AES/PE/10-20  Methane Production from Gas Hydrate Using Depressurization Method

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Depressurization Method

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Abstract

Gas hydrates are significant resource of natural gas existing both on-shore buried under the permafrost and off-shore buried under oceanic and deep lake sediments. Earlier studies have demonstrated that large volumes of gas can be produced from gas hydrate accumulations by means of depressurization-induced dissociation using vertical wells. In this study gas hydrate production from a class-3-hydrate reservoir is investigated, on how the production results change if a homogeneous or a heterogeneous reservoir is used for the simulations. The production is by means of a vertical well drilled at the edge of the reservoir. Additionally, it has been studied how the placement of a vertical well and the number of vertical wells and their spacing influences the production. Also the efficiency of producing from a single horizontal well is studied and compared to the results of simulations with vertical wells.

It was observed that the permeability of the reservoir has a strong impact on how the methane hydrates dissociate in the reservoir. Comparing the production data and how the reservoir has been swept of gas hydrates for the different scenarios employing various kind and amounts of well, it can be concluded that the scenario with two vertical wells is the most efficient scenario studied giving the most efficient production, low water production also because unwanted gravity segregation could be avoided.

Keywords: gas hydrates, gas production, multiple wells, horizontal wells.
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CHAPTER ONE

Methane Production from Gas-Hydrate

1.0 Introduction

The world civilization needs a constant supply of energy to survive. Conventional energy sources such as coal, oil, flowing water, wind, bio-resources and nuclear sources help us in meeting our energy demands. However, it is now realized that the energy resources on earth are being depleted and by the year 2050 these reserves will be almost exhausted. Hence, it is imperative for the world to search for non-conventional energy sources due to the increase in demand for energy\textsuperscript{12}. One of the alternative energy sources such as gas hydrates can be of great service to mankind in the future\textsuperscript{12}.

Although gas-hydrates were probably encountered by other scientists earlier, credit for their discovery normally goes to the prominent English chemist, Sir Humphrey Davy in the early 19\textsuperscript{th} century. In particular, he noted that the ice-like solid formed at temperatures greater than the freezing point of water, and that the solid was composed of more than just water. Michael Faraday also studied the hydrate of chlorine and some other scientists that never relented until date, tried to understand more about hydrates and its best recovery mechanism\textsuperscript{21}.

Throughout the 19\textsuperscript{th} century until date, hydrates had remained an intellectual curiosity. Early efforts focused on finding which compounds formed hydrates and under what temperatures and pressures they would form and how best to recover it\textsuperscript{21}.

This work strictly focuses on methane production from class 3-hydrate layer with absence of underlying zones of mobile fluids.

Thereby, it is investigated what the best scenario is to produce gas from gas hydrate bearing layers by the depressurization method. For this purpose simulations with CMG Stars are performed and the key parameters are identified.

Recent studies\textsuperscript{1,2,19} have indicated that under specific conditions, gas can be produced from natural gas hydrate deposits at high rates over long periods. Practically all of these
investigations involved vertical wells, but preliminary result from an early horizontal well study also indicates that production from a horizontal well from class-3- hydrate reservoir will be more attractive\textsuperscript{20}.

1.1 Objective

In this study the dissociation method applied is depressurization method in a reservoir consisting of class 3 hydrate layer with absence of underlying zones of mobile fluids. The goal of this study is to investigate how to optimize gas production from gas hydrate bearing layers using single, multiple vertical wells and a single horizontal well. This study considers two different reservoir models; Homogeneous reservoir model and heterogeneous reservoir model. Comparison will be made between performances of single, multiple vertical and horizontal production wells in a homogeneous reservoir. Furthermore, the performance of single well will be viewed in different heterogeneous models.

1.2 GAS-HYDRATES

Natural gas-hydrates are crystalline substances composed of water and gas in which a solid water-lattice accommodates gas molecules in a cage like structure as shown in the figure\textsuperscript{1.1}. Thus it is similar to ice, except that the crystalline structure is stabilized by the guest gas molecule within the cage of water molecules. Many gases have molecular sizes suitable to form gas-hydrate, including such naturally occurring gases as carbon dioxide, hydrogen sulphide, and several low-carbon number hydrocarbons, but most marine gas hydrates that have been analyzed are methane hydrates as mentioned earlier\textsuperscript{23}.
Methane is volumetrically compressed in a gas hydrate by a factor of 164 compared to its volume at standard conditions.

1.3 Hydrate Structure

Hydrates are formed due to the unusual behavior of water molecules and its orientation. Water molecules consist of one oxygen atom covalently bonded to two hydrogen atoms. The angle between the atoms is 104.5°. There are two unbonded electrons which induces partially negative charge on oxygen atom due to its high electronegativity relative to hydrogen atom. The partially induced charges result in one molecule link up with other water molecules in the form of bond which is called hydrogen bonds. When the water molecules line up they arrange themselves in different patterns. Hydrates are formed due to this ability of water to form hydrogen bonds. When hydrates are formed the guest molecules and the host molecules are held together by Van der Waals force. There is no bonding between the guest and the host molecules.

Hydrocarbon and water forms gas-hydrate at low temperatures and high pressures. It forms three different crystal structures (structure I, II, H) depending upon the size of the hydrocarbon. These three different crystal structures are formed by the combination of different basic cavities. The basic cavities of hydrate structures are labeled as n^m where n is the number of edges and m is the number of faces.
Pentagonal dodecahedron ($5^{12}$) has 12 pentagonal faces with equal edge length and angles. Tetrakaidecahedron ($5^{12} 6^2$) has 12 pentagonal faces and two hexagonal faces. There are also different other cavities like the irregular dodecahedron ($4^3 5^6 6^3$) shown also in the figure 1.2 below.

Fig1.2 Gas hydrate structures\textsuperscript{24}
Structure I
This structure was first observed for ethylene oxide hydrate in 1965 by McMullan and Jeffrey. It is a base centered cubic structure with lattice constant of 12 Å, formed by smaller guest molecules like CH₄, C₂H₆, CO₂ and H₂S. There are 46 water molecules arranged to accommodate 8 guest molecules of size 4-6 Å in diameter. There are two small cages of pentagonal dodecahedron and six tetrakaidecahedron. Structural composition is 8G.46H₂O where G is the guest molecules as explained earlier.

Structure II
This structure was observed by McMullan and Jeffery for a H₂S hydrate in 1965. It is a face centered cubic structure which can accommodate 24 guest molecules. It has 16 small and 8 large cages with 136 water molecules per unit cell. Hydrate with guest molecules like propane, Iso-butane usually form this structure. Lattice constant is 17.3 Å. Structural composition is 24G.136H₂O²⁵.

Structure H
It was first identified by Ripmeester²⁶ in 1987. These crystals have large volume capacity and can accommodate big molecules like n-butane which has a diameter of 7.1 Å. Structure H is composed of three different types of cavities. It contains 34 water molecules associated with three 5₁₂ cavity guest molecules, two 4₅₆₃ cavity guest molecule and one 5₁₂₂ cavity guest molecules. Smaller guest molecules, such as CH₄, N₂ and CO₂ occupy 5₁₂ cavities, and large guest molecules such as 2-methylbutane, methylcyclopentane, methylcyclohexane, ethylcyclohexane and cyclooctane occupy 4₅₆₃ cavities²⁶.

