
<td>$\alpha$</td>
<td>Reservoir thermal diffusivity</td>
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<tr>
<td>$\phi$</td>
<td>Porosity</td>
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<tr>
<td>$\Delta S_o$</td>
<td>Initial oil saturation-residual oil saturation</td>
</tr>
<tr>
<td>$h_f$</td>
<td>Net pay</td>
</tr>
<tr>
<td>$m$</td>
<td>Dimensionless constant</td>
</tr>
<tr>
<td>$v_s$</td>
<td>Oil kinematic viscosity</td>
</tr>
<tr>
<td>$E$</td>
<td>Heat flux</td>
</tr>
<tr>
<td>$K_h$</td>
<td>Thermal conductivity</td>
</tr>
<tr>
<td>$\rho$</td>
<td>Density</td>
</tr>
<tr>
<td>$c$</td>
<td>Specific heat</td>
</tr>
<tr>
<td>$T_s$</td>
<td>Saturation temperature of steam</td>
</tr>
<tr>
<td>$T_R$</td>
<td>Reservoir temperature</td>
</tr>
<tr>
<td>$T_f$</td>
<td>Fluid temperature</td>
</tr>
<tr>
<td>$t_D$</td>
<td>Dimensionless time</td>
</tr>
<tr>
<td>$x_D$</td>
<td>Dimensionless distance</td>
</tr>
<tr>
<td>$M_s$</td>
<td>Formation heat capacity</td>
</tr>
<tr>
<td>$V_s$</td>
<td>Steam zone volume</td>
</tr>
</tbody>
</table>
\( M_{ob} \)  Heat capacity of overburden and underburden

\( k_{ob} \)  Thermal conductivity of overburden and underburden

\( \rho_f \)  Density

\( c_f \)  Specific heat of the injected fluid

\( i_f \)  Hot fluid injection rate

\( h_i \)  Net pay

\( Q_i \)  Heat injection rate

\( Q_{ob} \)  Heat loss rate to the overburden and underburden

\( Q_s \)  Heating rate of the rock and fluids to temperature \( T_s \)

\( i_{st} \)  Steam injection rate

\( h_w \)  Enthalpy of saturated water

\( f_{st} \)  Steam quality

\( L_v \)  Latent heat of vaporization

\( c_w \)  Specific heat of water

\( Q_{loss} \)  Cumulative heat loss

\( F_1 \)  Function of the dimensionless time

\( F_3 \)  Function of the dimensionless time

\( \text{erfc}(x) \)  Error function of \( x \)
\( t_c \)  
Critical time

\( t_{df} \)  
Dimensionless critical time

\( G_j \)  
Chemical potential of a component of a mixture

\( K_j \)  
The ratio of vapor concentration to liquid concentration at equilibrium

\( f_{sij} \)  
Fugacity of the component in gas phase

\( f_{ij} \)  
Fugacity of the component in liquid phase

\( \phi_j \)  
Fugacity coefficient

\( y_j \)  
The mole fraction of vapor

\( x_j \)  
The mole fraction of liquid

\( R \)  
Idea gas constant

\( V \)  
Volume of the gas

\( T \)  
Temperature of the gas

\( p \)  
Pressure of the gas

\( Z \)  
Compressibility factor

\( K \)  
Stiffness matrix

\( \delta \)  
Displacement vector

\( L \)  
Coupling matrix to flow unknowns

\( E \)  
Flow matrix

\( P \)  
Vector of reservoir unknowns

\( F \)  
Vector of force boundary conditions
$R$ Right hand side of the flow equations

$\Delta t$ Change over time step

$\phi^*$ Apparent porosity

$k_E$ Dimensionless young’s modulus

$k_B$ Dimensionless bulk modulus

$K_t$ The tangent modulus

$E_i$ The initial modulus

$E_t$ Tangential Young’s modulus

$B_m$ The tangential bulk modulus

$\nu$ Poisson’s ratio

$Pa$ Atmospheric pressure

$\sigma'_1, \sigma'_3$ Major and minor principal stresses

$\sigma'_r$ Reference stress ($\sigma'_r = \sigma'_3$)

$\sigma'_\text{dev}$ Deviatoric stress

$(\sigma'_1 - \sigma'_3)_f$ Deviatoric stress at failure

$(\sigma'_1 - \sigma'_3)_{ult}$ Ultimate deviatoric stress

$R_f$ Failure ratio defined as $R_f = \frac{(\sigma'_1 - \sigma'_3)_f}{(\sigma'_1 - \sigma'_3)_{ult}}$

$e_1$ and $e_2$ Arbitrary exponents

$n_e$ and $n_b$ Tangential modulus and bulk modulus exponent
<table>
<thead>
<tr>
<th>Symbol</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>( m_c ) and ( m_g )</td>
<td>Exponents controls the shape of the thermal dependence functions</td>
</tr>
<tr>
<td>( \varphi )</td>
<td>Friction angle</td>
</tr>
<tr>
<td>( \varphi_{\text{max}} )</td>
<td>Mobilized friction angle</td>
</tr>
<tr>
<td>( \varphi_{\text{cv}} )</td>
<td>Constant volume friction angle</td>
</tr>
<tr>
<td>( \Delta \varepsilon_v^e )</td>
<td>Plastic volume change</td>
</tr>
<tr>
<td>( \varphi^o )</td>
<td>Maximum friction angle</td>
</tr>
<tr>
<td>( \Delta \varphi )</td>
<td>Change of friction angle per log cycle of normalized minimum effective stress</td>
</tr>
<tr>
<td>( L_{\sigma} )</td>
<td>Stress level defined in FEM3D</td>
</tr>
<tr>
<td>( k_2 )</td>
<td>Current absolute permeability</td>
</tr>
<tr>
<td>( k_1 )</td>
<td>Original absolute permeability</td>
</tr>
<tr>
<td>( C_{nl} )</td>
<td>Proportional constant</td>
</tr>
<tr>
<td>( \varepsilon_v )</td>
<td>Volumetric strain</td>
</tr>
</tbody>
</table>
Chapter One: Introduction

1.1 Statement of the Problem

The negative impacts of top water and gas cap on Steam Assisted Gravity Drainage (SAGD) performance have been previously presented and discussed in the literature (Good et al., 1997; Nasr et al., 2000; Law et al., 2000). Both experimental and simulation approaches were conducted to determine SAGD steam chamber growth in the presence of a top thief zone. It was observed that the overlying top water and gas thief zones had detrimental effects on the SAGD recovery process since steam penetrates into these zones, which results in great heat loss (AEUB, 1998). Gas caps and top water zones occur extensively over the Surmont lease and are in pressure communication with the underlying bitumen interval. Piezometers and thermocouples data in observation wells shows an increase of the pressure and temperature in the top thief zone. In addition, geostatistical modeling workflow and thermal SAGD simulation construction for the Surmont pilot are summarized in this research, followed by computer assisted history-matching and optimization. The optimization strategies have been proposed in terms of the operating pressure and subcool control. Furthermore, Expanding Solvent Steam-Assisted Gravity Drainage (ES-SAGD) possibilities have been investigated using different solvent mixtures co-injected with steam. Through a sensitivity study, an optimal solvent mixture has been proposed for this case with a top thief zone.
1.2 Objectives of the Thesis

The objective of this research is to construct numerical flow simulation of a Surmont pilot using a well-defined 3D geostatistical model to determine the impact of the top thief zones on bitumen recovery. The focus of the study will be on three horizontal well pairs plus 15 vertical observation wells in the McMurray formation. The stochastic geostatistical model is to build a representation of the McMurray geology that honors the deposition structure, facies proportions, reservoir characteristics and petrophysical properties. Structural tops are interpreted from well logs and porosity-permeability relationships established from quantitative log analysis and core-log calibration. The facies-based log-derived porosity, permeability, shale volume and water saturation are populated into a grid block by Sequential Gaussian Simulation (SGS) in the petrophysical modeling process. Then a static model is upscaled to coarse simulation grids, and a submodel for each single well pair is extracted for the purpose of history match in STARS™
simulator. Reasonable history match of oil and water rates has been achieved by calibrating this static model with the field production data. The steam chamber pressure and temperature profiles from the numerical model has been conformed to the field data from the observation wells. Optimization of cumulative steam-oil ratios (cSOR) by varying the injection pressure and steam trap control with the top thief zones has been studied in great detail. An An Expanding Solvent Steam-Assisted Gravity Drainage (ES-SAGD) process has been investigated on a full field–based heterogeneous simulation model using an optimal solvent mixture. Finally, geomechanical effects on the ES-SAGD process are investigated through an iterative coupling approach.

1.3 Integrated Reservoir Modeling Work Flow

The summary of the workflow is:

- Quantitative log analysis and facies interpretation of Surmont pilot observation wells;
- 3D geological modeling including structural, facies, petrophysical modeling, and uncertainty analysis;
- Flow simulation of the SAGD process with top gas and water thief zones;
- Sensitivity studies to simulate the impact of the top gas pressure, thief zones extension and thickness on SAGD production behavior and recovery.
- Optimization of the cSOR and recovery factor for the SAGD process by varying the injection strategy and steam trap control.
- ES-SAGD numerical investigation
- Reservoir geomechanics coupled in the thermal simulation
Chapter Two: Literature Review

2.1 SAGD Process

Steam Assisted Gravity Drainage (SAGD) is an enhanced oil recovery technology for producing heavy crude oil and bitumen by steam injection. The concept of SAGD was initially proposed by Butler and his colleagues (Butler et al., 1981; Butler and Stephens, 1981). In this process, two horizontal wells are placed close to the bottom of a formation, with one above the other at a short vertical distance. Steam is continuously injected into the upper injection well with slightly above reservoir pressure. As the steam rises, moving both upward and sideward, it conducts its latent heat to the cold heavy oil and bitumen. As the reduction of the bitumen viscosity continues due to heat conduction, the heated oil together with the condensed steam drains into the lower production well. SAGD mechanisms include: steam condensate at interface, heated oil drain into the producer at bottom by the gravity flow and steam chamber rising (Figure 2-1).

Figure 2-1 - SAGD mechanisms and well configuration
2.2 Butler’s Theory

Butler’s theory on the prediction of heavy oil and bitumen is based on the heat conduction theory and Darcy’s equation. Butler’s equation is expressed as:

\[ Q_o = \sqrt{\frac{2\phi\Delta S_o \kappa g \alpha h_f}{mv_s}} \]

where:

- \( Q_o \): Oil production rate
- \( \kappa \): Permeability
- \( \alpha \): Reservoir thermal diffusivity
- \( \phi \): Porosity
- \( \Delta S_o \): Initial oil saturation-residual oil saturation
- \( h_f \): Net pay
- \( m \): Dimensionless (between 3-5, dependent on oil viscosity-temperature relationship)
- \( v_s \): Oil kinematic viscosity

The oil production in the SAGD process is sensitive to reservoir quality (porosity, permeability and bitumen thickness), reservoir rock thermal property and bitumen kinematic viscosity. Obviously, Butler’s theory provides the fundamental guidance in screening of a successful SAGD project. In the original SAGD concept proposed by Butler, heat transfer to cold oil ahead of the steam chamber is by conduction only and non-convection is involved. There are debates regarding the convection role in the SAGD process (Farouq-Ali, 1997; Ito and Suzuki, 1999; Edmunds, 1999).
2.2.1.1 Theory of Heat Conduction

Fourier’s Law states that conductive heat flux is proportional to a temperature gradient and thermal conductivity, which is expressed as follows:

\[ E = -K_h \frac{\partial T}{\partial x} \]  \hspace{1cm} 2.2

Where:

\( T \): Temperature
\( x \): Distance
\( E \): Heat flux
\( K_h \): Thermal conductivity

The energy balance equation in 3D is expressed as:

\[ \frac{\partial^2 T}{\partial x^2} + \frac{\partial^2 T}{\partial y^2} + \frac{\partial^2 T}{\partial z^2} = \frac{1}{\alpha} \frac{\partial T}{\partial t} \]  \hspace{1cm} 2.3

where:

\[ \alpha = \frac{K_h}{\rho c} \] (thermal diffusivity)

Heat flux into overburden is:

\[ \frac{\partial^3 T}{\partial x^3} = \frac{1}{\alpha} \frac{\partial T}{\partial t}, \quad \alpha = \frac{K_h}{\rho c} \]  \hspace{1cm} 2.4

\( T(0, t) = T_s, \quad T(\alpha, t) = T_R, \quad T(x, 0) = T_R \)

\[ T(x, t) = T_R + (T_s - T_R) \text{erfc} \left( \frac{x}{2\sqrt{\alpha t}} \right) \]  \hspace{1cm} 2.5

\[ q|_{t=0} = \frac{AK_h(T_s - T_R)}{\sqrt{\pi \alpha t}} \]  \hspace{1cm} 2.6
where:

- \( a \): Diffusivity
- \( \rho \): Density
- \( c \): Specific heat
- \( T_s \): Saturation temperature of steam
- \( T_R \): Reservoir temperature

### 2.2.1.2 Mathematical Models for Steam Flooding

There are three sets of the equations associated with the steam flooding theory shown here:

- Lauwerier’s Equation (Hot Water Flooding)
- Marx and Langenheim Steam Theory
- Mandl and Volek Theory

#### 2.2.1.2.1 Lauwerier’s Equation

Lauwerier’s model determines formation heating due to hot fluid injection. Temperature at any point between the injection fluid temperature and the initial reservoir temperature can be calculated using the following equation:

\[
T = T_R + (T_f - T_R) \text{erfc} \left[ \frac{x_D}{2\sqrt{t_D}} \right] \quad \text{for} \quad t_D > x_D
\]

\[
T = T_R \quad \text{for} \quad t_D \leq x_D
\]

\[
t_D = \frac{4K_{hub}M_{ob}t}{M_h^2 h_i^2}
\]

\[
x_D = \frac{4(24)K_{hub}M_{ob}A}{5.615M_s \rho_f c_f i_f h_i}
\]
where:

- $T_f$: Fluid temperature
- $T_R$: Reservoir temperature
- $A$: Area for linear flow
- $t_D$: Dimensionless time
- $x_D$: Dimensionless distance
- $M_s$: Formation heat capacity
- $V_s$: Steam zone volume
- $M_{ob}$: Heat capacity of overburden and underburden,
- $k_{ob}$: Thermal conductivity of overburden and underburden
- $\rho_f$: Density
- $c_f$: Specific heat of the injected fluid
- $i_f$: Hot fluid injection rate
- $h_i$: Net pay

### 2.2.1.2.2 Marx and Langenheim Theory

Marx and Langenheim’s (1959) model considers the injection of steam into a well at a constant rate and temperature. The simple assumption made in this model is that the temperature of the heated zone is uniform at the injected fluid temperature, while the regions outside the heated zone are at the initial reservoir temperature. Energy balance states that the total heat injected is the summation of the heat loss to the reservoir and heat to the fluids (oil and water in-situ).
The Marx-Langenheim model assumptions are:

- Constant injection rate
- No pressure drop in steam zone
- No gravity effects
- Homogeneous sands and over/underburdens
- Temperature at steam front (inside) is steam temperature
- Temperature at reservoir side of steam front is reservoir temperature
- No hot water flow ahead of steam front

The heat balance equation is:

\[ Q_i = Q_{ob} + Q_s \]  \hspace{1cm} (2.8)

\[ Q_i = i_{st} \left[ h_w + f_{st} L_v - c_w (T_R - 32) \right] \] \hspace{1cm} (2.9)

\[ Q_s = M_s (T_s - T_R) \frac{dV_s}{dt} \] \hspace{1cm} (2.10)

where:

- \( Q_i \): Heat injection rate
- \( Q_{ob} \): Heat loss rate to the overburden and underburden
- \( Q_s \): Heating rate of the rock and fluids to temperature \( T_s \)
- \( i_{st} \): Steam injection rate
- \( h_w \): Enthalpy of saturated water
- \( f_{st} \): Steam quality
- \( L_v \): Latent heat of vaporization
$c_w$: Specific heat of water

$T_s$: Saturation temperature of steam

$T_R$: Reservoir temperature

$M_s$: Formation heat capacity

$V_s$: Bulk volume of steam zone

The Marx-Langenheim model solution of $Q_s = M_s(T_s - T_R) \frac{dV_s}{dt}$ equation gives:

\[ V_s(t) = \frac{QM_s h_i^2}{4K_{hob} M_{ob}} \left[ e^{\frac{d}{t_D}} \text{erfc} \sqrt{t_D} + 2 \sqrt{\frac{t_D}{\pi}} - 1 \right] \]  \hspace{1cm} (2.11)

\[ t_D = \frac{4K_{hob} M_{ob} t}{M_s^2 h_i^2} \]

\[ Q_{loss} = 1 - \frac{F_1}{t_D}, \quad F_1 = \left[ e^{\frac{d}{t_D}} \text{erfc} \sqrt{t_D} + 2 \sqrt{\frac{t_D}{\pi}} - 1 \right] \]  \hspace{1cm} (2.12)

where:

\[ \frac{dF_1}{dt_D} = e^{\frac{d}{t_D}} \text{erfc} \sqrt{t_D} = F_2 \]