1.4 Occurrence of Gas-Hydrate

The geologic occurrence of gas-hydrates has been known since mid-1960s when gas hydrate accumulations were discovered in Russia. Natural gas-hydrates can be found in the deep marine sediments and permafrost, were the thermodynamic conditions of low temperature and high pressure allow gas-hydrate formation. Gas-hydrates are located in areas like North Slope of Alaska and Canada and as well as in offshore continental marine environments throughout the world including the Gulf of Mexico and the East and West Coast of the United States.
Figure 1.3 below shows different locations of gas-hydrate in the world\textsuperscript{21}.

![Map showing locations of known and inferred gas hydrate occurrences\textsuperscript{21}](image)

**1.5 Phase-Diagram**

As already mentioned, gas hydrates are formed at low temperatures and high pressure. With the help of so-called phase diagrams the regions in which hydrates are stable can be identified. In figure 1.4 a typical phase diagram of water + gas is given. The line describes the phase equilibrium line. At pressures higher than the equilibrium pressures hydrates are stable. At pressures lower than the equilibrium pressure, no gas hydrates exist. The phase diagram changes depending on the gas\textsuperscript{21}.
1.6 The Hydrate Pressure-Temperature Stability Envelope

Hydrates are formed at conditions of low temperature and high pressure as explained in figure 1.5. Figure a. and b. shows the hydrate stability zone both in permafrost and in oceanic sediments. The overlap of the phase boundary and temperature gradient indicates the extent of the gas hydrate stability zone (GHSZ). Gas hydrates are stable on ocean floor sediments at a depth of roughly 400 meters and in permafrost regions of depth approximately 200 meters. These figures are based upon hydrates which are formed by methane. If we consider other heavy natural gases like propane, iso-butane we can observe an increase in the depth of the hydrate stability zone due to the shift of the phase boundary line.
1.7 Classification of hydrate deposits and production methods

Classification of Hydrate Deposits

Natural hydrate accumulations are divided into three main classes:

Class I—the class I accumulations are composed of two layers; the hydrate interval and an underlying two-phase-fluid zone with free (mobile) gas.

Class II — this consists of a hydrate bearing layer underlain by a one-phase layer of mobile water.

Class III — the class III accumulations are composed of a single zone, the hydrate layer with absence of underlying zones of mobile fluids.

Production methods:

There are three main methods of hydrate dissociation:

(a) Depressurization: In this method, a production well is drilled into the hydrate reservoir and a pressure difference is created between the wellbore and adjacent blocks. Pressure reduction frees the methane molecules from hydrate.
(b) Thermal stimulation method: In this technique heat is added to the reservoir at constant pressure. When the heat is added by, e.g., circulating hot fluids downhole, the temperature increases until the hydrate dissociation temperature is reached.

(c) Inhibitor injection method: In this method, injection of inhibitors (e.g. Salts, methanol, and e.t.c) shifts the pressure-temperature equilibrium leading to rapid dissociation of gas hydrate.

Figure 1.6 The three common means of hydrate dissociation\textsuperscript{21}. 
CHAPTER TWO
Component description and Equations

CMG (STAR) Simulator:

STARS (Steam Thermal and Advanced Processes Reservoir simulator) is a new generation reservoir simulator developed by Computer Modeling Group Limited for modeling the flow of three phases, multi-component fluids.

STARS can be used to model compositional, steam, geo mechanical, dispersed component (polymer, gels, fines, emulsions, and foams) and in-situ combustion process. STARS uses a discretized wellbore model which improves modeling by discretizing the wellbore and solving the resulting coupled wellbore and reservoir flow problem simultaneously.

The adaptive implicit mode in STARS decides from time-step to time-step which blocks must be solved in implicit or explicit modes. Chemical reactions between components can also be specified with fixed rate dependence.

The governing equations used in this simulation work are given below, with the necessary plots for better understanding.

Component description:

A three component kinetic model was developed to simulate hydrate decomposition and formation in a geological reservoir. The components are water (H₂O) present in the aqueous liquid and gas phase, methane (CH₄) only present as gas, and CH₄ gas hydrates (CH₄.nH₂O) forming part of the solid phase. The component basic properties such as molecular mass, molar density, critical pressure and temperature were obtained from the literature and the CMG (STARS) input manual.
Component properties are shown table 1 below:

<table>
<thead>
<tr>
<th>Components</th>
<th>Water</th>
<th>Methane</th>
<th>Methane-Hydrate</th>
<th>Units</th>
</tr>
</thead>
<tbody>
<tr>
<td>Molecular weight</td>
<td>18.016</td>
<td>16.043</td>
<td>119.543</td>
<td>Kg/mole</td>
</tr>
<tr>
<td>Critical pressure</td>
<td>22048</td>
<td>4600</td>
<td>—</td>
<td>KPa</td>
</tr>
<tr>
<td>Critical temperature</td>
<td>647.15</td>
<td>190.45</td>
<td>—</td>
<td>K</td>
</tr>
<tr>
<td>Compressibility</td>
<td>3.0E-06</td>
<td>—</td>
<td>—</td>
<td>1/KPa</td>
</tr>
<tr>
<td>First thermal expansion coefficient</td>
<td>1.2E-04</td>
<td>—</td>
<td>—</td>
<td>1/C</td>
</tr>
<tr>
<td>Density</td>
<td>999.9</td>
<td>—</td>
<td>919.7</td>
<td>Kg/m³</td>
</tr>
</tbody>
</table>

**Porosity**

Porosity ($\phi$) describes the fraction of void space in a material, where the material may contain, for example air, water, hydrocarbon, e.t.c. It is also a fraction of the volume of void spaces over the total rock volume, between 0 to 1, or as a percentage between 0 to 100 percent (%). It shows the storage capacity of a rock or a material.

Total porosity is a measure of total void space to bulk volume of a rock, whereas effective porosity refers to void space contributing to flow of fluids (commonly determined in the Lab.). Rock types are classified into; (a) Unconsolidated rocks: rocks that appear in the form of loose particles such as sand (range of porosity is 0.2 to 0.5) and gravel (range of porosity is 0.2 to 0.4). (b) Consolidated rocks: They are tightly bound rocks composed of sandstone (porosity range is 0.05 to 0.3), shale (porosity range is 0 to 0.1).
In CMG STARS, hydrate is modeled as a solid matrix. As a consequence the porosity changes with the hydrate occurrence or in other words with the hydrate saturation. If there is no hydrate present, then the porosity is the porosity of the given matrix. This is defined mathematically as:

$$\phi = \phi_0 \left(1 - S_h\right)$$

Where; $\phi$ is the porosity dependent on hydrate saturation and is called effective porosity $\phi_0$; This is the initial or absolute porosity.

$S_h$; Hydrate-saturation.

Figures 2.1 shows the dependence of the porosity on hydrate saturation.

Relative Permeability and capillary pressure

The relative permeability and capillary pressure data were obtained from analytical functions suggested by van Genuchten and Parker et al. A change in relative permeability is described using
Stone’s Three-Phase Model II. The input parameters for these two functions are listed in Table 2 below.

Table 2 Relative permeability and capillary pressure input values.

<table>
<thead>
<tr>
<th>Relative permeability and Capillary pressure input values</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Residual water saturation</td>
<td>0.2</td>
</tr>
<tr>
<td>Residual gas saturation</td>
<td>0.02</td>
</tr>
<tr>
<td>Permeability reduction exponent</td>
<td>3</td>
</tr>
<tr>
<td>Saturated water saturation</td>
<td>1</td>
</tr>
</tbody>
</table>

**Permeability in presence of hydrates:**

For the simulation of gas hydrate production with CMG Stars it is accounted for the fact that the absolute permeability (and relative permeability) changes with the presence of hydrates.

One of the vital parameters in modeling hydrate formation and dissociation in porous media is the permeability variation in the presence of hydrates. As the hydrate grows in the pore spaces, it reduces the porosity of the rock, and also the permeability of the rock.

If no hydrates are present, the absolute permeability becomes the absolute permeability of the rock.

In this simulation the reservoir absolute permeability was modified at each time-step as a function of hydrate formation or decomposition and described by Carman-Kozeny type formula:

\[
k(\phi) = k_o \left( \frac{\phi}{\phi_o} \right)^{\mu} \left[ \frac{1-\phi_o}{1-\phi} \right]^2
\]

Here,
φ is the porosity at a given hydrate saturation.

φ₀ is the initial porosity.

Exponent (ε) is an empirical parameter varying between 1, 3, 5, and 10.

k(φ) is permeability dependent on hydrate saturation and is called effective permeability.

k₀ is the absolute or the initial permeability.

Figure (2.2) shows the change of relative permeability (ratio of effective to base permeability) with respect to hydrate saturation.

![Figure (2.2); Effective permeability as function of hydrate saturation](image)

Where, φ₀=0.35, and k₀=200m

**Solid Concentration of the Hydrate**

Solid concentration of the hydrate is defined in terms of g mole/pore-volume.

The solid concentration of the hydrate is calculated as given below:

Moles of hydrate = Sₜ * φ * Vₕ (m³) * ρₕ (kg/m³)/mol.wt of hydrate (kg/mole)…… eqn.1.

Therefore moles of hydrate density=moles of hydrate / pore volume (φ * Vₕ) ... eqn.2.
Substituting eqn.1. into eqn.2. gives;

Moles of hydrate = \( \frac{S_h \times \rho_h}{MW} \) ..............................................................2.9

Where;

\( S_h \) = Hydrate saturation \([V_H/V_p]\)

\( \phi \) = Porosity \([V_p/V_{rock ~ volume}]\)

\( V_{rock} \) = Rock volume \([m^3]\)

\( \rho_h \) = Hydrate density \([kg/m^3]\)

\( MW \) = Molecular weight \([kg/mol]\)

Note: 0.001 kg/mole = 1.0 g/mole

LIQUID AND GAS VISCOSITIES

Gas viscosity
This was calculated using correlation taken from CMG (STARS) manual.

\( \mu_g = AVG \cdot T^{BVG} \) ..............................................................2.10

Where,

\( \mu_g \); is the viscosity of the gas \((cp)\)

AVG; is the first coefficient in correlation to describe temperature dependence of viscosity of component in the gas phase.

BVG; is the second coefficient of correlation to describe temperature dependence of viscosity of component in the gas-phase.

The gas phase consists of methane only.

Liquid viscosity
This was calculated using correlation from CMG (STARS) manual.

\( \mu_l = A \cdot \exp (B/T) \) .........................................................2.11

The liquid phase consists of water only.
Equations for hydrate dissociation

The basic hydrate dissociation equation is given by

\[
CH_4 \cdot N_h H_2O_{(solid)} \leftrightarrow CH_4_{(gas)} + N_h H_2O_{(liquid)}
\]  \hspace{1cm} \text{2.12}

\( N_h \) is the hydration number

The properties of methane hydrate are summarized in Table 3\(^1\).

<table>
<thead>
<tr>
<th>Hydrate properties</th>
<th>Value</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hydration value</td>
<td>6 (6.75)</td>
<td></td>
</tr>
<tr>
<td>Mole fraction</td>
<td>1</td>
<td></td>
</tr>
<tr>
<td>Specific heat capacity</td>
<td>1600</td>
<td>J/ m(^3) K</td>
</tr>
<tr>
<td>Thermal conductivity</td>
<td>33950</td>
<td>J/m-day-K</td>
</tr>
<tr>
<td>Density (( \rho ))</td>
<td>919.7</td>
<td>Kg/ m(^3)</td>
</tr>
</tbody>
</table>

In CMG STARS, the equations below where used to calculate the formation and decomposition of hydrate.

**Hydrate formation**

\[
\frac{dc_h}{dt_{Form}} = A \exp \left( \frac{-E}{RT} \right) \left( \phi S_w \rho_w \right) \left( \phi S_h \rho_h y_i p_i \right) \left( 1 - \frac{1}{K(P,T)} \right) \] \hspace{1cm} \text{2.13}

**Hydrate decomposition**

\[
\frac{dc_h}{dt_{Decay}} = B(1 + \phi S_h) \exp \left( \frac{-\Delta E}{RT} \right) \left( \phi S_w \rho_w \right) \left( \frac{1}{K(P,T)} - 1 \right) \] \hspace{1cm} \text{2.14}

**Equilibrium State of Gas-Hydrate**

The phase equilibrium is described using \( K \)-value, describing the partition coefficient as function of pressure and temperature. In this simulation, a three-parameter \( K \) value correlation was used:
\[ K = \left( \frac{k_1}{P} \right) \exp \left( \frac{k_2}{T - k_3} \right) \]

Where, \( k_1, k_2, \) and \( k_3 \) are the fitting parameters.

The fitting parameters\(^6\), where given as;

\[ k_1 = 1.617408 \times 10^9 \]
\[ k_2 = -1414.909123 \]
\[ k_3 = -105.25 \]

**Fluid Enthalpies:**

Gas and liquid heat capacities are functions of temperature and are calculated by the correlation stated below.

In this simulation, the four-parameter gas and liquid heat capacity correlation along with vaporization enthalpy is used. The gas phase heat capacity \( C_{PG} (T) \), liquid phase heat capacity \( C_{PL} (T) \) and vaporization enthalpy \( H_{VAP} (T) \) for the condensable components were defined in CMG (STARS) manual as,

\[ C_{PG} (T) = C_{PG1} + C_{PG2} \times T + C_{PG3} \times T^2 + C_{PG4} \times T^3 \]
\[ C_{PL} (T) = C_{PL1} + C_{PL2} \times T + C_{PL3} \times T^2 + C_{PL4} \times T^3 \]

\( C_{PG1}, C_{PG2}, C_{PG3}, C_{PG4} \) are the gas heat capacity coefficients.
\( C_{PL1}, C_{PL2}, C_{PL3}, C_{PL4} \) are the liquid heat capacity coefficients.

The equations for the heat capacity and the enthalpy coefficients were obtained from the CMG (STARS) manual.