2.2.1.2.3 Mandl and Volek Theory

Mandl and Volek (1967) developed a more rigorous heating model by introducing the concept of the critical time, taking into account the hot water transport ahead of the condensing steam front. The critical time defines the boundary of changing from conduction heat flow to purely conductive dominated flow.
\[ V_s(t) = \frac{QM_{sh}h^2_i}{4K_{shb}M_{ob}(T_s-T_R)} F_1, \quad t \leq t_c \]  \hspace{1cm} 2.13

\[ V_s(t) = \frac{QM_{sh}h^2_i}{4K_{shb}M_{ob}(T_s-T_R)} F_3, \quad t > t_c \]  \hspace{1cm} 2.14

\[ t_{Dc} = \frac{4K_{shb}M_{ob}t_c}{M_s^2h^2_i} \]

\[ F_3 = \left[ e^{D} \text{erfc}\sqrt{t_D} + 2\sqrt{\frac{t_D}{\pi} - 1} - \sqrt{\frac{t_D-t_{Dc}}{\pi}} \left[ 1 + \frac{f_wL_v}{c_w(T_s-T_R)} \right]^{-1} \left( \frac{t_D-t_{Dc}}{3} \right) \right] e^{D} \text{erfc}\sqrt{\frac{t_D-t_{Dc}}{3\pi t_D}} \]

where:

\( F_1 \): Function of the dimensionless time

\( F_3 \): Function of the dimensionless time

\( \text{erfc}(x) \): Error function of x

\( t_c \): Critical time

\( t_{Dc} \): Dimensionless critical time

2.3 Basic description of STARS

2.3.1 Thermal Simulator STARS

STARS is a three-phase multi-component thermal and steam additive simulator developed by the CMG Ltd. to simulate steam flood, steam cycling, steam-with-additives, and dry and wet combustion, along with many types of chemical additive processes, using a wide range of grid and porosity models in both field and laboratory scales.
2.3.2 Data Structure of STARS Simulation Model

STARS has the flexible grid systems such as Cartesian, cylindrical, or variable depth/variable thickness, with two-dimensional and three-dimensional configurations. The model is setup using the keyword input system including the following sections:

- **Input/Output Control**: Define parameters that control the simulator's input and output activities.
- **Reservoir Description**: This section contains data describing the basic reservoir definition and the simulation grid used to represent it.
- **Other Reservoir Properties**: This section contains data describing other reservoir properties. These data can be classified into the following groups:
  1. Formation Compressibility
  2. Reservoir Rock Thermal Properties
  3. Overburden Heat Loss Options
- **Component Properties**: Indicate the number of each type of component in preparation for fluid data inputs such as density, viscosity, critical properties and K-value correlations.
- **Rock-fluid Data**: Define relative permeabilities, capillary pressures, and component adsorption, diffusion and dispersion.
- **Initial Conditions**: Specify initial reservoir pressures and temperatures with appropriate equilibrium option.
• Numerical Methods Control: Define parameters that control the simulator's numerical activities such as time stepping, iterative solution of non-linear flow equations, and the solution of resulting system of linear equations.

• Geomechanical Model: Enable the coupled reservoir geomechanics option in modeling the interactions between the flow model and stress model (porosity and permeability are altered due to the changing of the stress and strain).

• Well and Recurrent Data: The section contains data and specifications which define the well constraints and time-dependent information using keywords.
Chapter Three: 3D Geostatistical Model

3.1 Introduction
The Surmont project is located approximately 60 kilometres southeast of Fort McMurray, Alberta, in the Athabasca oil sands region. Surmont is operated by ConocoPhillips Canada and is a 50/50 joint-venture with Total E&P Canada. The Surmont Pilot started in 1997 with two horizontal well pairs (350m). An additional 700m well pair was drilled in 2000. The project was designed with 1,500 bbl/d oil capacity, 7,500 bbl/d inlet capacity and 3,750 bbl/d steam generation capacity (additional steam generation added in 2003). The pilot project consists of three horizontal SAGD well pairs drilled in a northeast to southwest direction located in LSD 14-24-83-7 W4M as follows:

- Well pair A: center well pair 350 m horizontal section.
- Well pair B: northern well pair 350 m horizontal section.
- Well pair C: southern well pair 700 m horizontal section.

3.2 Geology
The McMurray formation in Surmont, subdivided into lower, middle and upper parts, is 40-60 meters in thickness and consists of mostly uncemented, very fine to medium-grained quartz arenite, interbedded with shale. Bitumen is mainly concentrated in the lower and middle parts with fluvial and estuarine channel sand. The lower part is a fluvial channel with coarse to fine grain, poorly sorted channel sand, with water saturated in many areas. The middle and upper members are the best reservoirs with bitumen intervals. Bitumen deposits in an estuarine channels environment with fine grain sand. The upper part is a mixed tidal flat environment
composed of silty sand and shale interbeds (AEUB, 1998) and contains the gas cap and top water zone, which are defined as the thief zones to the SAGD process.

Figure 3-1 - Well pairs and 15 observation wells in the pilot project
Three members were described inside the McMurray Formation:

- **Lower Member**: conglomeratic sandstone, present only in depressions formed in the underlying Devonian limestone.
- **Middle Member**: massive well sorted, fine grained oil saturated sand in the base, with inclined beds of thick ripped sandstone and thin shaley siltstone partings in the top.
- **Upper Member**: horizontal, argillaceous very fine grained sandstone with oil saturation

### 3.2.1 Geological modeling

The objective of the geostatistical modeling was to build a geological representation of the McMurray formation that honors the reservoir heterogeneity in a grid scale. Structural tops are interpreted from the well logs, and seven structural surfaces are built based on the well tops, from which two horizons, McMurray and BeverHills formations are generated. These two horizons contain the interest interval of the McMurray formation. A geomodel grid consisting of $24 \times 25 \times 80$ blocks is constructed for the geostatistical analysis. The block size is $50 \times 25 \times 1$ m in the $i \times j \times k$ directions, respectively, with 48,000 cells in total. The porosity, permeability, shale volume, and water saturation characteristics are derived from the quantitative log analysis; the vertical and lateral facies distributions are determined from cores and log analysis. A porosity-permeability relationship is established using the correlation based on the 15 observation wells core data and digital LAS well logs. Then static properties were populated into a grid block by SGS simulation, and the grid was up-scaled to fit the coarse simulation. Five lithofacies obtained from the core study are: Sand, Sand IHS, Mud IHS, Mudstone Breccia, and Mudstone (ERCB, 2009). Both top and bottom water are present in the Surmont pilot area. The main spectrum of $S_w$ in the pay interval at the middle McMurray formation is about 20%,
whereas the top layer is much higher up to 85%. The continuous bitumen thickness is above 40 meters, which is ideal for the SAGD process.

3.2.2 Structural modeling

The McMurray 3D structural model is built based on the well log derived tops and surface, which is the major constraint in making the horizons, layering and zoning process. The size of the model is about 1,200 m × 700 m covering the pilot project area. A single zone of the McMurray formation is modeled with 48,000 blocks. Figure 3-2 shows the cross section of four observation wells along SAGD pair C.

![Figure 3-2](image)

Figure 3-2 - Cross section of 4 observations along well pair C showing the vertical facies and properties distribution.
3.2.3 Facies modeling

The McMurray formation is divided into five lithofacies as shown in Figure 3-3:

- Sand
- Sand IHS
- Mud IHS
- Mudstone
- Breccia

Facies modeling is populating core-log calibrated electro-facies into a 3D geological grid by using Sequential Indicator Simulation and the major processes include facies log upscaling, data analysis, stochastically modeling, and quality control. The data analysis is an important step where a variogram model was generated. The variogram model is used to determine the spatial variation in three directions, including vertical, major and minor directions due to anisotropy. The principal artificial neural network is trained in the cored well, which has the predefined facies interpretation based on the lithology and well logs. Key well logs GR, NPHI, and RHOB are used as the input in the supervised training process. Once the training model is established, the facies log was populated into the uncored interval. In this study, the variograms model for each facies is generated and imported into the facies modeling process and multiple realizations are run in order to access the uncertainty of the facies.
Figure 3-3 - Facies distribution in the 3D model.

3.2.4 Petrophysical modeling

Property modeling uses SGS (Sequential Gaussian Simulation) to populate properties stochastically into grid cells. Several major steps include the scaling-up of well logs, data analysis and transformations, variogram modeling and uncertainty analysis. The data analysis process helps define data transformation and generate variograms. Variograms are prepared as input for facies and petrophysical modeling. Properties are modeled for each facies and multiple representations were obtained (Figure 3-4). In addition, a collocated co-kriging algorithm is used in simulation, taking porosity as the secondary variable. The arithmetic mean is used for the
volume based porosity and water saturation; the harmonic mean is used for permeability since it is sensitive to the low values such as mudstone acting as the steam baffle.

A hundred realizations are run to assess the uncertainty due to structural, facies, and properties distribution with 50% probability (P50) of original bitumen in-place (OBIP) at 9.43821E+6 m$^3$. The static model is further downscaled to 50×1×1m for SAGD simulation by repopulating the properties in the grid blocks. This is to keep the block size at 1m x 1m in the cross-section of the steam chamber. The grid size in the $i$-direction parallel to the horizontal well direction is kept at 50 meters because of the manageable computational efficiency. Three realizations (P10, P50 and P90) have been simulated in STARS and the differences of oil production are minor. Eventually, these differences will be taken over in the history matching process by changing the permeability multipliers locally and shifting the relative permeability curve. Therefore, realization #10 (P50) with a moderate oil rate has been selected for the following study.
Figure 3-4 - Properties distribution in 3D grid. A: Facies distribution; B: Permeability; C: Water saturation; D: Porosity.

3.3 Conclusion and Discussion

- Geostatistical modeling is the most effective tool in capturing the reservoir heterogeneity and analyzing the uncertainty.

- Modeling the steam baffle mudstones and mud breccias is critical in the facies modeling process.

- Characterization of the top water zone has a great impact on the dynamical simulation results.
Chapter Four: Reservoir Simulation Model

4.1 Simulation Model Set up for SAGD

A three well pairs’ model with a detailed heterogeneous geological description obtained from the geostatistical modeling package Petrel is exported directly into STARS (Figure 4-1). A submodel with pair A subtracted from the three well pairs case has $102 \times 6 \times 40$ grids with increment of $1 \text{ m} \times 1 \text{ m}$ in the $i$ and $k$ increments total 24,480 grid blocks. In addition, a 2D cross-sectional model with three well pairs is subtracted for the sensitivity study. Unconfined top gas and top water are simulated in both the 2D cross-sectional model and the 3D model.

![Permeability](image)

Figure 4-1 - SAGD well pairs configuration in the numerical simulation model

The oil saturation distribution shows the reservoir with relatively high oil saturation located in the middle of the reservoir with approximately 40 m thick. The permeability distribution also shows that a high level is in the middle part of the reservoir. The production well is located at the
bottom of the reservoir and the injection well is 5 m above the production well. The high water saturation region is at the top of the reservoir with the top gas zone (4m) above. The porosity and permeability are both low in this region. It is a three-phase model with bitumen, water and CH₄ and the solution gas plays an important role in bitumen recovery. The gas saturation in the top gas cap is set at 0.85 with a thickness of 4 meters. The overlying top water is 10 meters thick and $S_w$ is imported from the static model. Three well pairs A, B and C were initialized at reservoir pressure of 1,650 kPa, which corresponds to the top gas pressure of 1,050 kPa. The fluid, rock and thermal properties used in the model are listed in Table 4-1 (Gates et al., 2005).

**Table 4-1 - Fluid and thermal rock properties**

<table>
<thead>
<tr>
<th>Property</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Formation temperature ( °C)</td>
<td>10</td>
</tr>
<tr>
<td>Initial pressure (kPa)</td>
<td>1650</td>
</tr>
<tr>
<td>Rock heat capacity (KJ/m³ °C)</td>
<td>2350</td>
</tr>
<tr>
<td>Rock thermal conductivity (KJ/m d °C)</td>
<td>125</td>
</tr>
<tr>
<td>Overburden/underburden heat capacity (KJ/m³ °C)</td>
<td>1169</td>
</tr>
<tr>
<td>Overburden/underburden thermal conductivity (KJ/m d °C)</td>
<td>74.9</td>
</tr>
<tr>
<td>Bitumen thermal conductivity (KJ/m d °C)</td>
<td>11.5</td>
</tr>
<tr>
<td>Bitumen viscosity correlation $\ln \ln \mu(cp) = A + B \ln T(K)$</td>
<td>$A=22.8515$  $B=-3.5784$</td>
</tr>
<tr>
<td>$k$ value correlation $k = \frac{k_{v1}}{P} e^{K_{v1} - K_{v2}}$</td>
<td>$k_{v1} = 5.4547e^5$ kPa  $k_{v2} = -879.84 ^\circ$C  $k_{v3} = -265.99 ^\circ$C</td>
</tr>
</tbody>
</table>
The SAGD circulation period is three months and six line heaters are placed for each well pair using HTWELL keyword. Three temporary production wells were placed for each well pair in the location of the injection wells to relieve pressure buildup due to the thermal expansion. The production well set at steam trap control is set at 15°C. The injection rate of the injectors is set at the field injection rate for history match. Steam injected is at quality of 0.9 and temperature is 212°C. Two gas producers are inserted in the gas cap with BHP at 1,050 kPa to maintain the gas cap pressure.

4.1.1 Viscosity vs. Temperature Function

\[
\ln \ln \mu (cp) = A + B \ln T (K)
\]

Where:

\[ A = 22.8515 \]

\[ B = -3.5784 \]

4.1.2 K-Value Correlation

As a function of \( P \) and \( T \), the \( k \) value is

\[
k = \left( \frac{k_{v1}}{P} + k_{v2}P + k_{v3} \right) \frac{k_{v4}}{T - k_{v5}}
\]

where \( T \) is temperature and \( P \) is the gas phase pressure. \( k_{v1}, k_{v2}, k_{v3}, k_{v4} \) and \( k_{v5} \) correspond to the units of \( P \) and \( T \). This expression for \( k \) accounts for curvature of the vapor pressure curve with pressure.

\( k_{v1} \): First coefficient in the correlation for gas-liquid \( k \) value (kPa | psi).
$k_{v2}$: Second coefficient in the correlation for gas-liquid $k$ value (1/kPa | 1/psi).

$k_{v3}$: Third coefficient in the correlation for gas-liquid $k$ value.

$k_{v4}$: Fourth coefficient in the correlation for gas-liquid $k$ value (C | F). This coefficient has the unit of temperature difference. It has the same value for temperature scales C and K, and has the same value for temperature scales F and R.

$k_{v5}$: Fifth coefficient in the correlation for gas-liquid $k$ value (C | F). This coefficient has the unit of temperature, and is different for each temperature scale. Often this coefficient is quoted in other sources in absolute degrees K or R, even though all other temperatures are quoted in °C or °F. Here, this coefficient is quoted in the same unit as all other temperatures so it may be necessary to convert it from absolute to C or F.

In the data file for the Surmont SAGD, $k$-values are defined as follows:

$k_{v1} = 5.4547e^5$ kPa

$k_{v2} = 0$

$k_{v3} = 0$

$k_{v4} = -879.84$ °C

$k_{v5} = -265.99$ °C
4.1.3 Relative Permeability Curve

The relative permeability interpolation scheme provides the user with a flexible tool for representing surfactant effects on relative permeability. Consider a single rock type with conventional water/oil relative permeability curves corresponding to high interfacial tension. As surfactant is added to the system, residual saturations can decrease and the relative wettability of the phases can change. Ultimately, high surfactant concentrations and the resulting ultra-low interfacial tension values lower the residual saturations and straighten the relative permeability curves.

Figure 4-2 - Water oil relative permeability curves

4.1.4 Computer-Assisted History Matching

The Surmont three well pairs model was initialized with steam injection beginning on August 1st, 1997 and ending on the June 1st, 2008. The history matching process involves adjusting pre-heating, well constrains, steam trap control, and shale layer sensitivity. The base case model was run on a machine with 3.0GHZ CPU, quad-core, and 4G RAM taking about 10 hours. The base
case with three months pre-heating and steam trap 15°C gives fairly good results compared to the field production data. Differences between calculated and measured oil cumulative production are minor. Fine-tuning of history matching was achieved in the well pair A using the computer-assisted automatically history matching method. The investigation on each parameter and its impact on the simulation results are discussed in great detail.

The traditional history matching is an iterative procedure in which reservoir parameters are tuned manually until the actual field performance is matched by the simulation model. This process highly depends on reservoir engineers’ experience and is very time-consuming since only one result is obtained after each run with a certain input. Even though a satisfactory match may be reached by the trail-and-error, a single best matched case usually limits our scope on understanding of the model since other combinations of reservoir parameters which may provide better results are ignored. In this study, we apply computer-assisted history matching, optimization, and an uncertainty assessment tool in our model. It is a semi-automatic process in which various results are calculated, compared and analyzed based on the selected combinations of parameters. The methodology includes combinatorial optimization, experimental design, evolutionary algorithms, uncertainty quantification and distributed computing (Yang et al., 2007).

4.1.5 Base Case Model

Since the simulation time for the full-field Surmont flow model with three well pairs is about 10 hours, to illustrate the procedure which may require hundreds or even thousands of runs, we need a relatively simple model that can be handled within a reasonable time frame. Here, we focus on the history matching of a cropped model consisting of a single well pair A (106_05-24-083-
7w4_0 and 107-05_24-083-07w4_0) and exactly the same well trajectories and geology in the production period from August 1st, 1997 to Jun 1st, 2008. The run time of the single well pair base case is reduced to two hours on the same computer. As shown in Figure 4-3, the comparison of the base case result and production data shows that cumulative oil curves are matched pretty well; however, the cumulative water curve is underestimated. We attempt to improve the model by matching both cumulative oil (Cum-Oil) and cumulative water (Cum-Water). Thus the objective function to be minimized is the relative difference between the production data and simulation results.