Simulations run for different reservoir model will be discussed in chapter three.
Chapter Three
Simulations

3.0 Reservoir model
The reservoir model used in this work consists of $31 \times 21 \times 20$ grid blocks. Each grid block measures $20\text{m} \times 40\text{m} \times 5\text{m}$, resulting in a rectangular reservoir $620\text{ m}$ long, $840\text{ m}$ wide and $100\text{ m}$ deep. The reservoir model consists of a total of 13020 grid blocks, with 20-layers in the k-direction, and 31 grid blocks in the i-direction, 21grid blocks in the j-direction as stated above. The typical model geometry used in present study is shown in Figure 3.1

![Model geometry](image)

Figure 3.1 Model geometry

3.0.1 Initial Conditions
The initial phase conditions consists of two phases namely, water and hydrates. The top of the reservoir consists of an overlying low permeable layer which prevents gas from escaping. The bottom of the accumulation is defined by the pressure and temperature gradient throughout the reservoir and lies $100\text{ m}$ below the top. The gas composition is $100\%$ methane, but the initial free gas saturation is assumed to be zero. Pressure gradient from sea level to the bottom of the reservoir is hydrostatic with an average sea water
density of 1025 kg/m³. The pressure-depth function from the top of the reservoir to the bottom of the reservoir is written mathematically as

\[ P \text{ (Pa)} = 9.635 \times 10^6 + 10250Z \text{ (m)} \] ..........................(3.0)

The temperature gradient describes changes in temperature around a particular location. The temperature gradient from sea level to the bottom of the deposit consists of two lines:

1. A gradual temperature decrease towards the sea floor where \( T \) is equal to 7.5°C
2. Below the sea floor the temperature increases gradually with depth with a value of 3.5°C/100m.

The temperature-depth function from the top of the reservoir to down is written as (assuming a temperature of 7.5 deg C at the sea level).

\[ T \text{ (°C)} = 7.5 + 0.035Z \text{ (m)} \] ..........................(3.1)

The initial water saturation and hydrate saturation were both assumed to be equal to 0.5, while the gas saturation was assumed to be zero.

**3.0.2 Boundary conditions**

As boundary conditions, it is given that there is no heat exchange within the beds confining the reservoir. This means that, there is no heat loss from the reservoir to the over-burden or under-burden.

The minimum bottom-hole pressure (MBHP) used in the simulation varies from 2500 KPa to 6000 KPa. This helps to choose a favorable bottom-hole pressure to avoid ice-formation.

**3.1 Assumptions and Input parameters**

**Assumptions base-case**

- As mentioned earlier, class-3-hydrate (single hydrate bearing layer with no underlying fluids) reservoir was considered.
- Homogeneous hydrate bearing layer.
- No aquifer present.
- Hydrate dissociation is described by equilibrium model.
- Constant bottom-hole pressure.
- Production method is depressurization.
- Production time: 11 years
Input parameters

The parameters used in this case are listed in Table 4 below.

**Table 4** Input parameters

<table>
<thead>
<tr>
<th>Parameters</th>
<th>Values</th>
</tr>
</thead>
<tbody>
<tr>
<td>Size of Reservoir (m)</td>
<td>620 x 840 x 100</td>
</tr>
<tr>
<td>Number of grid-blocks</td>
<td>31 x 21 x 20</td>
</tr>
<tr>
<td>Absolute Permeability (mD)</td>
<td>200</td>
</tr>
<tr>
<td>Hydration Number (N_h)</td>
<td>6 (6.75)</td>
</tr>
<tr>
<td>Porosity (%)</td>
<td>35</td>
</tr>
<tr>
<td>Water density (Kg/m³)</td>
<td>999.9</td>
</tr>
<tr>
<td>Sw</td>
<td>0.5</td>
</tr>
<tr>
<td>Sh</td>
<td>0.5</td>
</tr>
<tr>
<td>Sg</td>
<td>0</td>
</tr>
<tr>
<td>A</td>
<td>0.000424</td>
</tr>
<tr>
<td>B</td>
<td>2277.989</td>
</tr>
<tr>
<td>AVG</td>
<td>0.00019</td>
</tr>
<tr>
<td>BVG</td>
<td>0.761</td>
</tr>
</tbody>
</table>

Two different geological reservoir models namely, homogeneous and heterogeneous were created based on permeability variations within the layers.

The heterogeneous reservoir model consists of three different cases based on permeability variations.

- Case 1: Directional permeability
- Case 2: Stochastic (Random) permeability.
- Case 3: Layered permeability.

The representation of each reservoir is detailed in the next subsection.
3.1.1 Homogeneous model Base case

Figure 3.1.1 represents a homogeneous reservoir with a vertical production well placed at the corner of the reservoir. The absolute permeability in each layer is 200 mD in both vertical and horizontal direction. The top and bottom layers of the reservoir were set to have a zero permeability, which implies that they are impermeable layers. The porosity was taken to be 35 %. Figure 3.1.1 (a), and (b) shows constant permeability in I, K direction respectively, and permeability in J- direction is considered same as that of K-direction.

![Figure 3.1.1a](image1)  ![Figure 3.1.1b](image2)

**Figure 3.1.1a** Permeability in I-direction (b) Permeability in K-direction

3.1.2 Heterogeneous model

3.1.2.1 Directional Permeability

In this simulation, permeability was assumed to vary in different direction. Horizontal permeability ($k_h$) in i-direction was assumed to be 200mD, 100mD in j-direction, and
20mD in the vertical direction. This gives a heterogeneous reservoir model as shown in Figure 3.1.2.1, having different permeability in different directions as stated earlier.

![Permeability in I-direction](image1)

![Permeability in K-direction](image2)

![Permeability in J-direction](image3)

Fig.3.1.2.1. (a) Permeability in I-direction (b) Permeability in K-direction (c) Permeability in J-direction.

**3.1.2.2 Stochastic (Random) Permeability**

In order to simulate a real reservoir, stochastic permeability is modeled. The distribution was realized by assuming that permeability is randomly distributed within the range of 2-200 mD. This gives a heterogeneous reservoir as shown in Figure 3.1.2.2. The random
distribution was generated using Sequential Gaussian Simulation (SGSIM) Program\textsuperscript{17}. The random permeability was generated with this program, and imported to STARS data file. To have a good comparison with the heterogeneous case, average random permeability distribution was chosen 200 mD.

\begin{figure}[h]
\centering
\includegraphics[width=\textwidth]{randomly_distributed_perm_field}
\caption{Randomly distributed permeability field}
\end{figure}

3.1.2.3 Layered Permeability

In order to determine the effect of layering in the vertical direction, another heterogeneous case was modeled, having different permeability in each parallel layer. As shown in Figure 3.1.2.3, the upper layer has a permeability of 100 mD, the second has a value of 50 mD, third has 10 mD and the last is 200 mD.
3.2 Simulation strategy

Types of well considered are listed below

- **Vertical well**
  A production from vertical well placed at the corner and center of the reservoir to view its impact in decomposition of methane hydrate as discussed in homogeneous model base case above.

- **Horizontal well**
  The impact of horizontal well on optimizing production was considered.
  Two cases (A&B) of horizontal well were considered to see the effect of well-placement on optimizing production.

**Case A**
In the first case (A), a horizontal well was drilled from the centre of the reservoir. At a depth of 957.5m, from the surface, at a horizontal distance of 320m from the x-direction, as shown in the figure 3.2.0 below. The analysis of the production profile is shown in chapter four. The choice of the well position was made to increase the contact area between the well and the reservoir, in order to increase the cumulative production of gas and water.
In the second case, a horizontal well was drilled further away from the center; this is to increase the contact area between the well and the reservoir. The well was drilled at a depth of 957.5m, from the surface, and a horizontal distance of 620m from the x-direction, shown in the figure 3.2.1 below.
## Multiple wells

In configuring multiple wells in each case listed below, well spacing was calculated in order to see its impact in dissociation of gas-hydrate, and also the effect of interference due to communication that might result between the wells during production. The spacing between wells were calculated for different multiple well cases as shown below.

(a) 2-vertical wells:
Figure 3.2.2 2-Spot production well

According to Pythagoras theorem

\[ X^2 = y^2 + z^2 \]

\[ \text{...............(3.3)} \]

where, \( y = 240 \text{ m} \) and \( z = 320 \text{ m} \)

Substituting \( y \) and \( z \) in equation (3.3), gives \( x = 400 \text{ m} \)

The choice of \( y \) and \( z \) were based on trial and error method. The same equation and method ( trial and error method ) was applied for 3 and 5-vertical wells
(b) 3-vertical wells

Figure 3.2.3  3-vertical production wells

Apply equation (3.3) to calculate for \( x_m \), where \( y = 220 \text{ m} \) and \( z = 200 \text{ m} \). Therefore, \( x_m = 297.32 \text{ m} \).

(c) 5-vertical wells

Figure 3.2.4  5-Spot production wells

Here, \( z = 160 \text{ m} \), \( y = 280 \text{ m} \). and \( x \) was calculated to be 322.49 m.

The results of the simulation will be discussed in chapter four.
CHAPTER FOUR
RESULTS AND DISCUSSIONS

The results from the base case simulations and other cases are presented, described and discussed in this chapter. Thereby, changes in reservoir pressure, reservoir temperature, water saturation, gas saturation, and hydrate saturation in combination with the cumulative production of water and gas are discussed. The production strategies are compared. The total production time was 11 years or 25 years.

4.1 Reference case (Homogeneous reservoir)

The base case simulations describe the simulations from a three dimensional reservoir as shown in Figure 3.1. The depth of the hydrate bearing layer is 100m. One vertical well is drilled at the corner of the reservoir as indicated in Figure 3.1. To establish gas production from the gas hydrate bearing layers, the bottom-hole pressure is set to 3700 KPa and kept constant.

In the following the changes of various parameters such as reservoir pressure, temperature, and solid hydrate concentration are shown and discussed during a production time of eleven years.

4.1.1 Pressure

In Figures 4.1.1. a, b and c the pressure profiles at simulation times of 1, 5 and 11 years are shown. Over the time a pressure decline in the whole reservoir can be observed starting from the well. It is striking though that the lowest pressure is observed in the lowest part of the well. Nevertheless, the pressure declines away from the well as expected, and from the top to the lower layers.

4.1.2 Temperature

In Figure 4.1.2. a, b and c the temperature profiles of the same simulation are shown after 1, 5 and 11 years. Initially the temperature increases with increasing depth due to the thermal gradient. After a simulation time of one year, it can be seen that the temperature in the lowest part of the well is the lowest. The temperature increases from the lowest
part of the well further into the reservoir up to its initial temperature. It can be seen that gradually the temperature is decreasing with increasing simulation time. The decrease starts from the well and spreads into the reservoir.

Figure 4.1.1. Pressure distribution (f) at 11th year (a) at 1st year (b) at 5th year and (c) at 10th year

Figure 4.1.2. Temperature distribution (a) at 1st year, (b) at 5th year, and (c) 10th year
4.1.3 Hydrate Saturation

In Figure 4.1.3 a to d the change of the solid phase concentration of the methane hydrates after 1, 5 and 11 years of production is shown. The hydrate dissociation is a result of changes in reservoir pressure and temperature. Due to the pressure drop, hydrate starts to decompose. It can be seen that dissociation first occurs in the lowest layer close to the well. A decrease of gas hydrate concentration is seen in vertical direction and in a smaller degree in horizontal direction. First, the gas hydrates in the lower layers of the reservoir are dissociated.

Figure 4.1.3 Methane-hydrate decomposition (a) at 1st year (b) at 5th year (c) at 8th year and (d) at 10th-year
4.1.4 Water and Gas saturations

In this simulation methane hydrate dissociation is induced by lowering the pressure in the well. The gas hydrate dissociates into methane and water. At the given conditions, water is liquid and methane is gas. As the saturation of the gas hydrates in the reservoir decreases, the saturation of gas (methane) and (liquid) water increases. In Figure 4.1.4. a to f, the gas and water saturation profiles throughout the reservoir at simulation times of 1, 5 and 11 years are depicted. Note thereby, that initially it is assumed that there is no free gas in the reservoir and that the presence of hydrates is not reflected in the saturation values but solely in the solid phase concentration. Consequently, the initial water saturation throughout the whole reservoir is equal to one and of the gas equal to zero.

The water and gas saturations are changing very slowly. After a simulation time of one year, the changes are so slight that they are not visible in the profiles shown in Figure 4.1.4.a to f. With further increasing simulation time it can be seen that the gas saturation increases close to the well, increasing further in vertical direction. Consequently, the water saturation decreases accordingly. After 11 years the gas saturation has increased throughout the whole reservoir. However, only in the top layers and close to the well the changes are evident enough to show in the profiles. During the liberation of gas and water, the gas moves upward while the water moves down due to gravity effects.

It should be noted that the plots depicting the gas and water saturation in the whole reservoir do not really help in understanding how the production of gas from gas hydrate bearing layers occurs due to the fact that gas hydrates are assumed to form part of matrix rather than to be considered as a solid phase filling the pore space. Consequently, these plots will only be used in the subsequent text and discussions if they really support the understanding of the results.
Figure 4.1.4 (a-c) Water saturation distribution (a) at 1st year (b) at 5th year and (c) 11th year

Figure 4.1.4(d-f) Gas saturation distribution (d) at 1st year (e) at 5th year and (f) 11th year
4.1.5. Cumulative gas and water production.

With the description of the simulations using the plots displaying the temperature, pressure, and gas hydrate solid concentration the graphs displaying the cumulative gas and water production can be analyzed.

Initially, the pressure gradually drops isothermally before reaching the gas hydrate equilibrium line. Consequently, the gas hydrates dissociate so that gas and water are liberated. Due to the endothermic nature of hydrate dissociation and the Joule-Thomson effect, the temperature drops. If the pressure decline is not sufficient to stay at conditions below the equilibrium line, hydrates will be formed again heating up the surroundings slightly. Hydrate dissociation is observed first in the lower layers because there the temperature is high enough and the pressure low enough for the hydrates to dissociate (see Figure 1.4, see Figure 4.1.1, 4.1.2 and 4.1.3). At the top of the reservoir, initially, the pressure decline at the given temperatures is not enough to dissociate the gas hydrates. Because the gas and the water are immediately produced from the reservoir, as also the dissociation starts at the well, there is hardly a change in water and gas saturation in the reservoir observed. Only after longer simulation times, after also hydrates further in the reservoir have been dissociated, changes in the gas and water saturation can be observed.