4.1.6 Parameterization

A large number of parameters are involved in a reservoir model and varying any of them may influence the performance of the model. However, it is impossible and unpractical to consider all these parameters due to time requirement and computational power. We thus have to limit the adjustable parameters by our experience in this study as follows:

- The $i$-direction permeability multiplier (MOD_I).
- The $j$-direction permeability multiplier (MOD_J).
- The vertical and horizontal permeability ratio ($K_v/K_h$).
- The relative permeability to water at $S_w = 1 - Soirw$ ($K_{RWIRO}$).
- The relative permeability to oil at the connate water and zero gas saturation $S_w = 1 - Soirw$ ($K_{ROCW}$).
- The water-oil relative permeability table SWT based on the different power law exponent smoothing.
For each chosen parameter, a set of discrete values are selected to be its candidates in the matching process. These discrete values are based on the reservoir geology and experience as well. The selection of parameters and their corresponding discrete values play a crucial role in the success of computer-assisted history matching.

The parameter space can be further reduced by first using a sensitivity analysis (SA) tool. SA helps us determine how each parameter affects the result with only a small number of runs. Here, a full factorial sampling method is selected, and the SA results allow us to dismiss the parameters MOD_J and Kv/Kh since they have relatively little effects on the simulation results comparing with others. Not only does it give us a quantitative description of the parameters’ effectiveness, but also it reduces the dimensions of the searching space in history matching from six to four, by which computational time is greatly decreased.

4.2 History matching and Results

Four parameters and their corresponding discrete values used for history matching are listed in Table 4-2. By the multiplication principle, there are totally $3 \times 3 \times 3 \times 6 = 162$ combinations of parameters, and, therefore, 162 runs are required for finding the best match. However, instead of iteratively calculating all the results, the CMOST history matching tool intellectually searches for the global minimum of the objective function in the discrete parameter space using the methodology mentioned above and eliminates undesirable parameters which may lead to large errors during the process. Instead of 162 runs, totally 105 simulation runs are performed and the history match error ranges from 4.6801% to 19.557%. Among the 105 runs, 49 cases converge regularly while the other 56 ones do not. The six runs that give us the global history match error less than 7% are run#24, #40, #42, #43, #84, and #85 with relative match errors of 6.8368%,

4.6801%, 6.4005%, 5.0475%, 6.2223%, and 6.4079%, respectively. The total run time for the history matching process is about six and a half days. The discrete values used in these six best matches are listed in Table 4-3.

In Fig. 4-4, CumOil and CumWater of the historical data, base case, and CMOST results are plotted. The brown curves stand for the best and the light blue ones represent undesirable results. This illustration gives us a straightforward impression on how the model is improved. Table 4-3 shows the best 6 matches in this study with a minimum history match error. Fig. 4-3 plots and compares the best match result, base case results and historical production data. As illustrated in this figure, in the production period between August 1st, 1997 and June 1st, 2008, cumulative oil and cumulative water are increased and the value and curve trends are nicely developed to fit the production data. Substantial improvements are achieved in history matching by reducing the relative history error from 9.2% to 4.6801%.
Table 4-2 - Parameters used in history matching

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Discrete Values</th>
</tr>
</thead>
<tbody>
<tr>
<td>MOD_I</td>
<td>0.7, 0.8, 0.9</td>
</tr>
<tr>
<td>KRWIRO</td>
<td>0.1, 0.2, 0.3</td>
</tr>
<tr>
<td>KROCW</td>
<td>0.8, 0.9, 0.6</td>
</tr>
<tr>
<td>SWT</td>
<td>$k_{rw3_kro1.5}$, $k_{rw3_kro2}$, $k_{rw3_kro2.5}$, $k_{rw2.5_kro1.5}$, $k_{rw2.5_kro2}$, $k_{rw2.5_kro2.5}$</td>
</tr>
</tbody>
</table>

*krw3_kro1.5 means that krw is smoothed by the power law exponent of 3 and kro is smoothed by the power law exponent of 1.5

Table 4-3 - Parameter discrete value for 6 best matches

<table>
<thead>
<tr>
<th>Run #</th>
<th>MOD_I</th>
<th>KRWIRO</th>
<th>KROCW</th>
<th>SWT</th>
<th>Relative error%</th>
</tr>
</thead>
<tbody>
<tr>
<td>24</td>
<td>0.7</td>
<td>0.2</td>
<td>0.9</td>
<td>$k_{rw3_kro1.5}$</td>
<td>6.8368</td>
</tr>
<tr>
<td>40</td>
<td>0.9</td>
<td>0.2</td>
<td>0.9</td>
<td>$k_{rw3_kro2.5}$</td>
<td>4.6801</td>
</tr>
<tr>
<td>42</td>
<td>0.8</td>
<td>0.1</td>
<td>0.8</td>
<td>$k_{rw2.5_kro2}$</td>
<td>6.4005</td>
</tr>
<tr>
<td>43</td>
<td>0.8</td>
<td>0.2</td>
<td>1</td>
<td>$k_{rw3_kro2}$</td>
<td>5.0475</td>
</tr>
<tr>
<td>84</td>
<td>0.9</td>
<td>0.2</td>
<td>0.8</td>
<td>$k_{rw3_kro2.5}$</td>
<td>6.2223</td>
</tr>
<tr>
<td>85</td>
<td>0.9</td>
<td>0.1</td>
<td>0.8</td>
<td>$k_{rw2.5_kro2.5}$</td>
<td>6.4079</td>
</tr>
</tbody>
</table>
Figure 4-3 - Comparison of base case and the best match results

Figure 4-4 - Cumulative Oil and Cumulative Water history matching results
4.3 Sensitivity Study

The objective of Sensitivity analysis is to determine the overall variation of simulation results under different parameter values and which parameters have the greatest effect on simulation results. The base case model for the sensitivity run is the history matched single well pair 3D model with both top gas and top water. In addition, the 2D cross-sectional three well pairs’ model is implemented in the sensitivity study to evaluate the chamber interactions. The injection rate is set according to the field rate and the subcool setting for the producer is 5°C for the base case. In the 3D full field model, the steam chamber approaches the top water in 2008, where the chamber pressure is 1,235 kPa and the top water zone pressure is 1,120 kPa. Simulation shows that top water collapsed into the chamber causing great heat loss. The results are shown in Figure 4-5.

Figure 4-5 - Steam chamber conformance from 2005 to 2012 of single pair A 3D model
The real situation can be more complex depending on the size of the extended gas cap, the size of the water body, and shale layer distribution. Many simulation runs show that changing the injection pressure and varying the subcool can cause the breakthrough occurring more quickly. Oil has moved into the top water zone in a fingering fashion and water has been pushed into the top gas zone (Law et al., 2003). In some cases, breakthrough happens in the early production and water collapses into the steam chamber. Through the sensitivity study, the optimal case with higher cumulative oil and better cSOR will be addressed.

4.3.1 Gas Cap Pressure Sensitivity of 3D Model

Sensitivity runs are performed on the single pair 3D model with a top gas zone pressure of 600 kPa. The objective is to observe the depleted gas zone and its effect on bitumen recovery. The extended top gas and top water zones are simulated. Six horizontal gas producers are introduced in the top gas zone with an initial BHP of 500 kPa for a short production and then switched to 1,050 kPa. The pressure drop is kept within the top thief zone without affecting the initial reservoir pressure. As the system equilibrates after the gas producers are shut in, the top gas zone stabilizes at 600 kPa before the SAGD starts. The depleted gas zone situation is achieved. Simulation runs were compared to the base with a thief zone pressure of 1,050 kPa and the result is shown in Figure 4-6. Decreasing the top gas pressure results in lower oil production and higher cSOR.
Figure 4-6 - Gas cap sensitivity analysis simulation results shows that the depleted gas cap has the worst production and higher cSOR

4.3.2 Thief Zones Sensitivity of 3D Model

Thief zone sensitivity runs are carried out with four cases by varying the top gas and water zones. Case A has only top gas overlying the bitumen, no top water in presence; Case B has only top water overlying the bitumen without a top gas zone; Case C has shale and mudstone sealing the bitumen, without a thief zone in presence; Case D has a top water zone replaced by the gas cap. Obviously, Case C without any thief zone yields the best result. Case D with a thicker gas cap has the lowest oil production and much higher cSOR. Both Cases B and C are better than the base case; however, Case A with only top gas is worse than the base case having both top water and top gas. The possibility is the gas blanket venting into the top gas thief zone, accelerating the steam rising rate upward (Edmund, 2005), which causes the steam chamber positioning higher than the case with top water, breaking through into the thief zone earlier. The comparison of the steam chamber growth is shown in Figure 4-7.
4.3.3 Steam Injection Pressure Sensitivity of 2D 3 Well Pairs Model

Sensitivity runs are given by varying the injection pressure at 1,000 kPa, 1,500 kPa and 3,000 kPa in order to observe its effect on steam chamber conformance. A lower injection pressure is attractive because the steam has greater latent heat also with lower cSOR compared to a higher injection pressure, especially for the SAGD process with top water and gas thief zones. The steam chamber for Pair A and Pair B developed much slowly because of the low injection pressure of 1,500 kPa at the SAGD start-up. The advantages of lower injection pressure show up
and the steam chamber continues growing under the top water zone after year 2004. The cumulative oil curve climbs up with relative constant cSOR under 3.0 in the early production.

In contrast, the constant 3,000 kPa injection leads to the earlier breakthrough for all three well pairs. The steam chamber penetrates into the top thief zones more quickly causing water to collapse into the chamber. As a result, a higher steam injection rate causes cSOR at 3,000 kPa to double. Eventually, the constant injection pressure 1,500 kPa does not prevent the breakthrough for both pair A and pair B. Steam conformance mainly depends on the reservoir heterogeneity as the comparison of three well pairs shows in Figure 4-8.

Pair B (right) located in the relative high permeability zone and with 1,000 kPa injection pressure yields the lowest cSOR and highest cumulative oil rate. Pair C (left) is located in a relative lower permeability zones compared to Pair B so steam chamber was not able to develop under the 1,500 kPa injection pressure until 2008, while the 3,000 kPa injection pressures gives a good start up. These lead to high injection pressure at start up and low pressure when approaching the thief zone, which will be discussed for each well pair later in this thesis.
Figure 4-8 - Case run with constant injection pressure 1,000 kPa. Permeability distribution (a), chamber conformance (b), water saturation distribution (c), and reservoir pressure (d) from top left to bottom right. Pair B (right), Pair A (middle), Pair C (left). In this case, pair C was not able to start due to the low injection pressure at 1,000 kPa

4.3.4 Sensitivity of Mudstone Layer in three Well Pairs Model

Mudstone acts as the steam baffle in Surmont. Sensitivity runs are performed with mudstone and mud breccias layers with 50mD and 1 meter thick located in the top of the well pairs. In the first four years production, the cumulative oil rate is slightly lower than the base case without steam baffle, but at 2008, the cumulative oil rate is higher than the base case and cSOR is lower. The mudstone baffle prevents the steam penetrating into the top water zone, causing the steam chamber growth more laterally. It can be further integrated into the history matching process for fine tuning the oil rate and reducing the uncertainty of the mud breccias distribution from the static model.
4.3.5 Steam Trap Control Sensitivity of 2D and 3D Models

The steam trap control is used to prevent the steam production from the producer in SAGD operations. It indicates the difference between the steam saturation temperature which corresponds to the well bottomhole pressure and the temperature of the produced water. The higher the subcool values, the higher the liquid level accumulated at the production well and the lower the oil production rate. If the liquid level is too low, there will be a risk of producing the steam. Therefore, it needs be controlled in a certain inter-well level to achieve optimal performance. In general, subcool lies between 15-40°C. Edmund (1998) stated that a 2D model cannot capture the effect of the steam trap control on SAGD performance. Gates et al. (2005) demonstrated that interval well subcool varies along the wellbore and it failed in some intervals. Two studies are run using the 2D and 3D models to test the subcool effect. Field data (Surmont report 2004) showed that pair A subcool remain between 25-35°C; pair B remained between 20-25°C; pair C was quite high at 50°C upon start up and dropped to between 10-15°C. Sensitivity runs are carried out with steam trap control at 5, 15, 30, 40°C, respectively. The subcools at 5 and 15 °C are identical with the best cSOR and oil rate. 40°C is the worst case. Simulations run on the 2D cross-sectional model with three well pairs and the impact on SAGD performance for all three well pairs share the common characters: the lower the steam trap control, the higher the bitumen production and lower cSOR. Sensitivity is also performed in the 3D single well pair 1,500 kPa injection pressure control, which yields that 15 °C is the optimal case for pair A.

4.4 Optimization

Optimization of SAGD helps to determine the most economical operating conditions. Edmunds and Chhina (2001) concluded that the economic efficiency of the SAGD process was controlled
by the costs of generating steam, water treatment and recycling. Often, the generation of steam is the most expensive activities in SAGD operation. Therefore, the thermal efficiency measured by the cumulative injected steam to the produced oil ratio (cSOR) is a key factor in determining whether the project is commercially successful or not. Lower cSOR usually stands for a more economic level since less natural gas is burned per unit volume of produced oil. In this sense, cSOR is selected as an economic objective function to be minimized and it is a monotonic function of operation pressure (Edmunds and Chhina, 2001). However, the strategy that can achieve both low cSOR and high production rate still needs to be studied.

SAGD optimization has been studied extensively in the literature. Edmunds (1998) presented an effective subcool setting for 2D and 3D models through the numerical simulation of an Athabasca reservoir. They pointed out that SAGD success was determined by cSOR rather than the oil production rate. Ito and Suzuki (1999) indicated that optimal subcool for the McMurray formation in Hangingstone was between 35°C and 40°C. Kisman and Yeung (1995) concluded that the operating pressure had a larger effect on the CDOR; the lower the injection pressure the lower cSOR. Gates and Chakrabarty (2005) developed a GA method to achieve the optimal operating pressure. Their results suggested that the higher injection pressure at SAGD start-up follows the lower injection after the contact. Law et al. (2003) evaluated the SAGD performance with top thief zones and found that heat loss in the top gas case was less compared to the top water case. Yang et al. (2009) presented optimization and uncertainty assessment strategies of SAGD operations using CMG’s DECE (Designed Exploration and Controlled Evolution) optimization method. They improved the performance of a SAGD project with two planned well
pairs and eight existing primary production wells by adjusting steam injection rates and producing liquid withdrawal rates during different operating periods.

In this study, these methodologies and ideas are tested in the full field model. Optimization in this thesis mainly focuses on the steam trap control and operating strategy based on the sensitivity runs. A careful design of the operating strategy is critical for SAGD with top thief zones. Improper operation would lead to the early breakthrough and cause significant reduction in recovery. The pair A chamber is stabilized and growing laterally, while for other two pairs steam rises directly into the top water zone. By finding the optimal injection strategy and steam trap control for each well pair, early breakthrough will be eliminated. The 2D cross-sectional case is used in the optimization of three well pairs. The advantage is to observe the interaction between the well pairs, and also the run time is significantly reduced to about two hours.

4.4.1 Injection Pressure Optimization

The optimal operating strategies for all the cases reviewed have a common methodology of maintaining a high steam chamber pressure early in the SAGD process (Gates et al., 2005). The higher the steam chamber pressures, the faster the chamber growth and the higher the chamber temperatures. Upon breakthrough, the operating pressure of the steam chamber is slightly higher than that of the thief zone, which will balance heat losses into the thief zone against top water drainage into the steam chamber.

The optimal injection pressure strategy is tested on three well pairs and the results show that the injection pressure strategy varies for each well pair. Pair C injection pressure starts at 3,500 kPa and is step-wise reduced to 2,000 kPa, 1,500 kPa, 1,000 kPa, and 500 kPa. Pair A and Pair B injection pressures start at 2,500 kPa, and are step-wise reduced into 1,500 kPa and 1,000 kPa. A
higher injection pressure of 3,500 kPa at start up causes the earlier steam breakthrough into the top water. In addition, as the steam chamber approaches the top water at year 2006, three injection pressures 1,500 kPa, 1,000 kPa, and 500 kPa are tested. The pressure of 1,000 kPa yields the best result, which demonstrates the 1,000 kPa injection pressure is the optimal strategy at later time for all three well pairs with the lower cSOR at 2.0 and moderate oil production (Figure 4-9).

Figure 4-9 - Optimization result of 3 well pairs showing the steam chamber conformance

Limited by computation power and time frame, the full-field Surmont flow model with three well pairs which takes about 10 hours for a single simulation run was not used here. Instead, a cropped two-dimensional model with well pair C (I/P: 1AB/1AA-04-24-83-7 W4M), geological heterogeneities, and top thief zones in the production period from January 1st, 2001 to July 1st,
2008 is employed to illustrate the workflow and evaluate an optimization procedure. The total number of grid blocks in the model is \(1 \times 93 \times 40 = 3,720\). Previous studies on SAGD optimization show that high injection pressure is preferred in early stage before the steam chamber contacts the overburden and low pressure is used afterward. A base case with manually selected pressures from 2,500 kPa to 1,000 kPa in eight consecutive time periods was run for comparison purpose (Table 4-4).

Table 4-4 - Injection pressure strategy used in the base case model

<table>
<thead>
<tr>
<th>Injection Pressure (kPa)</th>
<th>Time Period</th>
</tr>
</thead>
<tbody>
<tr>
<td>2500</td>
<td>January 1st, 2001 ~ April 1st, 2001</td>
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<tr>
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<td>April 1st, 2001 ~ March 1st, 2002</td>
</tr>
<tr>
<td>1400</td>
<td>March 1st, 2002 ~ April 1st, 2003</td>
</tr>
<tr>
<td>2200</td>
<td>April 1st, 2003 ~ April 1st, 2004</td>
</tr>
<tr>
<td>1600</td>
<td>April 1st, 2004 ~ January 1st, 2005</td>
</tr>
<tr>
<td>1100</td>
<td>January 1st, 2005 ~ January 1st, 2006</td>
</tr>
<tr>
<td>1000</td>
<td>January 1st, 2007 ~ July 1st, 2008</td>
</tr>
</tbody>
</table>

The run time of the base case 2D model is reduced to 10 minutes. Simulation results show that the cumulative produced oil of the base case on July 1st, 2008 is 4,8931.8 m\(^3\), while the cSOR is 5.413 m\(^3\)/m\(^3\), which is too high. Steam chamber breaks through and top water collapses into the chamber at October 1st, 2003. The injection pressures at the beginning and end of the entire operation period are fixed at 2,500 kPa and 1,000 kPa, respectively, while the ones in the six consecutive intermediate time periods are selected as optimization parameters to be adjusted.
1. P₁: April 1st, 2001 ~ March 1st, 2002,
2. P₂: March 1st, 2002 ~ April 1st, 2003,
3. P₃: April 1st, 2003 ~ April 1st, 2004,
4. P₄: April 1st, 2004 ~ January 1st, 2005,
5. P₅: January 1st, 2005 ~ January 1st, 2006, and

Each parameter has sixteen discrete values from 1,000 kPa to 2,500 kPa, which are generated by an arithmetic sequence with the difference of 100 kPa. The Designed Exploration Controlled Evolution (DECE) optimizer was used to adjust parameters until the cSOR was minimized. The DECE optimizer narrows the discrete searching space by eliminating parameter values which may bring a high cSOR during the process. The parameters’ final status is shown in Table 4-5, in which the values with red background color are determined not suitable for optimization and eliminated finally. We notice that the remaining values mainly stay in the low pressure range from 1,000 kPa to 1,500 kPa, which is consistent with Gates and Chakrabarty’s (2005) conclusion.

The method converged after 1,124 simulation runs and the results show that cSOR is substantially reduced from 5.413 m³/m³ to 1.3354 m³/m³. Figure 4-10a shows the cSOR versus the number of simulation runs and the brown curves in Figure 4-10b indicate ten optimal strategies which bring minimum cSORs. Case # 1091 has the minimum cSOR of 1.3354 while others’ are less than 1.3506. However, even though cSOR is a measure of economic efficiency and, therefore, chosen as the objective function to be minimized, we may also have to take into
account the cumulative oil production which evaluates the effectiveness and return on invested capital (ROIC) of the strategy.

**Table 4-5 - Parameter status map**

<table>
<thead>
<tr>
<th>Parameter</th>
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<th>Value 2</th>
<th>Value 3</th>
<th>Value 4</th>
<th>Value 5</th>
<th>Value 6</th>
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<tr>
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<td>1500</td>
</tr>
<tr>
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</tr>
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</tbody>
</table>

**Figures 4-11a and 4-11b** compare the performance of ten optimal cases. The figures clearly show that Case # 1091 with the minimum cSOR may not provide the best operation strategy since its cumulative oil production is the least in the optimal cases. On the other hand, the result of Case # 1108 is more attractive. Although its cSOR is greater than that of Case # 1091 by 0.0152 m³/m³, it gives the highest cumulative oil production of 54,262 m³, which is increased by 6,559 m³ compared to the base case. Details of the ten injection pressure strategies and their corresponding results are summarized in Table 4-6.

The j x k two-dimensional cross-sectional views of water saturation at the moment of breakthrough of the base case, Case #1091 (minimal cSOR), Case #1108 (highest cumulative Oil production), and Case #691 are shown in **Figure 4-12**. The steam chamber breakthrough time is postponed to March 1st, 2007 by using the optimal strategy. It prevents top water from collapsing and draining into the chamber in an early stage (October 1st, 2003) of the production and saves
steam usage. **Figure 4-13** compares the temperature profiles which measure the steam chamber growth. The steam chambers in Case #1108 and Case #691 are nicely developed and wider than that of Case #1091. This causes a higher cumulative oil production because more oil in the horizontal direction is involved in drainage. The base case has a chamber which is very narrow around the well pair and wide in the top of the reservoir. This is due to its early steam breakthrough since the chamber cannot trap the steam and most of the steam travels into the top water region.

The effectiveness of injection pressure optimization lies in its economic performance of lowered cSOR and increased cumulative oil production. Additionally, less natural gas and water usage ensures the technique more energy efficient and environmentally friendly.

**Figure 4-10** - cSOR versus the number of simulation run during injection pressure optimization (10a); cSOR curves during injection pressure optimization (10b)
Figure 4-11 - Comparison of cumulative oil production of ten optimal cases (11a); Comparison of the cSOR of ten optimal cases (11b)

Figure 4-12 - Water saturation at the moment of breakthrough
Figure 4-13 - Temperature profiles on March 1st, 2007
Table 4-6 - Summary of the injection pressure optimization results

<table>
<thead>
<tr>
<th>Case #</th>
<th>Cum. Oil (m$^3$)</th>
<th>cSOR (m$^3$/m$^3$)</th>
<th>$P_1$ (kPa)</th>
<th>$P_2$ (kPa)</th>
<th>$P_3$ (kPa)</th>
<th>$P_4$ (kPa)</th>
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</table>

4.4.2 Steam Trap Control with Top Thief Zones

The objectives of the Surmont pilot SAGD simulations are to obtain an optimized steam-injection strategy and produce a reasonable cSOR for the McMurray reservoir with top thief zones. With a closer exam of the field performance with the effect of the steam trap control and steam injection pressure for the history matched model of Surmont, the three well pairs start up with relatively higher steam trap values: Pair A starts up at 30°C and remains between 15-20 °C; Pair B starts up at 30°C and remains between 10-15 °C; Pair C starts up at 30°C and remains between 10-15 °C. Simulation shows that subcool 40°C is not economical for all three well pairs. Steam trap 30°C at start up yields the lowest cSOR and the same amount of oil production. For
Pair B, the steam trap control of 30°C is good at start up; 15°C should be switched as the optimal case for Pair B. For Pair C, steam trap is set at 30°C for start up and 10°C after year 2002 as the optimal case. Therefore, higher subcool 30°C at SAGD starting up followed by lower subcool 10°C is the optimal case.

The optimization of three-well pairs full field model of the Surmont pilot SAGD simulation was achieved by manually adjusting the subcool control in different time periods. Furthermore, the CMOST computer-assisted optimization tool is utilized in finding the optimal subcool values for each operation period. Injection pressure strategy of Case # 1108 from previous optimization is used as a base case with five time intervals. The run time of the base case is about 10 minutes. Its cSOR is $1.3692 \text{ m}^3/\text{m}^3$ and cumulative oil production is $49,192 \text{ m}^3$ at the end of the production. Steam trap control values in the above five time periods are considered as optimization parameters in this stage:

1. Subcool$_1$ = 20°C, January 1$^{st}$, 2001 ~ January 1$^{st}$, 2002
2. Subcool$_2$ = 15°C, January 1$^{st}$, 2002 ~ January 1$^{st}$, 2004
3. Subcool$_3$ = 10°C, January 1$^{st}$, 2004 ~ January 1$^{st}$, 2006
5. Subcool$_5$ = 5°C, January 1$^{st}$, 2007 ~ January 1$^{st}$, 2008

Each parameter has four discrete values between 5°C to 40°C (Table 4-7).
Table 4-7 - Discrete values used in steam trap control optimization

<table>
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<tr>
<th>Parameters</th>
<th>Time Period</th>
<th>Discrete Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Subcool₁</td>
<td>January 1ˢᵗ, 2001 ~ January 1ˢᵗ, 2002</td>
<td>15, 20, 30, 40</td>
</tr>
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<td>Subcool₂</td>
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</tr>
<tr>
<td>Subcool₃</td>
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<td>Subcool₄</td>
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<td>Subcool₅</td>
<td>January 1ˢᵗ, 2007 ~ January 1ˢᵗ, 2008</td>
<td>5, 10, 15, 20</td>
</tr>
</tbody>
</table>

Again, the DECE optimizer was used to search for the minimum cSOR in the discrete parameter space. The optimal subcool control strategy (Case # 57) with the minimum cSOR of 1.3075 m³/m³ was obtained after 105 simulation runs (Figure 4-14a). The cSOR was further reduced by 0.0617 m³/m³. The plots of cSOR of all case runs in the optimization process are shown in Figure 4-14b. Ten optimal steam trap control strategies are summarized in Table 4-8. In the sense of economic performance, Case # 35 provides the best strategy because it yields the highest cumulative oil production of 54,097 m³. The results show that 40 °C is not suitable for an economic performance so that it was not used in any of the ten optimal strategies. It is consistent with our previous observation. The trend of subcool control in the best case is using a relatively higher value in the early stage of the operation and followed by a lower subcool control value thereafter.
Figure 4-14 - cSOR versus the number of simulation run during steam trap control optimization (14a); cSOR curves during steam trap control optimization (14b)

Table 4-8 - Summary of the steam trap control optimization results

<table>
<thead>
<tr>
<th>Case #</th>
<th>Cum. Oil (m³)</th>
<th>cSOR (m³/m³)</th>
<th>Subcool₁ (°C)</th>
<th>Subcool₂ (°C)</th>
<th>Subcool₃ (°C)</th>
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<tr>
<td>35</td>
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<td>1.3357</td>
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<td>10</td>
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<tr>
<td>52</td>
<td>42721</td>
<td>1.34</td>
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<td>30</td>
<td>10</td>
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<tr>
<td>Basecase</td>
<td>49192</td>
<td>1.3692</td>
<td>20</td>
<td>15</td>
<td>10</td>
<td>5</td>
<td>5</td>
</tr>
</tbody>
</table>
4.5 Conclusion and Discussion

The CMOST computer-assisted tool is used in the history matching of the single well pair model. Not only does this semi-automatic process minimize the global objective function – relative history match error, but also it saves time on traditional manually adjusting parameter work. Six matches have been found with the relative history match error less than 7%, and the best match has reduced the error to 4.6901%. Thief zone SAGD performance is more sensitive to the injection pressure. A higher injection pressure has caused the earlier steam breakthrough into the top water zone and water drains into the steam chamber.

Sensitivity runs on the 2D and 3D models have yielded the same optimal subcool at 10-30°C for the three well pairs. Controlling steam subcooling and varying the injection pressure lead to the optimum steam chamber operating strategy. The injection pressure strategy varies for each well pair: Pair C needs higher injection pressure at start up compared to pairs A and B; however, three well pairs share the common characters: 1,000 kPa is the optimal injection pressure when the steam approaches the top water at later time.

Optimization through varying the injection pressure and steam trap control leads to the optimal steam chamber operating strategies. In general, the strategy with higher injection pressure at start up, followed by lower injection pressure when the steam approaches the top theft zones results in high economic performance and energy efficiency. The results show that the cSOR can be lowered below 2.0, while high cumulative oil production is achieved. Steam trap control optimization is also performed. The cSOR is further reduced, while the best subcool strategy which reaches the cumulative oil production at 5,4097 m³ is using a higher value in the beginning and a lower value thereafter.
Chapter Five: ES-SAGD

5.1 Introduction

Expanding Solvent-SAGD (ES-SAGD) is the co-injection of small amount solvent additive with steam in the SAGD process. Solvent will condensate at the boundary of the steam chamber and diffuse into bitumen, which will reduce the oil viscosity, yield higher oil drainage and reduce the amount of steam required.

5.2 Review of ES-SAGD Process

Nasr et al. (2002 and 2003) reported the concept of ES-SAGD with detailed laboratory test results, which demonstrated that the highest drainage rate occurs when the vaporization temperature of the hydrocarbon additive become closer to the injected steam temperature. Das (2005) investigated the diffusion and dispersion of solvent in the VAPEX process. He presented the results of a simulation study to investigate partitioning of solvent components inside the vapor chamber. In general, it is expected that the non-condensable solvent components hinder the process. He indicated that the non-condensable solvent components accumulate at the solvent vapour and viscous oil interface. The solvent component diffuses through this vapor boundary layer to the oil interface. However, the rate of diffusion in the gaseous phase is much faster than that of the molecular diffusion in the liquid phase.

Gupta and Gittins (2005 and 2006) described field testing of a Solvent Aided Process (SAP) at the Senlac and Christina Lake SAGD Project. They indicated that significant benefits were resulted from the steam chamber lateral expansion due to the solvent injection. Additionally, the impact of timing of solvent initiation and the well pair spacing on process performance were also explored based on modeling exercises. Boak and Palmgren (2007) presented a numerical
analysis for a Naphtha Co-injection Test during SAGD for the MacKay River McMurray Formation. The effects of co-injecting a multi-component solvent, naphtha, and a single component solvent, propane or pentane, were investigated. Co-injection of any of the solvents studied (propane, pentane and naphtha) resulted in an improved SOR. Only naphtha co-injection resulted in an improved oil production rate because the components of naphtha travelled freely in the vapour chamber and accumulated along the vapour chamber front in both the vapour and oil phases.

Ivory et al. (2008) investigated the low pressure ES-SAGD through lab experiments and numerical simulations. They stated that the effects of minimum production pressure, sub-cool and solvent concentration must be considered simultaneously as they impact each other. Sensitivity runs on minimum BHP concluded that a lower producer BHP yielded a higher oil rate with less SOR. Govind et al. (2008) implemented detailed simulation studies for ES-SAGD. They stated that the important factors that control the performance of the ES-SAGD process are the solvent type, concentration, operating pressure and the injection strategy. The results of sensitivity studies performed on the solvent selection, dilation effect and operating condition were presented with conclusions and recommendations for an operating strategy. They also indicated the dilation is an important factor in the high pressure injection SAGD process. Ayodele et al. (2010) presented experimental tests and history-matched simulation results of 2D scaled laboratory tests of ES-SAGD with hexane as the co-injected solvent. The comparison of ES-SAGD and SAGD experiments shows that ES-SAGD using hexane performed better than an equivalent SAGD experiment. Deng et al. (2008) simulated the ES-SAGD process with a solvent mixture in Athabasca reservoirs using a pseudo component scheme to represent the complex
solvent mixture in the numerical model, based on the diluents’ composition and measured PVT data. The behavior and effects of the co-injected solvent in the ES-SAGD process were analyzed through detailed history matching of the ES-SAGD test. They demonstrated that higher solvent solubility corresponding to the lower K value increased oil production in the ES-SAGD process.

5.3 K – Factor Calculation

To calculate the chemical potential of a component of a mixture the following formula is used:

\[ dG_j = RTd(\ln f_j) \quad 5.1 \]

When pressure of the fluid approaches zero, nearing its ideal behaviour, the fugacity of a component approaches partial pressure of the component.

\[ \lim_{p \to 0} f_j = y_j p = p_j \quad 5.2 \]

While at equilibrium, the component in the gas and liquid phase must have equal fugacity. Then the equilibrium of gas-liquid can be calculated using the following relation for all components:

\[ f_{ij} = f_{ij} \quad 5.3 \]

An equation of state is used to calculate fugacity for each component. For each component of a mixture, the fugacity coefficient is defined as the ratio of fugacity to partial pressure.

\[ \phi_j = \frac{f_j}{y_j p} \quad 5.4 \]

To calculate the fugacity coefficient, the following formula is used:

\[ \ln \phi_j = \frac{1}{RT} \int_{v}^{\infty} \left[ \frac{RT}{V} - \left( \frac{dP}{d\eta_j} \right)_{V, m} \right] dV - \ln Z \quad 5.5 \]

To calculate a K-factor, the ratio of the fugacity coefficients can be used
\[
K_j = \frac{\phi_{ij}}{\phi_{ij}} = \frac{\frac{f_{ij}}{x_i p}}{\frac{f_{ji}}{y_j p}} = \frac{y_j}{x_j}
\]

when \( f_{ij} = f_{ji} \) at the equilibrium (Dong, 2011),

where

\( G_j \): Chemical potential of a component of a mixture

\( K_j \): The ratio of vapor concentration to liquid concentration at equilibrium

\( f_{ij} \): Fugacity of the component in the gas phase

\( f_{ji} \): Fugacity of the component in the liquid phase

\( \phi_j \): Fugacity coefficient

\( y_j \): The mole fraction of vapor

\( x_j \): The mole fraction of liquid

\( R \): Idea gas constant

\( V \): Volume of the gas

\( T \): Temperature of the gas

\( p \): Pressure of the gas

\( Z \): Compressibility factor

### 5.4 Solvent characterization using WinProp

A solvent mixture (10% volume) ranging from C4 to C11 is characterized using Winprop and exported into STARS for the ES-SAGD simulation. STARS uses a K-Value based fluid model, in which a two-phase equilibrium description defined by K-Values is determined. Liquid
viscosities in STARS are inputted as tables with respect to temperature and pressure, and then follows a non-linear mixing rule for both the oleic and water phases. A single well solvent injection approach is implemented, where the volume fractions are properly defined for each solvent component and water at surface conditions. Three pseudo components are lumped by matching the solvent liquid density and saturation pressure based on the experimental data using CMG Winprop (Table 5.1). The solvent mixture consists of mole fraction 66.63% of IC4-NC5, 35.35% of C6-C8 and 2.31% C9-C11. Solvent is continuously injected with steam at 10% volume fraction. Injection varies from 2,000 kPa at the start-up and drops to 1,000 kPa because of the top thief zone in presence. Subcool is kept at constant 10 °C. Simulation results showed that cumulative oil production was increased by 1.0e+5 Sm³ and cSOR dropped to 3.0 from 6.0 (SAGD case). Steam chamber grows more laterally in the bitumen interval compared to the SAGD case (Figure 5-1). The solvent concentration profile of the interface shows that IC4-NC5 mostly exists in the vapour phase, while C9-C11 most exists in the oil phase. C6-C8 exists in both the oil and gas phases (Figure 5-2). Most of C6-C8 and C9-C11 are produced with oil in the liquid phase, and very little is produced from the gaseous phase.