In Figure 4.1.5.a the cumulative gas and water production over the complete simulation time of 11 years are shown. The cumulative production of water and gas increases steadily. Thereby, more gas was produced than water (in volume). This explains also why the gas saturation values in the reservoir hardly change. While after 11 years of production the water production seems to become constant, the gas production keeps on increasing. This continuously increasing cumulative gas production can be explained by the fact that more gas hydrates further in the reservoir have dissociated so that the gas can be transported easily through the reservoir as the permeability increases with decreasing gas hydrate concentration (See also Figure 4.1.5.b). Additionally, water and gas separate due to gravity segregation so that gas is produced from the top layers.
Figure 4.1.5.a Cumulative gas and water production with pressure and temperature

Figure 4.1.5.b Permeability distribution (a) at 1st year and (b) 10th-year
4.2 Heterogeneous Reservoir

4.2.1 Directional permeability

In the following the results of the simulation are shown for which it was assumed that in absence of hydrates the vertical permeability is a tenth and fifth of the horizontal (i and j) permeability (see Figure 3.1.2.1.a to c). With this simulation the sensitivity of the results on the permeability can be identified. In Figure 4.2.1 the resulting cumulative water and gas productions are shown. Comparing the cumulative production results with the base case, it can be seen that after a production time of 11 years less gas is produced if a lower vertical permeability is assumed – around 1.6e7 m3 instead of 5e7 m3 for the base case. The water production has also decreased, even though only slightly. The lower production can be explained by the fact that due to the reduced vertical permeability gas and water segregate less due to gravity. Additionally, the pressure and temperature decrease spreads less fast through the reservoir. After 11 years of production the lowest pressure in the reservoir is found at the lowest point of the well and is equal to 4.2 MPa. This is higher than for the base case for which the lowest pressure encountered was 3.9 MPa also at the lowest point of the well (see Figure 4.2.1.a-b in Appendix B). The lowest temperature is also found at the lowest point of the well and is 6.3°C. For the base case the lowest temperature was encountered at the same spot but was 5°C (see Figure 4.2.1.c-d in Appendix B). These points are both on the equilibrium line describing the transition between the region in which hydrates are stable and the liquid-vapor region (see Figure 1.4). It can be seen that the gas hydrate dissociation starts at the lowest point close to the well and spreads then first almost spherical before it spreads more into horizontal direction. This is also reflected in the porosity profile (see Figure 4.2.1.g-h in Appendix B). The transport of the water and the gas through the reservoir is hindered by the lower permeability in vertical direction so that a clear change of the gas and the water saturation in the reservoir can be seen (see Figure 4.2.1.k-n in Appendix B). The profile showing the gas and water saturations together with the gas hydrate solid concentration profile indeed proof why the gas production decreased compared to the base case.
Figure 4.2.1. Cumulative gas and water production with pressure and temperature
4.2.2 Random permeability
It was seen that reducing the vertical permeability has clear effect on the results of the simulation. In the following it was assumed that the permeability changed randomly as it was explained in Chapter Three (see Figure 3.1.2.2). In Figure 4.2.2., the cumulative production of gas and water as function of time is shown. After 10 years of production the cumulative production is lower than for the base case and even lower than for the case in which it was assumed that the vertical permeability is 10% and 5% of the horizontal (i and j) permeability. The distribution of the temperature and the pressure in the reservoir (see Figure 4.2.2.a-d in Appendix B) occurs similar to the pressure and temperature distribution in the simulation for which a homogenous permeability field was assumed. Interestingly, the pressure and the temperature dropped faster in the case of the random permeability field than in case of homogenous permeability. As a consequence, even though the pressure has lowered faster, there is less gas hydrate dissociation because the temperature has dropped too much to reach the equilibrium line (see Figure 4.2.2 e-f in Appendix B and also Figure 1.4).

Figure 4.2.2. Cumulative gas and water production with pressure and temperature
4.2.3 Layered permeability

In this simulation the reservoir was divided into four equally thick horizontal layers to which different permeability values were assigned. The permeability values of the different layers (from top to bottom) are 100, 50, 10 and 200 mD, respectively. The cumulative gas and water production after 11 years is less than for the base case, but higher than random and directional permeability reservoir. Studying the pressure, temperature, saturation and solid concentration profiles of the simulation with a layered permeability field it becomes obvious that the increase in gas production is due to the more pronounced gas hydrate dissociation in the high permeability regions. (see Figure 4.2.3.e-h in appendix B)

Table 5 summarizes the results of the various simulations for which the permeability field was varied while keeping all other parameters constant. A single vertical production well was situated at the corner of the reservoir. The results are expressed in terms of the cumulative gas and water production. As already mentioned in the discussion above, the highest cumulative gas production combined with the lowest water production, after
11 years of production, was found for the layered permeability field case. The lowest cumulative gas production was found for the directional permeability field.

From this study it becomes obvious how important a good characterization of the reservoir is. Unfortunately, there are no field data to validate the results. Nevertheless, it can be concluded that a homogenous reservoir gives the best results, followed by layered permeability reservoir with respect to production of gas and water.

**Table 5 Production profile of Heterogeneous reservoir with bottom-hole pressure of 3700KPa.**

<table>
<thead>
<tr>
<th>Homogeneous reservoir</th>
<th>Cumulative gas Sc produced [m³] after 11 yrs</th>
<th>Cumulative water Sc produced [m³] after 11 yrs</th>
<th>Pressure after [KPa] 11 yrs</th>
<th>Temperature [°C] after 11 yrs</th>
<th>G_p/G_t (Vol. %)</th>
<th>W_p/W_t (Vol. %)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Single Vertical well</td>
<td>5.1e+007</td>
<td>1.6e+005</td>
<td>3721.53</td>
<td>7.3</td>
<td>3.4</td>
<td>0.99</td>
</tr>
<tr>
<td>Heterogeneous reservoir</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Directional field</td>
<td>1.6e+007</td>
<td>1.5e+005</td>
<td>4037.69</td>
<td>8.8</td>
<td>1.1</td>
<td>0.89</td>
</tr>
<tr>
<td>Random field</td>
<td>1.8e+007</td>
<td>1.3e+005</td>
<td>3868.97</td>
<td>8.6</td>
<td>1.2</td>
<td>0.78</td>
</tr>
<tr>
<td>Layered field (layer 1-100, Layer 2 – 50, Layer 3 – 10, Layer 4 – 200) mD.</td>
<td>2.3e+007</td>
<td>1.1e+005</td>
<td>3714.19</td>
<td>8.5</td>
<td>1.6</td>
<td>0.66</td>
</tr>
</tbody>
</table>
4.3 Horizontal Well Production Scenario

In the following the influence of the location of a single horizontal well on the production of gas and water from the same hydrate bearing layer as stated above is studied. Case A describes the simulation for which the well was drilled from the center and at a depth of 957.5 m (See Figure 3.2.0). In case B, the well was drilled from the corner of the reservoir at same depth of 957.5 m (see Figure 3.2.1) but at different horizontal distance. All the other parameters have been kept the same as for the base case scenario.

4.3.1 Case A

In Figure 4.3.1, the cumulative gas and water production of the simulation with a single horizontal well drilled from the center of the reservoir is depicted. After 11 years of production, the cumulative produced volume of gas and water is clearly higher than it was found for the simulations of the base case. This can be explained by the easier transport of water and gas to the long horizontal production well. Differently than for the results of the vertical well scenario’s a flattening of the gas production can be seen after a production time of around 8 years which is caused by gravity segregation between the gas and the water phase (See also Figure 4.3.1. i-l in Appendix C). Consequently, less gas flows into the production well. As can be seen in (Figure 4.3.1.c-d in Appendix C) the temperature in some parts of the reservoir dropped so far, that at the given pressure, hydrate formation occurs.
**4.3.2 Case B**

In Figure 4.3.2.a the cumulative water and gas production of the simulations with a horizontal well drilled from one corner of the reservoir (See Figure 3.2.1.) are given. The cumulative water production is higher than for the horizontal well drilled from the center. The gas production is about the same as for the simulations with a horizontal well drilled from the center. These two differences can be explained by the fact that the contact area between the horizontal well of the case B and the reservoir is actually longer. Consequently, more water can flow into the well. The gas production does not increase because, due to gravity segregation only the gas originating from the dissociated gas hydrates which lay below the well are produced just as it was already observed for the horizontal well drilled from the center.