**Table 5-1- Properties of the pseudo component in solvent mixture**

<table>
<thead>
<tr>
<th>Component</th>
<th>Molecular Weight (kg/gmole)</th>
<th>Mole Density (g/mole/m³)</th>
<th>Mass Density (kg/m³)</th>
<th>Compressibility (1/kPa)</th>
<th>Thermal Expansion (1/C)</th>
<th>Critical Pressure (kPa)</th>
<th>Critical Temperature (Cels)</th>
</tr>
</thead>
<tbody>
<tr>
<td>IC₄ to NC₅</td>
<td>6.51E-02</td>
<td>1.05E+04</td>
<td>684.9</td>
<td>1.68E-06</td>
<td>1.15E-03</td>
<td>3431.92</td>
<td>147.57</td>
</tr>
<tr>
<td>C₆ to C₈</td>
<td>9.63E-02</td>
<td>7514</td>
<td>723.6</td>
<td>1.13E-06</td>
<td>7.88E-04</td>
<td>3123.8</td>
<td>268</td>
</tr>
<tr>
<td>C₉ to C₁₁</td>
<td>0.134</td>
<td>5828</td>
<td>781</td>
<td>8.55E-07</td>
<td>6.04E-04</td>
<td>2530.65</td>
<td>348.86</td>
</tr>
</tbody>
</table>
Figure 5-1 - Steam chamber profiles of different solvent mixture. A: IC$_4$-NC$_5$; B: C$_6$-C$_8$; C: C$_9$-C$_{11}$; D: Solvent mixture (C$_4$-C$_{11}$).

Figure 5-2 - Solvent mole fractions in the steam chamber interface. A: IC$_4$-NC$_5$; B: C$_6$- C$_8$; C: C$_9$-C$_{11}$; D: Solvent mixture.
5.5 ES-SAGD Simulation

Three pseudo components solvents IC₄-NC₅, C₆-C₈ and C₉-C₁₁ are characterized and simulated separately to investigate their effects during the ES-SAGD. IC₄-NC₅ produces less oil compared to the base case SAGD because lighter component IC₄-NC₅ remains mostly in the gas phase in the steam chamber interface, which impedes the oil rate because it prevents the heat transfer from steam to the adjacent bitumen. C₉-C₁₁ yields the highest oil rate with the lowest cSOR at 2.0, with greater lateral expansion of the steam chamber compared to the SAGD case (Figures 5-3, 5-4 and 5-5) because pseudo component C₉-C₁₁ has the highest solubility with the lowest K value compared to other components. Also, this heavier component slows down the steam from moving upward, causing the greatest steam chamber lateral growth in the lower part of the bitumen interval. C₆-C₈ solvent is carried by the steam towards the steam chamber interface; therefore, the chamber is shifted up in the top thief zone. To summarize, hexane C₆ injection improves the bitumen recovery which is consistent with previous publications; however, the optimized solvent co-injection for the top thief zone case should be the solvent mixture containing the heavier component C₉-C₁₁.
Figure 5-3 - Solvent co-injection improves the oil production except solvent mixture IC$_4$-NC$_5$, which yields the lowest oil rate less than the SAGD case. Solvent mixture C$_9$-C$_{11}$ yields the highest oil rate.

Figure 5-4 - Solvent co-injection improves the oil production except solvent mixture IC$_4$-NC$_5$. Solvent mixture C$_9$-C$_{11}$ yields the highest oil rate.
Figure 5-5 - Solvent mixture IC$_4$-NC$_3$ yields the highest cSOR (above 6.0); solvent mixture C$_6$-C$_8$, C$_9$-C$_{11}$ and C$_4$-C$_{11}$ yields the optimal cSOR (about 2.0).

5.6 Conclusion and discussion

A full field simulation model for the Surmont SAGD pilot has been history-matched and optimized. Expanding solvent simulation has been implemented. Regarding SAGD related solvent co-injection modeling, we conclude that Hexane C6 injection improves the bitumen recovery which is consistent with previous publications; however, the optimized solvent co-injection for the top thief zone case should be the solvent mixture containing the heavier components C9- C11.
Chapter Six: Geomechanical Simulation of ES-SAGD Process

6.1 Introduction

In the SAGD process, continuous steam injection changes reservoir pore pressure and temperature, which can alter the effective stress in-situ. Dilation behavior associated with volumetric strains is triggered by the continuous steam injection, which causes the increase of porosity and permeability. Therefore, the fluid flow behavior must be coupled to the geomechanical behavior of the oil sands. Investigating the interaction between the cap rock integrity, dilation and thermal expansion under the continuous steam injection is the focus of this study.

6.2 Literature Review

The literature has documented numerous geomechanical studies for the SAGD process (Agar, 1984; Vaziri, 1989 and 1990; Settari, 1989 and 1992; Chalaturnyk, 1996; Ito and Suzuki, 1996; Touhidi-Baghini, 1998; Collins et al., 2002).

Agar (1984) conducted a geotechnical testing of undisturbed Alberta oil sands at elevated temperature and pressures in his PhD thesis. He documented a detailed procedure in setting up the test facilities to investigate the effective permeability changes, thermal expansion and compaction effects on the stress-strain behavior for oil sands samples. Through drained and undrained lab tests, he concluded that the effective permeability of oil sands increased at elevated temperature. In addition, a large volumetric strain due to the thermal expansion generates significant in-situ stress. Vaziri (1989 and 1990) proposed a modified nonlinear elastic hyperbolic stress-strain model for Athabasca oil sands under triaxial conditions based on numerical experiments. He presented a mathematical formulation in modeling the dilations:
shear-induced dilation and stress-ration-induced dilation. Through numerical experiments using
the proposed model, simulation of triaxial tests on oil sands match the lab experiments
reasonably well.

Settari et al. (1989) proposed a method of coupling fluid flow and soil behavior to model
injection into uncemented oil sands. They stated that geomechanical properties of geomaterials
were the key elements; therefore, the fluid flow behavior must be coupled to the mechanical
behavior of the oil sands. Settari (1992) investigated the physics and modeling of thermal flow
and soil mechanics in unconsolidated porous media. He indicated that the dilation behavior
associated with volumetric strains was an important feature, which causes an increase of porosity
and permeability. A new formulation of nonlinear soil mechanics and multi-phase flow was
developed which represented the physics of the thermal process. Numerical implementation of
coupled solutions and a method of handing the nonlinearity were presented in detail. Settari et al.
(1992) described the geotechnical aspects of recovery processes in oil sands. The behavior of
constitutive models in the low effective stress range was re-examined by setting the limit for a
maximum friction angle, which eliminated the non-physical behavior at low confining stresses.
A generalized hyperbolic model was proposed with two arbitrary exponents, which agreed with
the laboratory experiment data. They emphasized the importance of reaching the zero minimum
effective stress in the lab condition in order to mimic the field conditions.

Fung et al. (1994) described a novel numerical model for the solution of poro-elasto-plasticity
and multiphase, thermal flow in unconsolidated heavy oil and oil-sand reservoirs. The elastic-
plastic deformation is calculated using a finite-element incremental plasticity model with Mohr-
Coulomb and Drucker-Prager as the yield criteria. This model is coupled with CMG's thermal
simulator STARS. The volume change is calculated by the plasticity model, whereas the permeability increase is related to the volume changes via tabular data.

Chalaturnyk (1996) assessed the geomechanical effects for the UTF SAGD process by utilizing the experimental and numerical analysis. Field observations have shown that formation displacements were induced in the reservoir, which significantly influenced reservoir properties. An empirical correlation between the absolute permeability and volumetric strain has been developed, which shows that the absolute permeability has increased approximately 30% due to the changing of the volumetric strain. A decoupled approach using the flow simulator ISCOM and stress simulator FLAC was developed in predicting the shear induced dilation and thermal expansion. He concluded that stress-strain behavior (shear-induced dilation, porosity, permeability and effective confining stress) was a concurrent process which alters the reservoir condition in advance of the steam chamber. Ito and Suzuki (1996) conducted numerical simulation of the SAGD process in the Hangingstone oil sands reservoir. Shear dilation was approximately simulated by setting porosity and permeability as a function of pressure. Comparison of the oil rate with and without geomechanical coupling (sand deformation model in STARS) showed the significant difference in terms of the steam chamber.

Touhidi-Baghini (1998) implemented an experimental study for the change in the absolute permeability of oil sands at low confining pressure. A method of continuous measurement of permeability during shear was developed. Furthermore, laboratory tests were implemented into the constitutive model using the stress simulator FLAC. He concluded that the absolute permeability of oil sands increased dramatically during the shear dilation. Finally, a correlation of absolute permeability and volumetric strain was developed. Li (2006) presented a numerical
simulation for the SAGD process coupled with reservoir geomechanics in his PhD thesis. A modular approach was used by linking thermal simulator EXOTHERM with the stress simulator FLAC. Numerical experiments were conducted by matching the lab tests. The proposed model was further validated using the UTF (Underground Test Facility) historical production data.

6.3 Coupled Geomechanical Modeling

Settari and Walter (2001) discussed the following five coupling methods in solving the reservoir flow and geomechanical stress equations: uncoupled, weakly coupled, explicitly coupled, iteratively coupled, and fully coupled methods. The un-coupled method does not take into account the geomechanical effects during the reservoir simulation. Therefore, it is not adequate to represent the real physics of the SAGD process, where porosity and permeability are changing due to the variation of the stress. Weakly coupled is typically applied to the permeability coupling only, and iteration within each time step is not required because changes of the permeability are always mass conservative. The explicit coupling approach is a special case of the iterative approach, which allows the porosity coupling lagged one time step behind. The iterative coupled method sequentially solves the stress and flow equations at each time step by the iterations between the reservoir simulator and geomechanical simulator. The fully coupled method solves the flow and stress equations simultaneously and requires a significant computation time. The iterative coupling method has the advantage of flexibility and computational efficiency in coupling the finite difference discretization (reservoir flow model) and finite element discretization (stress model) together (GEOSIM, 2010). Figure 6-1 shows the geomechanical iteration within one time step for the iterative coupling method. The general
formulation of a coupled problem in FEM discretization can be written as (Settari and Walter 2001):

\[
\begin{bmatrix}
  K & L \\
  L^T & E
\end{bmatrix}
\begin{bmatrix}
  \Delta \delta \\
  \Delta P
\end{bmatrix} =
\begin{bmatrix}
  F \\
  R
\end{bmatrix}
\]

6.1

Where:

- \( K \): Stiffness matrix
- \( \delta \): Displacement vector
- \( L \): Coupling matrix to flow unknowns
- \( E \): Flow matrix
- \( P \): Vector of reservoir unknowns (i.e., pressures, saturations and temperature)
- \( F \): Vector of force boundary conditions
- \( R \): Right hand side of the flow equations
- \( \Delta \): Change over time step

Equation \( K\Delta \delta + L\Delta P = F \) represents the geomechanical equilibrium and \( L^T\Delta \delta + E\Delta P = R \) represents the flow equation coupled with reservoir geomechanics through the coupling matrix \( L \).

In the iterative coupling (modular solution) approach, the stress and flow equations are solved separately but the solutions are exchanged between the reservoir simulator and geomechanical simulator. The reservoir simulator solves equation \([T(\delta) - D]\Delta P = Q - T(\delta)P' - L^T\Delta \delta \); the geomechanical simulator solves equation \( K(P)\Delta \delta = F - L\Delta P \).
6.4 Porosity and Permeability Coupling

Settari and Mourits (1998) defined the pore volume coupling formulation by introducing the "apparent porosity" $\phi^*$, expressed as: $\phi^* = \phi(1 - \epsilon_v)$. The general equilibrium formulation of the porosity coupling is defined as:

$$\phi_{n+1}^* = \phi_n^* + \phi_v \left[ c_p \Delta p - c_T \Delta T \right] - \left[ c_p \phi_v (1 - \epsilon_v) + c_b \phi_n^* \right] \Delta \sigma_m$$  \hspace{1cm} (6.2)

Tran et al. (2002 and 2004) improved the porosity coupling by considering the changing of the volumetric strain $\epsilon_v$ (the last term on the right-hand side of equation (6.3), which is not always zero). Tran et al.’s model in the following equation (6.3) is a general form of Settari’s model expressed by equation (6.2), which improves the solutions with faster convergence and less CPU
time. Pore volume coupling between STARS and the geomechanical model is used in Tran et al.’s formulation.

The formulation of the improved porosity coupling is defined as:

\[
\phi^*_{n+1} = \phi^*_{n} + \phi_{n} \left[ c_p \Delta p - c_T \Delta T \right] - \left[ c_p (1 - \varepsilon_v^n) + c_p \phi_{n} \right] \Delta \sigma_m + \left[ -(c_b - c_r) \Delta p + c_b \Delta \sigma_m - \beta \Delta T \right] \phi_n \varepsilon_v^n
\]

where:

- \( \phi_{o} \): Initial porosity
- \( \phi \): True porosity
- \( c_p \): Pressure coefficient
- \( c_T \): Temperature coefficient
- \( c_\phi \): Porosity compressibility
- \( c_b \): Bulk compressibility
- \( c_r \): Rock compressibility
- \( \beta \): Volumetric thermal expansion coefficient
- \( \sigma_m \): Mean total stress
- \( \varepsilon_v \): Volumetric strain

The permeability and volumetric strain correlations are derived using the following empirical equation (Touhidi-Baghini, 1998):

\[
\ln \frac{k_2}{k_1} = C_w \varepsilon_v
\]

where:

- \( k_2 \): Current absolute permeability
\( k_i \): Original absolute permeability

\( C_{nl} \): Proportional constant

\( \varepsilon_v \): Volumetric strain

### 6.5 Oil Sand Constitutive Model

For the coupled geomechanical simulation, a constitutive model that approximates the behavior of geomaterials under various stresses, boundary conditions, loading paths, pore pressures and temperatures must be developed before the simulation work. In a thermal recovery process with steam injection, the geomechanical behavior of oil sands is the main factor governing the injectivity since the porosity and permeability increase caused by the dilation is the principal mechanism which has an effect on the injectivity (Settari et al., 1989).

Duncan and Chang (1970) presented a hyperbolic stress-strain relation model based on tri-axial soil tests. This model assumes a constant Poisson's ratio. Duncan et al. (1980) proposed a revised model which accommodates the variation of Poisson’s ratio by means of stress-dependent Poisson’s ratio and stress-dependent bulk modulus. Vaziri (1989) proposed a new constitutive stress-strain model to describe the geomechanical behavior of oil sands. It was developed based on three fundamental theories: (1) the hyperbolic nonlinear elastic behavior prior to yielding, (2) the critical-state elastic-plastic behavior following yielding, and (3) the Mohr-Coulomb criterion at failure. This model is suitable in modeling a geomechanical problem in oil sands. Wan et al. (1991) developed a constitutive model for the effective stress-strain behavior of oil sands, which characterized stress and thermal conditions under triaxial tests. The proposed model combined the Ramber-Osgood hardening-softening function, Matsuoka-Nakai failure criteria and Rowe’s
stress dilatancy model. Therefore, it captured the strain softening at low confining pressures and
temperature as well as the hardening at high confining pressures and temperature.

6.6 Duncan and Chang’s Standard Hyperbolic Model:

Based on standard tri-axial soil tests, the model approximates the stress-strain relation by the
following hyperbolic relation (Duncan et al. 1980).