---

Figure 4.3.1.a Cumulative gas and water production of a horizontal well in case A
Figure 4.3.2.a Cumulative gas and water production of a horizontal well in case B.

In Figure 4.3.2.b the resulting cumulative water and gas production of a simulation with a single well drilled from the corner but with a bottom-hole pressure of 2500 KPa instead of 3700 KPa are shown. As a result of this the initial cumulative gas production has increased compared to the simulation with the higher bottom-hole pressure but same conditions. Further, the final cumulative gas production increased from around 1e8 m3 to 2.2e8 m3. This can be explained by the fact that the bigger pressure drop towards the well induces the gas also to be carried along with the water even though it results from layers clearly above the horizontal well. This explanation is also supported by the higher cumulative water production. (see also Figure 4.3.2.b).
4.4 Multiple Well Scenarios

In the following, the impact of multiple wells on the production from a gas hydrate bearing layer was considered. For this purpose simulations for 11 years have been run with two, three and five vertical production wells. Just as in the cases discussed before, depressurization was used as production method. Thus the bottom-hole pressure was kept constant during simulations but varied to optimize the production. Results from the simulation with a single horizontal well show that the cumulative gas production is influenced by the pressure draw-down, thus the bottom-hole pressure chosen for the study.

4.4.1. 2-vertical production wells using bottom-hole pressure of 2500KPa.

In Figure 4.4.1.A the simulation results with two vertical wells are shown. The bottom-hole pressure is set to 2500 KPa. The distance between the two wells is 400m (see Figure 3.2.2). From the pressure and temperature profiles it can be seen that the pressure increases from the well towards the reservoir. As expected the pressure declines faster than for a single vertical well. Also the temperature decrease is faster and develops from
the wells into the reservoir. After 11 years of production the complete reservoir has reached a pressure of 2524 KPa, the temperature in the upper layers has dropped to 1° C and only in the lowest layer it is still around 3° C. This is a result of the interference of the two wells. At 1° C the equilibrium pressure at which the methane hydrates just dissociate is 2500 KPa (See Figure 1.4). Due to the low bottom hole pressure and the production from two vertical wells, in the upper layers of the reservoir the gas hydrate have (almost) completely been produced (see Figure 4.4.1.i in Appendix D). Also during this simulation gravity segregation occurs which only supports the depleting of the gas hydrate bearing layer. The lower temperature reached after 11 years of production is due to the endothermic nature of gas hydrate as discussed in the single vertical well production (base case) but also due to Joule-Thomson effect close to the production wells.

The cumulative gas and water production is displayed in Figure 4.4.1. The cumulative gas and water production is clearly higher than for the base case scenario. This is partly also due to the fact that the bottom hole pressure was chosen to be 2500 KPa for the 2-vertical production wells while it was 3700 KPa for the single vertical well of the base case. Nevertheless, the increase in production cannot solely be described by this. The cumulative gas production for the scenario with two vertical wells is as high as for a single horizontal well drilled from the corner of the reservoir. However, the cumulative water production is lower than for the horizontal well which is of advantage (see also Figure 4.1.5.a in Appendix A). However, differently than in the case with a horizontal well and a bottom-hole pressure of 2500 KPa the cumulative gas production curve does not flatten out. This is due to the fact that eventually all gas hydrates may be produced because the gas can always reach the production well.
4.4.2. 3-vertical production wells with a bottom-hole pressure of 2500KPa

In Figure 4.4.2.a the cumulative gas and water production for the scenario with three vertical production wells are shown. The cumulative water production is higher than the 2-vertical production wells. The cumulative gas production after 11 years is about the same. Interestingly, the cumulative gas production curve flattens after around 7 years to a constant value of around 2.2e8m3. From the temperature and pressure profiles it cannot be concluded why this flattening of the cumulative gas production curve occurs. The temperatures and pressure stay just below the equilibrium curve (which describes the re-appearance of hydrates). Also the solid hydrate concentration does not help to find the reason for this. But just as for the 2-vertical production wells the temperature and pressure profiles clearly show the interference of the wells.
In Figure 4.4.2b the results of the simulation with three production wells for a simulation time of 25 years is shown. The reservoir pressure dropped to 2509 KPa, which is close to the bottom-hole pressure (2500 KPa) giving rise to more hydrate dissociation due to increase in pressure drop. It is interesting to see that the temperature does not further drop, e.g., below zero degrees where ice formation would hinder gas production. While the cumulative gas production stays almost constant at around 2.2e8 m³, the water production continuously increases. This can also be seen in Figure 4.4.2.c in which the
average gas and water saturation as function of time is plotted. With increasing time the gas saturation continuously increases while the water saturation decreases.

Figure 4.4.2b. Cumulative water and gas production with pressure and temperature
4.4.3A 5-vertical production wells with uniform permeability (11 years)

It was seen that the cumulative gas production could be enhanced when two vertical wells are used instead of a single vertical well. More of the gas hydrates could be dissociated in the reservoir if even more wells were used, e.g., three vertical wells. However, the cumulative gas production when applying a 3-vertical well scenario was not increased sufficiently to make the investment viable. In the following simulation the cumulative gas and water production is studied for 5-vertical production wells are placed. In Figure 4.4.3.A.a the cumulative gas and water production as function of time is shown. The simulation was done for 11 years of production. From Figure 4.4.3.A.a it can be seen that the cumulative gas production could not be increased compared to the two or three-vertical well scenario. Only the time before the stable value of around 2.2e8 m³ of cumulative gas production is clearly shorter for the 5-vertical well scenario (4 years) compared to the other simulations involving vertical wells. This is due to the fact that 5-vertical production wells, kept at a constant bottom hole pressure of 2500 KPa, have a higher production rate (as also can be seen in Figure 4.4.3.A.a ). However, the cumulative
water production increased. After ten years of production the cumulative water production curve keeps increasing indicating that water production also continues for longer simulation times. The low spacing between the wells smoothens the temperature, pressure decline and also how the gas hydrates dissociate. Consequently, the pressures and temperatures reached after 11 years are lower than for the single vertical well scenario and also slightly lower than for the 3-spot scenario. However, the temperature never drops below zero degrees so that no problems due to ice formation need to be accounted for. Another point worth mentioning is that the reservoir depletes of gas hydrates moving from the top to the bottom layer.

Figure 4.4.3A.a  Cumulative water and gas production with pressure and temperature
Figure 4.4.3.A.b. Cumulative water and gas production with pressure and temperature

In Figure 4.4.3.A.b. the cumulative gas and water production of a time span of 25 years is shown. It can be seen that just as for the 3-vertical well scenario, the cumulative gas production could not be increased by extending the production time. The cumulative water production kept on increasing just as it was expected. Figure 4.4.3.A.c indicates that even though more gas hydrates clearly have been dissociated, the gas cannot be produced. Instead, the gas saturation kept increasing in the reservoir due to gravity segregation.