The initial modulus $E_i$ is defined as:

$$E_i(\sigma_i') = k_E P_a (\frac{\sigma_i'}{P_a})^{n_i}$$  

The tangent young’s modulus $E_t$ is given by:

$$E_t = E_i(\sigma_i') f(\sigma_{\text{dev}}')$$  

The tangential bulk modulus $B_m$ is:

$$B_m = k_B P_a (\frac{\sigma_i'}{P_a})^{n_b}$$  

The shape function is expressed as

$$f(\sigma_{\text{dev}}') = \left[1 - R_f \left(\frac{(\sigma_i' - \sigma_{\text{dev}}')}{(\sigma_i' - \sigma_{\text{dev}}_{\text{ult}})}\right)\right]^2$$

The tangent modulus $K_t$ is given by

$$K_t = K_B P_a (\frac{\sigma_i'}{P_a})^{n_k}$$

Poison’s ratio is a function of $\sigma_i'$ and $\sigma_{\text{dev}}'$:

$$v = \frac{1}{2} - \frac{k_E}{6k_B} (\frac{\sigma_i'}{P_a})^{n_m} f(\sigma_{\text{dev}}')$$

The failure ratio $R_f$ is defined as:

$$R_f = \frac{(\sigma_i' - \sigma_{\text{dev}}')}{(\sigma_i' - \sigma_{\text{dev}}'_{\text{ult}})}$$
6.7 Generalized Hyperbolic Model:

Settari et al. (1993) pointed out the dilation behavior as an important geomechanical feature of Alberta oil sands. Dilation is associated with volumetric strain and the changes in fluid transport properties, and is a function of effective stress and sand failure. They stated that the nonlinear mechanical properties within the region of very low effective stress have the significant impact on the fluid flow. The conventional hyperbolic model (Duncan and Chang 1970; Duncan et al., 1980; Varizi, 1989 and 1990) predicted the anomaly results without a reasonable limitation on the maximum friction angle. Therefore, the conventional assumption $\varphi_{\text{max}} = \varphi_0$ is arbitrary. By limiting a friction angle to the highest value measured by Agar (1984), the abnormal behavior can be eliminated. The standard hyperbolic models were not able to match the laboratory data. A generalized hyperbolic constitutive model was developed by introducing two arbitrary exponents in the shape function equation, which successfully matched stress-strain data for the McMurray oil sands.

$$f(\sigma_{\text{ave}}) = 1 - \left( R_j \frac{(\sigma_i - \sigma_{\text{f}})}{(\sigma_i - \sigma_{\text{f}})} \right)^{e_1}$$

where:

$e_1$ and $e_2$ are arbitrary exponents.

The tangential Young’s modulus $E_t$ is:

$$E_t = E_i \left[ 1 - \left( R_j \frac{(\sigma_i - \sigma_{\text{f}})}{(\sigma_i - \sigma_{\text{f}})} \right)^{e_1} \right]$$
6.8 Thermal Constitutive Model

Agar (1984) described a relationship between the thermal expansion and pore pressure generation in oil sands. The thermal pore pressure generation coefficient was evaluated in undrained heating experiments under constant total confining stresses and under constant effective confining stresses. The thermal strain caused by the temperature in one dimension is expressed as $\varepsilon_r = -a_r \Delta T$. Therefore, the stress needed to create the $\varepsilon_r$ is $\sigma_r = a_r E \Delta T$. $a_r$ is the linear thermal expansion coefficient. Bulter (1986) investigated the expansion of oil sands during the thermal recovery based on one-dimensional Newtonian flow. He stated that thermal expansion creates a large pore pressure during the thermal recovery. Because of the high viscosity that prevents the pressure relief, this high pressure can fracture the matrix and extend into the reservoir.

Settari and Walter (2001) proposed an empirical modification of the constitutive model for thermo-elasticity by introducing the thermal compaction and stiffening modifications. It consists of modifying the equations for the thermal expansion term, modulus and bulk modulus as a function of temperature, including hysteresis effects.

\[
\sigma_{ij} = 2G \left[ \varepsilon_{ij} + \frac{\nu}{1-2\nu} \left( \varepsilon_r - \frac{1+\nu}{\nu} a_r T \right) \right] - \alpha p \delta_{ij} \tag{6.14}
\]

\[
a_r = \alpha_t + \alpha_{\text{comp}} \tag{6.15}
\]

\[
\alpha_{\text{comp}} = K_u \left( \frac{T}{T_{\text{ref}}} \right)^n
\]

where:
\( \alpha_{\text{comp}} \): is a nonlinear parameter describing the thermal compaction with respect to a change in temperature.

\( K_a, n_a \): are input coefficients governing the shape of the parameter.

\( T_{\text{ref}} \): is the reference temperature at which the thermal compaction is zero.

Therefore, the nonlinear constitutive model was modified by the additional constants exponents \( m_c \) and \( m_b \), which control the shape of the thermal dependence functions in calculating Young’s modulus and the bulk modulus:

\[
E_i(\sigma_i) = k_E P_a \left( \frac{\sigma_i}{P_a} \right)^{n_i} \left( \frac{T}{T_{\text{ref}}} \right)^{m_i} \\
\sigma_i = \sigma_3' + c \frac{m}{\tan(\phi_{\text{max}})} \\
B_m = k_m P_a \left( \frac{\sigma_r}{P_a} \right)^{n_r} \left( \frac{T}{T_{\text{ref}}} \right)^{m_r}
\]

6.16

6.17

6.18

### 6.8.1.1 Failure Criteria:

The failure envelope is defined by a Mohr-Coulomb failure criterion \( \tau' = c + \sigma' \tan \phi \), controlled by the friction angle which is calculated as:

\[
\varphi = \varphi' - \Delta \phi \log \left( \frac{\sigma_3'}{P_a} \right)
\]

6.19

The Mohr-Coulomb failure condition is written in terms of the principal stresses as:

\[
\sigma_1' - \sigma_3' = (\sigma_1' - \sigma_3') = (\sigma_{\text{dev}}') = \frac{2c \cos \varphi + 2\sigma_3' \sin \varphi}{1 - \sin \varphi}
\]

6.20

The stress level is limited to one when the deviatoric effective stress reaches the failure envelope:
\[ L_{se} = \frac{\sigma_{\text{dev}}'}{\sigma_{\text{dev}}^*} \leq 1 \] 6.21

6.9 Coupled Geomechanical Modeling on SAGD

The single well pair (A) model has been simulated using the non-linear hyperbolic constitutive model in CMG STARS. The iterative coupling approach (two way coupling) is selected. It is a Cartesian 3-D geometry with the \( i \times j \times k \) dimensions at \( 6 \times 102 \times 40 \), converted from a corner point grid. Geomechanical properties of the rock for the non-linear hyperbolic constitutive model are listed in Table 6-1. The initial stress gradient is defined using the stress gradient 19.0 kPa/m for horizontal and 22.0 kPa/m for vertical (Collins et al. 2002). The non-linear hyperbolic constitutive model yields three distinct geomechanical periods associated with the steam injection and interactive with the top water thief zone (Figure 6-2).
Table 6-1- Geomechanical properties for the non-linear hyperbolic constitutive model inputs

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<td>$m$ (MCOEF)</td>
</tr>
</tbody>
</table>

*Geomechanical properties in the non-linear hyperbolic formulation are represented by the CMG keywords.*
Figure 6-2 - Illustration of three distinct geomechanical periods associated with the steam chamber growth and interactive with top water thief zone from the non-linear hyperbolic constitutive model.
The 1st unloading period: Dilation occurs when the mean effective stress decreases due to the steam injection. A stress path in the SAGD process is a combination of the pore pressure and thermal effects (Li et al., 2006). Increasing of the pore pressure due to steam injection reduces the effective mean stress; meanwhile, thermal expansion causes an increase of both stress differential and mean stress. Stress path moves towards the failure envelope and vertical displacement starts to increase as the steam chamber rises. The volumetric strain moves in the negative direction from the initial state, which increases the effective porosity and permeability (Figure 6-3). During the unloading period, the vertical displacement starts to increase until the steam chamber reaches the top water zone.

![Figure 6-3 - Coupled Geomechanical model corrected porosity and permeability; reflections are corresponding to the 3 periods.](image)

The reloading period: The field injection pressure drops from initial 2,000 kPa to 1,000 kPa when the steam approaches the top water zone. Simulation results show that this significant injection pressure drop failed to prevent the top water from draining into steam chamber. Additionally, the increasing of the water production causes a further reduction of the reservoir
pressure down to 850 kPa. As a result, the effective stresses increase; the recompaction occurs and the subsidence is observed. Volumetric strain moves to the opposite direction compared to the previous unloading path. Stress path is moving to the direction of increasing the effective stress, and deviating away from the failure envelop. Geomechanically corrected porosity and permeability both decrease in this period. Also, the falling of the temperature is observed because of the water quenching; hence, there is no further increase of the horizontal stresses caused by the thermal expansion at this stage. **Figure 6-4** demonstrates the interactions between the effective stresses, reservoir pressure, volumetric strains and temperature profile for a grid block located at top center of the reservoir.
Figure 6-4 - Interactions between the effective stresses, reservoir pressure, volumetric strain and temperature for top center of the reservoir (block 3, 51, 1).

As the steam chamber approaches the top of the reservoir, the 2\textsuperscript{nd} unloading period appears. Dilation is resumed and dominates at the top center of the reservoir where the steam breakthrough occurs, pushing the top water and gas away. The multi-wells SAGD pattern indicates that the highest dilation occurs above the steam injector and remains relative low in the inter-well region (Figure 6-5).
Eventually, the reservoir pressure is stabilized at 950 kPa as the steam chamber reaches the reservoir top and grows laterally. The vertical effective stress remains constant, whereas the horizontal stresses increase due to the thermal expansion. In addition, a slight increase of the vertical displacement is observed, which is caused by the thermal expansion in the vertical direction. Simulation results show that there is no further increase in porosity and permeability at 1,000 kPa injection pressure. **Figure 6-6** demonstrates the variations of the vertical displacement during these three distinct periods. Clearly, the dynamic changing of the geomechanical properties in the coupled model is not only associated with the steam injection and thermal expansion, but also interactive with the top water and gas thief zones.
The maximum surface heave at the reservoir top is about 0.3 meters after 10 years production, and gradually reduces away from the well pair. Stress level analyses of the McMurray Formation oil sands demonstrate the values greater than 1.0 and hence shear failure occurs (Walter, 2010). The largest stress level occurs above and adjacent to the developed steam chamber decreasing along the x-direction away from the wells. There is no failure occurring (the yield state value equals zero) for the non-linear hyperbolic constitutive models (two way coupling) under the field injection rate control. Because of the increasing of the geomechanically corrected porosity and permeability, the coupled non-linear hyperbolic model yields the larger cumulative oil production, which corresponds to these distinct geomechanical periods very well (Figure 6-7). Oil production increases as the dilation takes effect due to steam injection, decreases along with the development of subsidence caused by the pressure drop, and increases again in the second dilation period as the steam chamber rises. Therefore, the thermal-geomechanical coupled non-linear hyperbolic constitutive model provides a better solution in representing the physics of the SAGD process.
A dual grid system (reservoir grid plus geomechanical grid extended to surface) is invoked in elasto-plastic Mohr-Coulomb model to investigate the surface heave or subsidence. The geomechanical grid (10 x 25 x 21) is independent of the host simulator’s grid, which allows the geomechanical calculation on a larger grid block size compared to the flow grid, therefore improving the computational efficiency (Figure 6-8). However, because of the lack of the thermal coupling in the elasto-plastic Mohr-Coulomb formulation, larger-scale recompaction associated with the pressure drop becomes the dominated driving force during the 2nd period. As a result, subsidence occurs and remains until the end of the simulation (Figure 6-9). The minor reduction of the oil rate is observed in the two-way coupled elasto-plastic Mohr-Coulomb model. Simulation results show that the surface subsidence is about 0.1 meters after 10 years production. Compared to the non-linear hyperbolic model, the elasto-plastic Mohr-Coulomb model fails to capture the reality in this case.
Figure 6-8 - Geomechanical grid was extended to the surface to investigate the surface heave or subsidence. Geogrid contains the host reservoir grid using larger grid block to improve the computational efficiency.

Figure 6-9 - Three distinct geomechanical periods associated with the steam injection and interactive with top water thief zone. The surface subsidence is about 0.04m using dual grid system dual georock type (Geogrid extended to surface) by Elasto-Plastic Mohr-Coulomb model.

Dynamic changing of the geomechanical deformation, in-situ effective stresses and volumetric strains involved in the thermal-mechanical-fluid coupling process alter the rock properties, which eventually cause the steam redistribution as seen in the ES-SAGD case. The coupled ES-SAGD
model associated with a slight higher oil rate compared to the uncoupled ES-SAGD model is expected. However, the oil rate starts to drop below the uncoupled model after year 2006 (Figure 6-10). In the coupled ES-SAGD case, dilation enhanced high permeability zones lead to a higher steam chamber (solvent + steam) rising speed, which eventually causes a redistribution of the steam flow. Because the heel of the injector is located in a relative low permeability zone, the steam chamber growth has been delayed as seen in Figure 6-11. In addition, less dilation effect is observed in the coupled ES-SAGD case compared to the coupled SAGD case because of the lower reservoir pressure in the ES-SAGD case (Figure 6-12).

Figure 6-10 - Coupled ES-SAGD model associated with slight higher oil rate compared to the uncoupled ES-SAGD is expected as the dilation taking effect; Oil rate becomes lower after year 2006 because of the steam redistribution involved.
Figure 6-11 - In the coupled ES-SAGD case (left), steam chamber rises much slower in the relatively low permeability zone which is located at the heel of the injector.

Figure 6-12 - Less dilation effect is observed in the coupled geomechanical model for ES-SAGD compared to the coupled SAGD model.
6.10 Conclusions and Discussion

The thermal-geomechanical-fluid coupled non-linear constitutive model provides a better solution over the elasto-plastic Mohr-Coulomb model in representing the physics of the SAGD process with a top water thief zone.

Oil production increases as the dilation takes effect due to steam injection, decreases along with the development of subsidence, and increases again in the second dilation period as the steam chamber rises.

The non-linear constitutive model predicts the maximum surface heave at the reservoir top about 0.30 meters after 10 years production; therefore, significant surface deformation is not likely the case at the current field injection pressure.
Chapter Seven: Conclusions and Discussion

Geostatistical modeling is the most effective tool in capturing the reservoir heterogeneity and analyzing the uncertainty. It has a great impact on the dynamical simulation results. Modeling the steam baffle mudstones and mud breccias is critical in the facies modeling process.

Reservoir heterogeneity determines the steam chamber performance. Discontinuous mudstone acts as the steam baffle, which widens the chamber laterally.

The computer-assisted tool CMOST is used in the history matching of the single well pair model. Not only does this semi-automatic process minimize the global objective function – relative history match error, but also it saves time on traditional manually adjusting parameter work. Six matches have been found with the relative history match error less than 7%, and the best match has reduced the error to 4.6901%.

Thief zone SAGD performance is more sensitive to the injection pressure. A higher injection pressure has caused the earlier steam breakthrough into the top water zone and water drains into the steam chamber.

Sensitivity runs on the 2D and 3D models have yielded the same optimal subcool at 10-30°C for the three well pairs. Controlling steam subcooling and varying the injection pressure lead to the optimum steam chamber operating strategy. Injection pressure strategy varies for each well pair: Pair C needs higher injection pressure at start up compared to pairs A and B; however, three well pairs share the common characters: 1,000 kPa is the optimal injection pressure when the steam approaches the top water at later time.
Optimization through varying the injection pressure and steam trap control leads to the optimal steam chamber operating strategies. In general, the strategy that a higher injection pressure at start up followed by a lower injection pressure when the steam approaches the top thief zones results in high economic performance and energy efficiency.

In our study of a two-dimensional extracted model with well pair C using CMOST, the results have shown that the cSOR can be lowered to 1.3506 m³ / m³ while high cumulative oil production is achieved. Steam trap control optimization has also been performed. The cSOR is further reduced to 1.3075 m³ / m³, while the best subcool strategy which reaches the cumulative oil production of 54,097 m³ is using a higher value in the beginning and a lower value thereafter.

Hexane C6 injection improves the bitumen recovery which is consistent with previous publications; however, the optimized solvent co-injection for the top thief zone case should be the solvent mixture containing the heavier components C₉-C₁₁.

The thermal-geomechanical-fluid coupled non-linear constitutive model provides a better solution over the elasto-plastic Mohr-Coulomb model in representing the physics of the SAGD process with a top water thief zone. Oil production increases as the dilation takes effect due to steam injection, decreases along with the development of subsidence, and increases again in the second dilation period as the steam chamber rises.

The non-linear constitutive model predicts the maximum surface heave at the reservoir top about 0.30 meters after 10 years production; therefore, significant surface deformation is not likely the case at the field injection pressure.
References


Schlumberger (2009), Petrel user manual.


APPENDIX 1: NUMERICAL SIMULATION OF FULL FIELD MODEL

Data File of the Full Field SAGD Model

ROCKTYPE 1

PRPOR 2000
CPOR 14E-6 ** Effective formation (pore) compressibility (l/kPa)
rockcp 2.6e6 ** Rock heat capacity (J/m3-C)
thconr 6.6e5 ** Thermal conductivity of rock (J/m-day-C)
thconw 5.35e4 ** Thermal conductivity of water phase (J/m-day-C)
thcono 1.15e4 ** Thermal conductivity of oil phase (J/m-day-C)
thcong 5000 ** Thermal conductivity of gas phase (J/m-day-C)
thconmix complex
HLOSST 11
HLOSSTDIFF 0.1
HLOSSPROP OVERBUR 2.60e6 1.51e5
UNDERBUR 2.60e6 1.51e5
**DILATION *PBASE 1000. *PDILA 2536. *PPACT 500. CRD 3.1e-4 FR 0.15
*PORRATMAX 1.3

thtype con 1 ** matrix
** ============== FLUID DEFINITIONS ==============
** Model and number of components
MODEL 3 3 3 1
** COMPONENT TYPES AND NAMES
COMPNAME 'WATER' 'BITUMEN' 'CH4'
** ------ ------ ------
**molecular mass[kg/gmol]
CMM
0.018 0.570 0.016
**critical pres.[kPa]
PCRIT
22048 1000 4600
**critical temp.[C]
TCRIT
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**ev=0.38 default
**surflash w o g
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**2nd coef. of gas/liq.K_value[1/kPa]
KV2
0 0 0
**3rd coef. of gas/liq.K_value[
KV3
0 0 0
**4th coef. of gas/liq.K_value[C]
KV4
0 0 -879.84
**5th coef. of gas/liq.K_value[C]
KV5
0 0 -265.99
** Reference conditions
PRSR 1000
TEMR 11
PSURF 101.3
TSURF 15.5
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   cap.[J/gmol-C]
**cpl2         0  3.7323  0.11872 **2nd coef. of liq heat
   cap.[J/gmol-C^2]
**cpl3         0 -2.646e-3 -8.416e-5 **3st coef. of liq heat
   cap.[J/gmol-C^3]
**1st coef. of gas heat cap.[J/gmol-C]
CPG1
0 -20 19.251
**2nd coef. of gas heat cap.[J/gmol-C^2]
CPG2
0 1.9 5.213e-2
**3st coef. of gas heat cap.[J/gmol-C^3]
CPG3
0 -1e-3 1.197e-5
**4th coef. of gas heat cap.[J/gmol-C^4]
CPG4
0 3e-7 -1.132e-8
**vaporization enthalpy correl [J/gmol-C]
HVR
0 1500. 1556.
**liquid mass density[kg/m3]
MASSDEN
0 999.3 320.4
**liquid compressibility[1/kPa]
CP
0 7e-7 1e-6
**thermal expansion coef.[1/C]
CT1
0 7e-4 8e-4
** liquid phases
**Temp       Water Bitumen(M&S)       CH4
VISCTABLE
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  10.0   0  1587284.565    98.0594
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  30.0   0  71948.73697    55.6444
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** ==================== RELATIVE PERMEABILITIES ==================== **
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** KRW     KROW

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SLT
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S1     krg     krog
0.35   0.8     0
0.3875 0.65918 0.00390625
0.425  0.535937 0.015625
0.4625 0.429102 0.0351563
0.5    0.3375  0.0625
0.5375 0.259961 0.0976563
0.575  0.195312 0.140625
0.6125 0.142383 0.191406
0.65   0.1     0.25
0.6875 0.0669922 0.316406
0.725  0.0421875 0.390625
0.7625 0.0244141 0.472656
0.8    0.0125  0.5625
0.8375 0.00527344 0.660156
0.875  0.0015625 0.765625
0.9125 0.000195312 0.878906
0.95   0     1

swr  0.15  ** irreducible water saturation
sgr  0.005  ** critical gas saturation
sorg 0.005

** end point
KRWIRO 0.1
KROCW  0.8

krtype con 1
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REDEPTH -280
TEMP CON 11

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MFRAC_OIL 'BITUMEN' CON 0.94

** Property: Oil Mole Fraction (CH4) Max: 0.06 Min: 0.06
MFRAC_OIL 'CH4' CON 0.06

** Property: Water Mole Fraction (WATER) Max: 1 Min: 1
MFRAC_WAT 'WATER' CON 1

** Property: Gas Mole Fraction (CH4) Max: 1 Min: 1
MFRAC_GAS 'CH4' CON 1

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** Property: Water Saturation Max: 0.997485 Min: 0.063162
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** ============== NUMERICAL CONTROL ==============**

*NUMERICAL
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CONVERGE TOTRES 0.001
UPSTREAM KLEVEL
NEWTONCYC 30
SDEGREE 1
MAXSTEPS 10000000

** ============== GEOMECHANIC MODEL ==============**

RUN

** ============== RECURRENT DATA ==============**

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DTWELL 0.01

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OPERATE MIN BHP 500. CONT
OPERATE MAX STL 300. CONT
**S rad geofac wfrac skin
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PERF GEO '106_05-24-083-07W4_0'
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  5 51 33 1. OPEN FLOW-TO 1
  4 51 33 1. OPEN FLOW-TO 2
  3 51 33 1. OPEN FLOW-TO 3
  2 51 33 1. OPEN FLOW-TO 4

SHUTIN '106_05-24-083-07W4_0'

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QUAL 0.8
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OPERATE MAX BHP 2200. CONT
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  4 51 30 1. OPEN FLOW-FROM 2
  3 51 30 1. OPEN FLOW-FROM 3
  2 51 30 1. OPEN FLOW-FROM 4

SHUTIN '107_05-24-083-07W4_0'

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PRODUCER 'INJ-CIRC'
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PERF GEO 'INJ-CIRC'
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  4 51 30 1. OPEN FLOW-TO 2
  3 51 30 1. OPEN FLOW-TO 3
  2 51 30 1. OPEN FLOW-TO 4

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PRODUCER 'PROD-CIRC'
OPERATE MIN BHP 1500. CONT
**S rad geofac wfrac skin
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PERF GEO 'PROD-CIRC'
**$ UBA      ff Status Connection
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2 51 33 1. OPEN FLOW-TO 4

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          2:6 51 33 5E+010
TMPSET *IJK 2:6 51 30 212
          2:6 51 33 212

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DATE 1997 10 1
DATE 1997 11 1

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          2:6 51 30 0
TMPSET *IJK 2:6 51 30 11
          2:6 51 33 11

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DATE 1998 1 1.00000
APPENDIX 2: NUMERICAL SIMULATION OF FULL FIELD MODEL

Data File of the Full Field ES-SAGD Model

ROCKTYPE 1
PRPOR 2000
CPOR 14E-6 ** Effective formation (pore) compressibility (1/kPa)
rockcp 2.6e6 ** Rock heat capacity (J/m3-C)
thconr 6.6e5 ** Thermal conductivity of rock (J/m-day-C)
thconw 5.35e4 ** Thermal conductivity of water phase (J/m-day-C)
thcono 1.15e4 ** Thermal conductivity of oil phase (J/m-day-C)
thcong 5000 * Thermal conductivity of gas phase (J/m-day-C)
thconmix complex
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*PORRATMAX 1.3
PERMCK 0.2

thtype con 1 ** matrix

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** MFRAC_OIL 'IC4toNC5' CON 1.3326E-01
** MFRAC_OIL 'C6 toC8' CON 6.2120E-02
** MFRAC_OIL 'C9 toC11' CON 4.6200E-03
** MFRAC_OIL 'Heavy' CON 7.3414E-01
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***
** THE FOLLOWING SECTION CAN BE USED FOR THE COMPONENT PROPERTY INPUT INTO
STARS
******************************************************************************
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**S Model and number of components
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COMPNAME 'WATER' 'C1' 'IC4toNC5' 'C6 toC8' 'C9 toC11' 'Heavy'
**
        ------ ------ ------ ------ ------ ------
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PCRIT
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TCRIT
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** low/high pressure; low/high temperature
** Pressure, kPa**

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** Gas-liquid K Value tables **

KVTABLE 'C1'

<table>
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<th>6.0000E+02</th>
<th>1.1000E+03</th>
<th>1.6000E+03</th>
<th>2.1000E+03</th>
<th>2.6000E+03</th>
<th>3.1000E+03</th>
<th>3.6000E+03</th>
<th>4.1000E+03</th>
<th>4.6000E+03</th>
<th>5.1000E+03</th>
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<tbody>
<tr>
<td>1.0000E+02</td>
<td>6.0000E+02</td>
<td>1.1000E+03</td>
<td>1.6000E+03</td>
<td>2.1000E+03</td>
<td>2.6000E+03</td>
<td>3.1000E+03</td>
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** Pressure, kPa**
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<th>Gas-liquid K Value tables</th>
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** T, deg C  1.0000E+02  6.0000E+02  1.1000E+03  1.6000E+03  2.1000E+03  2.6000E+03  3.1000E+03  3.6000E+03  4.1000E+03  4.6000E+03  5.1000E+03  5.6000E+03  6.1000E+03  6.6000E+03  7.1000E+03

** Gas-liquid K Value tables

** Pressure, kPa

** T, deg C  1.0000E+02  6.0000E+02  1.1000E+03  1.6000E+03  2.1000E+03  2.6000E+03  3.1000E+03  3.6000E+03  4.1000E+03  4.6000E+03  5.1000E+03  5.6000E+03  6.1000E+03  6.6000E+03  7.1000E+03
** $ Gas-liquid K Value tables 
KVTABLE 'C6 toC8'
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<tr>
<td>T, deg C</td>
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<td>6.0000E+02</td>
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<td>1.6000E+03</td>
<td>2.1000E+03</td>
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<tr>
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<td>------------</td>
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<td>6.6000E+03</td>
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| KVTABLE 'C9 toC11' | **$ |
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| 0.00024597 | 0.00026412 | 0.00028936 | 0.00032197 | 0.00036269 | 0.00041262 |
| 0.00047325 | 0.00054643 | 0.00063443 |
| 0.037271 | 0.0072919 | 0.004612 | 0.003671 | 0.003236 | 0.0030223 |
| 0.0029296 | 0.0029139 | 0.0029536 | 0.0030372 | 0.0031583 | 0.0033137 |
| 0.003502 | 0.0037228 | 0.003977 |
| 0.2773 | 0.053699 | 0.03294 | 0.025267 | 0.021417 | 0.019213 |
| 0.017878 | 0.017063 | 0.01659 | 0.016361 | 0.016314 | 0.016412 |
| 0.01663 | 0.01695 | 0.017361 |
| 1.1779 | 0.22497 | 0.1369 | 0.10338 | 0.085892 | 0.075362 |
| 0.0685 | 0.063819 | 0.060547 | 0.058246 | 0.056646 | 0.055574 |
| 0.054914 | 0.054583 | 0.054523 |
| 3.4407 | 0.64305 | 0.38774 | 0.29082 | 0.23947 | 0.20777 |
| 0.18645 | 0.1713 | 0.16015 | 0.15174 | 0.14529 | 0.14032 |
| 0.13646 | 0.13349 | 0.13122 |
| 7.7339 | 1.4153 | 0.8412 | 0.62523 | 0.51128 | 0.4406 |
| 0.39245 | 0.35765 | 0.33144 | 0.31113 | 0.29504 | 0.2821 |
| 0.27156 | 0.2629 | 0.25575 |
| 14.363 | 2.5827 | 1.5132 | 1.1122 | 0.90181 | 0.77177 |
| 0.6832 | 0.6189 | 0.57012 | 0.53188 | 0.50119 | 0.47608 |
| 0.45524 | 0.43773 | 0.42288 |
| 23.097 | 4.0963 | 2.371 | 1.7247 | 1.3862 | 1.1776 |
| 1.036 | 0.93328 | 0.85533 | 0.7941 | 0.74473 | 0.70411 | 0.67015 | 0.64136 | 0.6167 |
**Comparison of WinProp (W) and STARS K-value (S) phase split calculations**

|----------|--------------|--------------|--------------|--------------|--------------|--------------|

**A = Aqueous, L = Liquid, V = Vapor**

<table>
<thead>
<tr>
<th>Pressure, kPa</th>
<th>1.0000E+02</th>
<th>6.0000E+02</th>
<th>1.1000E+03</th>
<th>1.6000E+03</th>
<th>2.1000E+03</th>
<th>2.6000E+03</th>
<th>3.1000E+03</th>
<th>3.6000E+03</th>
<th>4.1000E+03</th>
<th>4.6000E+03</th>
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<th>5.6000E+03</th>
<th>6.1000E+03</th>
<th>6.6000E+03</th>
<th>7.1000E+03</th>
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** Gas-liquid *K* Value tables

KVTABLE 'Heavy'

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1e-006 1e-006 1e-006 1e-006 1e-006 1e-006 1e-006 1e-006 1e-006
1e-006 1e-006 1e-006 1e-006 1e-006 1e-006 1e-006 1e-006 1e-006
1e-006 1e-006 1e-006 1e-006 1e-006 1e-006 1e-006 1e-006 1e-006
1e-006 1e-006 1e-006 1e-006 1e-006 1e-006 1e-006 1e-006 1e-006
1e-006 1e-006 1e-006 1e-006 1e-006 1e-006 1e-006 1e-006 1e-006
```

**$ Gas-liquid K Value tables

KVTABLE 'Heavy'

```plaintext
1e-006 1e-006 1e-006 1e-006 1e-006 1e-006 1e-006 1e-006 1e-006
1e-006 1e-006 1e-006 1e-006 1e-006 1e-006 1e-006 1e-006 1e-006
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<td>** reference pressure, corresponding to the density</td>
<td>PRSR 3200</td>
<td>** reference temperature, corresponding to the density</td>
<td>TEMR 12</td>
<td>** pressure at surface, for reporting well rates, etc.</td>
<td>PSURF 101.325</td>
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<tr>
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<td>K_SURF 'IC4toNC5' 2.0763</td>
<td>K_SURF 'C6 toC8' 0.10125</td>
<td>K_SURF 'C9 toC11' 0.0029822</td>
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** reference pressure, corresponding to the density

** reference temperature, corresponding to the density

** pressure at surface, for reporting well rates, etc.

** temperature at surface, for reporting well rates, etc.

** Surface conditions

SURFLASH KVALUE
K_SURF 'C1' 332.89
K_SURF 'IC4toNC5' 2.0763
K_SURF 'C6 toC8' 0.10125
K_SURF 'C9 toC11' 0.0029822
K_SURF 'Heavy' 3.5814e-020
MOLDEN
0 21820 10380 7556 5829 1687
CP
0 3.696e-006 1.621e-006 1.128e-006 8.51e-007 2.295e-007
CT1
0 0.001438 0.0002575 0.0001185 6.347e-005 2.346e-005
CT2
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<th>WATER</th>
<th>C1</th>
<th>IC4toNC5</th>
<th>C6 toC8</th>
<th>C9 toC11</th>
<th>Heavy</th>
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**VISCTABLE**

*ATPRES 100*

**$**

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*ATPRES 1975*

**$**

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*ATPRES 3850*

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** The following is the complete WinProp fluid model description.

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WINPROP *TITLE1     'solvent characterization'
WINPROP *TITLE2     ''
WINPROP *TITLE3     ''
WINPROP *INUNIT     *SI
WINPROP *MODEL      *PR   *1978
WINPROP *NC         5      5
WINPROP *PVC3       1.8000000E+00
WINPROP *COMPNAME   'C1      ' 'IC4toNC5' 'C6 toC8 ' 'C9 toC11' 'Heavy   '
WINPROP *HCFLAG     1  1  1  1  1
WINPROP *SG         3.0000000E-01 6.0235437E-01 7.2332397E-01 7.8167598E-01 1.0120000E+00
WINPROP *TB         -1.6145000E+02 1.5740789E+01 9.3278245E+01 1.6638434E+02 6.2020100E+02
WINPROP *PCRIT      4.5400000E+01 3.5036936E+01 3.0829515E+01 2.4975607E+01 9.2747301E+00
WINPROP *VCRIT      9.9000000E-02 2.8168118E-01 3.8156827E-01 5.2143457E-01 1.6901000E+00
WINPROP *TCRIT      1.9060000E+02 4.4141744E+02 5.4115068E+02 6.2200593E+02 1.0667815E+03
WINPROP *AC         8.0000000E-03 2.1175000E-01 3.1155600E-01 4.3734567E-01 1.2489970E+00
WINPROP *MW         1.6043000E+01 6.5137500E+01 9.6333333E+01 1.3400000E+02 6.0000000E+02
WINPROP *VSHIFT     0.0000000E+00 2.9994847E-02 -2.1376906E-02 3.2474812E-02 2.1683250E-01
WINPROP *ZRA        2.8760000E-01 2.7197500E-01 2.6737163E-01 2.5955053E-01 2.3560053E-01
WINPROP *VISVC      9.9000000E-02 2.8200000E-01 3.8200000E-01 5.2200000E-01 1.6901000E+00
WINPROP *VISCOR     *MODPEDERSEN
WINPROP *VISCOEFF   *OMEGA
WINPROP 1.3040000E+00 5.9024000E-01 2.1175000E-01 2.3030000E+00 4.6225778E-01
WINPROP 4.5723553E-01 4.5723553E-01 4.5723553E-01 4.5723553E-01 4.5723553E-01
WINPROP *OMEGAB
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WINPROP  7.796074E-02  7.796074E-02  7.796074E-02  7.796074E-02
WINPROP *PCHOR
WINPROP  7.7000000E+01  2.0697500E+02  2.7916667E+02  3.8166667E+02
WINPROP *ENTHALPY
WINPROP  7.7000000E+01  2.0697500E+02  2.7916667E+02  3.8166667E+02
WINPROP *COMPOSITION *PRIMARY
WINPROP  8.2330000E-02  0.0000000E+00  0.0000000E+00  9.1767000E-01
WINPROP *COMPOSITION *SECOND
WINPROP   0.0000000E+00  6.6630000E-01  3.1060000E-01  2.3100000E-02
** ======== RELATIVE PERMEABILITIES ============== **
rockfluid
** --------- good zone -----------
RPT 1 STONE2 WATWET
** KRW    KROW
*INCLUDE 'swt_krw 25_krow 25.inc'
** KRG    KROG     PCG
SLT
**$   S1   krg    krogs
   0.35   0.8      0
   0.3875  0.6918   0.00390625
   0.425   0.535937  0.015625
   0.4625  0.429102  0.0351563
   0.5     0.3375   0.0625
   0.5375  0.259961  0.0976563
   0.575   0.195312  0.140625
   0.6125  0.142383  0.191406
   0.65    0.1      0.25
   0.6875  0.0669922 0.316406
   0.725   0.0421875 0.390625
   0.7625  0.0244141 0.472656
   0.8     0.0125   0.5625
   0.8375  0.00527344 0.660156
   0.875   0.0015625 0.765625
   0.9125  0.000195312 0.878906
   0.95    0       1
swr   0.15     ** irreducible water saturation
sgr   0.005    ** critical gas saturation
sorg  0.005
** end point
KRWIRO 0.1
KROCW 0.8

krtype con 1

** ============== INITIAL CONDITIONS ==============
INITIAL
VERTICAL_DEPTH_AVE

REFPRES 1000

REFDEPTH -280
TEMP CON 11

** Property: Gas Mole Fraction(WATER)  Max: 0  Min: 0
MFRAC_GAS 'WATER' CON 0

** Property: Water Mole Fraction(WATER)  Max: 1  Min: 1
MFRAC_WAT 'WATER' CON 1

** Property: Oil Mole Fraction(C1)  Max: 0.065864  Min: 0.065864
MFRAC_OIL 'C1' CON 0.065864

** Property: Oil Mole Fraction(C9 toC11)  Max: 0.00462  Min: 0.00462
MFRAC_OIL 'C9 toC11' CON 0.00462

** Property: Oil Mole Fraction(Heavy)  Max: 0.73414  Min: 0.73414
MFRAC_OIL 'Heavy' CON 0.73414

** Property: Oil Mole Fraction(IC4toNC5)  Max: 0.13326  Min: 0.13326
MFRAC_OIL 'IC4toNC5' CON 0.13326

** Property: Oil Mole Fraction(C6 toC8)  Max: 0.06212  Min: 0.06212
MFRAC_OIL 'C6 toC8' CON 0.06212

** Property: Gas Saturation  Max: 0.85  Min: 0
SG KVAR 2*0.85 38*0

** Property: Water Saturation  Max: 0.997485  Min: 0.063162
SW ALL 1224*0.15 0.928104 0.975192 0.955561 0.947585 0.935387 0.905168

** ============== NUMERICAL CONTROL ==============

*NUMERICAL
MATBALTOL 0.1
CONVERGE TOTRES 0.001
UPSTREAM KLEVEL
NEWTONCYC 30
SDEGREE 1
MAXSTEPS 10000000

** ============== GEOMECHANIC MODEL ==============
** RECURRENT DATA ============
DATE 1997 8 1
DTWELL 0.01

**$ WELL '106_05-24-083-07W4_0'
PRODUCER '106_05-24-083-07W4_0'
OPERATE MIN STEAMTRAP 10. CONT
OPERATE MIN BHP 500. CONT
OPERATE MAX STL 300. CONT
**$ rad geofac wfrac skin
GEOMETRY I 0.086 0.249 1. 0.
PERF GEO '106_05-24-083-07W4_0'
**$ UBA ff Status Connection
  6 51 33 1. OPEN FLOW-TO 'SURFACE' REFLAYER
  5 51 33 1. OPEN FLOW-TO 1
  4 51 33 1. OPEN FLOW-TO 2
  3 51 33 1. OPEN FLOW-TO 3
  2 51 33 1. OPEN FLOW-TO 4

SHUTIN '106_05-24-083-07W4_0'

**$
WELL '107_05-24-083-07W4_0'
INJECTOR MOBWEIGHT IMPLICIT '107_05-24-083-07W4_0'
INCOMP WATER-GAS-OIL 0.8659 0. 0.0818 0.0474 0.0049 0.
TINJW .212.
QUAL 0.8
OPERATE MAX STF 300. CONT
OPERATE MAX BHP 2200. CONT
**$ rad geofac wfrac skin
GEOMETRY I 0.086 0.249 1. 0.
PERF GEO '107_05-24-083-07W4_0'
**$ UBA ff Status Connection
  6 51 30 1. OPEN FLOW-FROM 'SURFACE' REFLAYER
  5 51 30 1. OPEN FLOW-FROM 1
  4 51 30 1. OPEN FLOW-FROM 2
  3 51 30 1. OPEN FLOW-FROM 3
  2 51 30 1. OPEN FLOW-FROM 4

SHUTIN '107_05-24-083-07W4_0'

**$
WELL 'INJ-CIRC'
PRODUCER 'INJ-CIRC'
OPERATE MIN BHP 1500. CONT
**$ rad geofac wfrac skin
GEOMETRY I 0.086 0.249 1. 0.
PERF GEO 'INJ-CIRC'
**$ UBA ff Status Connection
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**UHTR *IJK 2:6 51 30 5E+010**

**TMPSET *IJK 2:6 51 30 212**

*******************************START SAGD*****************************

DATE 1997 9 1
DATE 1997 10 1
DATE 1997 11 1

*******************************START SAGD*****************************

DATE 1997 9 1
DATE 1997 10 1
DATE 1997 11 1

******************************START SAGD*****************************

DATE 1997 9 1
DATE 1997 10 1
DATE 1997 11 1

******************************START SAGD*****************************

DATE 1997 9 1
DATE 1997 10 1
DATE 1997 11 1

******************************START SAGD*****************************

DATE 1997 9 1
DATE 1997 10 1
DATE 1997 11 1

******************************START SAGD*****************************

DATE 1997 9 1
DATE 1997 10 1
DATE 1997 11 1

******************************START SAGD*****************************

DATE 1997 9 1
DATE 1997 10 1
DATE 1997 11 1
APPENDIX 3: NUMERICAL SIMULATION OF FULL FIELD MODEL

Data File of the Full Field Reservoir Geomechanics Model

ROCKTYPE 1
PRPOR 2000
CPOR 14E-6  ** Effective formation (pore) compressibility (1/kPa)

rockcp 2.6e6  ** Rock heat capacity (J/m3-C)
thconr 6.6e5  ** Thermal conductivity of rock (J/m-day-C)
thconw 5.35e4  ** Thermal conductivity of water phase (J/m-day-C)
thcono 1.15e4  ** Thermal conductivity of oil phase (J/m-day-C)
thcong 5000  ** Thermal conductivity of gas phase (J/m-day-C)
thconmix complex
HLOSST 11
HLOSSTDIFF 0.1
HLOSSPROP OVERBUR 2.60e6 1.51e5
UNDBUR 2.60e6 1.51e5

thtype con 1  ** matrix
** ============== FLUID DEFINITIONS ==============
**$ Model and number of components
MODEL 3 3 3 1
** COMPONENT TYPES AND NAMES
COMPNAME 'WATER' 'BITUMEN' 'CH4'
** ------ ------- -------
**molecular mass[kg/gmol]
CMM
0.018 0.570 0.016
**critical pres.[kPa]
PCRIT
22048 1000 4600
**critical temp.[C]
TCRIT
374.2 703.9 -82.6
**ev=0.38 default
**surfflash w o g
** K-VALUE CORRELATION DATA
**1st coef.of gas/liq.K_value[kPa]
KV1
0 0 5.4547e5
**2nd coef.of gas/liq.K_value[1/kPa]
KV2
0 0 0
**3rd coef.of gas/liq.K_value[]
KV3
0 0 0
**4th coef.of gas/liq.K_value[C]
KV4
0 0 -879.84
**5th coef.of gas/liq.K_value[C]
KV5
0 0 -265.99
** Reference conditions
PRSR 1000
TEMR 11
PSURF 101.3
TSURF 15.5
**cpl1         0 -3.521    -0.112    **1st coef. of liq heat cap.[J/gmol-C]
**cpl2         0  3.7323   0.11872    **2nd coef. of liq heat cap.[J/gmol-C^2]
**cpl3         0 -2.646e-3 -8.416e-5    **3st coef. of liq heat cap.[J/gmol-C^3]
**1st coef. of gas heat cap.[J/gmol-C]
CPG1
0 -20 19.251
**2nd coef. of gas heat cap.[J/gmol-C^2]
CPG2
0  1.9 5.213e-2
**3st coef. of gas heat cap.[J/gmol-C^3]
CPG3
0 -1e-3 1.197e-5
**4th coef. of gas heat cap.[J/gmol-C^4]
CPG4
0 3e-7 -1.132e-8
**vaporization enthalpy correl [J/gmol-C]
HVR
0 1500. 1556.
**liquid mass density[kg/m3]
MASSDEN
0 999.3 320.4
**liquid compressibility[1/kPa]
CP
0 7e-7 1e-6
**thermal expansion coef.[1/C]
CT1
0 7e-4 8e-4
** liquid phases
**Temp Water Bitumen(M&S) CH4
VISCTABLE
**$ 
 temp 5.0   0  4062963.508  115.0417
 10.0  0  1587284.565  98.0594
 20.0  0  299536.7897  72.8797
 30.0  0  71948.73697  55.6444
 40.0  0  21109.25852  43.4958
 50.0  0  7318.084918  34.7074
 60.0  0  2918.288507  28.2014
 70.0  0  1309.633630  23.2847
 80.0  0  649.6127524  19.5001
 90.0  0  350.9125047  16.5380
100.0  0  203.9087620  14.1848
110.0  0  126.1554325  12.2898
120.0  0  82.38935262  10.7449
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** ============== RELATIVE PERMEABILITIES ============== **

rockfluid
** ============ good zone ===========
RPT 1 STONE2 WATWET
** KRW    KROW

*INCLUDE 'swt_krw 25_krow 25.inc'

** KRG KROG PCG
SLT
**$

\[
\begin{array}{ccc}
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0.575 & 0.195312 & 0.140625 \\
0.6125 & 0.142383 & 0.191406 \\
0.65 & 0.1 & 0.25 \\
0.6875 & 0.0669922 & 0.316406 \\
0.725 & 0.0421875 & 0.390625 \\
0.7625 & 0.0244141 & 0.472656 \\
0.8 & 0.0125 & 0.5625 \\
0.8375 & 0.00527344 & 0.660156 \\
0.875 & 0.0015625 & 0.765625 \\
0.9125 & 0.000195312 & 0.878906 \\
0.95 & 0 & 1
\end{array}
\]

swr 0.15  ** irreducible water saturation
sgr 0.005  ** critical gas saturation
sorg 0.005

** end point
KRWO 0.1
KROCW 0.8

krtype con 1
** ================ INITIAL CONDITIONS ================**
INITIAL
VERTICAL DEPTH_AVE

REFPRES 1000

REFDEPTH -280
TEMP CON 11

** Property: Oil Mole Fraction (BITUMEN) Max: 0.94 Min: 0.94
MFRAC_OIL 'BITUMEN' CON 0.94

** Property: Oil Mole Fraction (CH4) Max: 0.06 Min: 0.06
MFRAC_OIL 'CH4' CON 0.06

** Property: Water Mole Fraction (WATER) Max: 1 Min: 1
MFRAC_WAT 'WATER' CON 1

** Property: Gas Mole Fraction (CH4) Max: 1 Min: 1
MFRAC_GAS 'CH4' CON 1

** Property: Gas Saturation Max: 0.85 Min: 0
SG KVAR
2*0.85 38*0

** Property: Water Saturation Max: 0.997485 Min: 0.063162
SW ALL
1224*0.15 0.928104 0.826841 0.975192 0.955561 0.947585 0.935387 0.905168

** ================ NUMERICAL CONTROL ================**

*NUMERICAL
NUMERICAL
MATBALTOL 0.1
CONVERGE TOTRES 0.001
UPSTREAM KLEVEL
NEWTONCYC 30
SDEGREE 1
MAXSTEPS 1000000

** ================ GEOMECHANIC MODEL ================**

*GEOMECH ** Main keyword for using geomechanics module
*GEOM3D ** Using 3D finite elements

**GEOSGRID *GCART 10 122 56
**GDI *GJVAR 2*100 6*70 2*100
**GDJ *GJVAR 5*10 5*4 102*2 5*4 5*10
**GDK *GKVAR 1*100 2*50 3*20 5*10 5*4 40*2
**GTRANSLI -200
**GTRANSLJ -70
**GTRANSLK 48
**GEODEPTH 1 1 1 -610
*STRESS3D 5600 5600 5600 0 0 0
*STRESSGRAD3D -20 -20 -20 0 0 0

*SOLVERG *AIMSOL
*GPTOLMUL 0.1
*gcoupling 2 ** Type # 2 coupling with STARS
*GOUTSRF *GGRID *ALL

NITERGEO 500

GEOROCK 1
NLINEAR 2
** unitless
ECOEF 448.33
** unitless
BCOEF 742.22
** ambient pressure (kpa)
GPATM 101.325
** fraction ratio (unitless)
FRATIO 0.85
** unitless
NE 0.8822
** unitless
NB 0.8822
** unitless
NTE 0
** unitless
NTB 0
** unitless
EXPN1 2.0
** unitless
EXPN2 1.0
** degrees
FRICANGMN 20
** degrees
FRICANGMX 55
** degrees
DFRICANGLE 20
** unit less
URECOEF 448.33
** unit less
URBCOEF 742.22
** unitless
URNE 0.5
** unitless
URNB 0.5
** unitless
URNTE 0
** unitless
URNTE 0
** unitless
UREXPNL 2.0
** unitless
UREXPNL 1.0
** kpa
COHESION 10
** degrees
FRICANGLE 40
** unitless
MCOEF 1.0
THEXPCOEF 2e-5

*GPERMLC 17.48 ** Empirical formula is used

RUN

** ==============================================================RECURRENT DATA ============
DATE 1997 8 1
DTWELL 0.01

**$ WELL '106_05-24-083-07W4_0'
PRODUCER '106_05-24-083-07W4_0'
OPERATE MIN STEAMTRAP 10. CONT
OPERATE MIN BHP 500. CONT
OPERATE MAX STL 300. CONT

**$ rad geofac wfrac skin
GEOMETRY I 0.086 0.249 1. 0.
PERF GEO '106_05-24-083-07W4_0'

**$ UBA ff Status Connection
  6 51 33 1. OPEN FLOW-TO 'SURFACE' REFLAYER
  5 51 33 1. OPEN FLOW-TO 1
  4 51 33 1. OPEN FLOW-TO 2
  3 51 33 1. OPEN FLOW-TO 3
  2 51 33 1. OPEN FLOW-TO 4

SHUTIN '106_05-24-083-07W4_0'

**$
WELL '107_05-24-083-07W4_0'
INJECTOR MOBWEIGHT EXPLICIT '107_05-24-083-07W4_0'
INCOMP WATER 1. 0. 0.
TINJW 212.
QUAL 0.8
OPERATE MAX STW 300. CONT
OPERATE MAX BHP 2200. CONT

**$ rad geofac wfrac skin
GEOMETRY I 0.086 0.249 1. 0.
PERF GEO '107_05-24-083-07W4_0'

**$ UBA ff Status Connection
  6 51 30 1. OPEN FLOW-FROM 'SURFACE' REFLAYER
  5 51 30 1. OPEN FLOW-FROM 1
  4 51 30 1. OPEN FLOW-FROM 2
  3 51 30 1. OPEN FLOW-FROM 3
  2 51 30 1. OPEN FLOW-FROM 4

SHUTIN '107_05-24-083-07W4_0'
**$ WELL 'INJ-CIRC'
PRODUCER 'INJ-CIRC'
OPERATE MIN BHP 1500. CONT
**$ rad geofac wfrac skin
GEOMETRY I 0.086 0.249 1. 0.
PERF GEO 'INJ-CIRC'
**$ UBA ff Status Connection
   6 51 30 1. OPEN FLOW-TO 'SURFACE' REFLAYER
   5 51 30 1. OPEN FLOW-TO 1
   4 51 30 1. OPEN FLOW-TO 2
   3 51 30 1. OPEN FLOW-TO 3
   2 51 30 1. OPEN FLOW-TO 4

**$ WELL 'PROD-CIRC'
PRODUCER 'PROD-CIRC'
OPERATE MIN BHP 1500. CONT
**$ rad geofac wfrac skin
GEOMETRY I 0.086 0.249 1. 0.
PERF GEO 'PROD-CIRC'
**$ UBA ff Status Connection
   6 51 33 1. OPEN FLOW-TO 'SURFACE' REFLAYER
   5 51 33 1. OPEN FLOW-TO 1
   4 51 33 1. OPEN FLOW-TO 2
   3 51 33 1. OPEN FLOW-TO 3
   2 51 33 1. OPEN FLOW-TO 4

UHTR *IJK 2:6 51 30 5E+010
        2:6 51 33 5E+010
TMPSET *IJK 2:6 51 30 212
         2:6 51 33 212

***********************************************************************
DATE 1997 9 1
DATE 1997 10 1
DATE 1997 11 1

***********************************************************************START SAGD
DTWELL 0.01
OPEN '107_05-24-083-07W4_0'
SHUTIN 'INJ-CIRC'
SHUTIN 'PROD-CIRC'
OPEN '106_05-24-083-07W4_0'

UHTR *IJK 2:6 51 33 0
        2:6 51 30 0
TMPSET *IJK 2:6 51 30 11
         2:6 51 33 11
ALTER '107_05-24-083-07W4_0'
79
DATE 1998 1 1.00000