Figure 4.4.3A.c. Average water and gas saturation
**4.4.3B  5-vertical production well \( k_v=0.1k_h \) for 25 yrs.**

From the results of the single vertical well scenario it was concluded that the permeability field strongly influences the results. Therefore, it was assumed that the permeability in vertical direction is 10% of the permeability in the horizontal direction. Further, for the production the five spot scenarios were used with a constant bottom-hole pressure of 2500kPa. In figure 4.4.3.B.a the cumulative water and gas production are displayed as function of time. The cumulative gas production after 25 years of production is lower than for the homogenous permeability field in the five-spot scenario. Additionally, the cumulative gas production still increases after 25 years. It is striking to notice that the cumulative gas production first increases strongly then levels almost out to a constant value after around 2 years before it starts to incline again after 20 years. The cumulative water production shows a similar shape as before but is also lower than for the homogenous permeability field. Figure 4.4.3.B.b also shows that the average water saturation decreases more slowly than in the case of the homogenous field.

![Graph](image_url)

Figure 4.4.3.B.a Cumulative water and gas production with pressure and temperature

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Figure 4.4.3.B.b Average water and gas saturation
The production plots are shown in Appendix B.

**Figure 4.4.3.C BHP (above 2500 KPa)**

It was seen that the bottom-hole pressure has also a strong influence on the success of the gas production from gas hydrate bearing layers by depressurization. To get a better feeling what the effect of the bottom-hole pressure is, the bottom hole pressure was increased to 6000KPa in the 5-vertical production well scenario.(see figure 4.4.3.C.a). It was observed that an increased bottom-hole pressure caused a lower cumulative gas and water production after 10 years. This is caused by the fact that a higher bottom-hole pressure induces less pressure reduction in the reservoir and therefore also less gas hydrates dissociation. The flow of gas and water towards the production wells is less due to this lower pressure draw down. This becomes also visible from Figure 4.4.3.C.b in which the average water and gas saturation is displayed as function of time. Now the water saturation only decreases to 0.8 from its initial 1.0. For a bottom-hole pressure of 2500 KPa the water saturation has decreased as far as 0.5.
Figure 4.4.3.C.a  Cumulative water and gas production with pressure and temperature

![Graph showing cumulative gas and water production with pressure and temperature.]

Figure 4.4.3.C.b  Average water and gas saturation

![Graph showing average water and gas saturation over time.]

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Table 6 shows a summary of the cumulative production of water and gas and the average pressure and temperature in the reservoir after 11 years of production. For all these scenarios the bottom-hole pressure was 3700 KPa.

<table>
<thead>
<tr>
<th>Homogeneous reservoir</th>
<th>Cumulative gas Sc produced [m³] 11yrs</th>
<th>Cumulative water Sc produced [m³] 11yrs</th>
<th>Pressure after 11yrs [KPa]</th>
<th>Temperature after 11yrs [°C]</th>
<th>Gp/Gt (Vol. %)</th>
<th>Wp/Wt (Vol. %)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Single-Vertical well</td>
<td>5.1e+007</td>
<td>1.6e+005</td>
<td>3721.53</td>
<td>7.3</td>
<td>3.39</td>
<td>0.99</td>
</tr>
<tr>
<td>Two-Vertical wells</td>
<td>1.016e+008</td>
<td>6.0e+005</td>
<td>3710.24</td>
<td>4.5</td>
<td>6.79</td>
<td>3.7</td>
</tr>
<tr>
<td>Five-Vertical wells</td>
<td>1.012e+008</td>
<td>8.1e+005</td>
<td>3707.22</td>
<td>3.8</td>
<td>6.77</td>
<td>4.9</td>
</tr>
<tr>
<td>Horizontal well drilled from the center.</td>
<td>1.013e+008</td>
<td>5.2e+005</td>
<td>3745.83</td>
<td>3.6</td>
<td>—</td>
<td>—</td>
</tr>
<tr>
<td>Horizontal well drilled from the corner (edge)</td>
<td>1.019e+008</td>
<td>6.6e+005</td>
<td>3709.42</td>
<td>3.5</td>
<td>6.8</td>
<td>4.1</td>
</tr>
</tbody>
</table>

Table 7 gives the cumulative gas and water production, the average temperature and pressure after 11 years of production for the simulations with a bottom-hole pressure of 2500 KPa.
Table 7 single and multiple wells with bottom-hole pressure of 2500 KPa.

<table>
<thead>
<tr>
<th>Homogeneous reservoir</th>
<th>Cumulative gas Sc produced [m³]</th>
<th>Cumulative water Sc [m³]</th>
<th>Pressure [KPa]</th>
<th>Temperature [°C]</th>
<th>Gₚ/Gₜ (Vol. %)</th>
<th>Wₚ/Wₜ (Vol. %)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Single vertical well for 11 yrs</td>
<td>1.80e+008</td>
<td>4.6e+005</td>
<td>2538.56</td>
<td>1.7</td>
<td>12.1</td>
<td>2.7</td>
</tr>
<tr>
<td>Single vertical well for 25 yrs</td>
<td>2.15e+008</td>
<td>7.2e+005</td>
<td>2520.79</td>
<td>1.3</td>
<td>14.4</td>
<td>4.4</td>
</tr>
<tr>
<td>Two Vertical wells for 11 yrs</td>
<td>2.14e+008</td>
<td>6.8e+005</td>
<td>2524.51</td>
<td>2.2</td>
<td>14.3</td>
<td>4.1</td>
</tr>
<tr>
<td>Two Vertical wells for 25 yrs</td>
<td>2.21e+008</td>
<td>1.0e+006</td>
<td>2513.18</td>
<td>1.4</td>
<td>14.8</td>
<td>6.5</td>
</tr>
<tr>
<td>Three Vertical wells for 11 yrs</td>
<td>2.20e+008</td>
<td>8.8e+005</td>
<td>2518.35</td>
<td>1.7</td>
<td>14.7</td>
<td>5.4</td>
</tr>
<tr>
<td>Three Vertical wells for 25 yrs</td>
<td>2.22e+008</td>
<td>1.3e+006</td>
<td>2508.99</td>
<td>1.0</td>
<td>14.9</td>
<td>8.3</td>
</tr>
<tr>
<td>Five Vertical wells for 11 yrs</td>
<td>2.23e+008</td>
<td>1.2e+006</td>
<td>2512.2</td>
<td>1.1</td>
<td>14.95</td>
<td>7.5</td>
</tr>
<tr>
<td>Five Vertical wells for 25 yrs</td>
<td>2.24e+008</td>
<td>1.7e+006</td>
<td>2504.87</td>
<td>1.0</td>
<td>14.96</td>
<td>10.7</td>
</tr>
<tr>
<td>Five Vertical for longer</td>
<td>1.93e+008</td>
<td>1.3e+006</td>
<td>2576.17</td>
<td>1.12</td>
<td>12.97</td>
<td>8.5</td>
</tr>
</tbody>
</table>
wells for 25yrs with Kv=0.1Kh.

<table>
<thead>
<tr>
<th></th>
<th>period</th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Horizontal well</td>
<td>2.23e+008</td>
<td>1.1e+006</td>
<td>2502</td>
<td>1.03</td>
</tr>
<tr>
<td>drilled from the</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>corner (edge) for</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>11 yrs</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Horizontal well</td>
<td>2.24e+008</td>
<td>1.5e+006</td>
<td>2501.5</td>
<td>1.00</td>
</tr>
<tr>
<td>drilled from the</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>corner (edge) for</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>25yrs</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Two limitations were observed from the horizontal well.

1) It was seen that only gas hydrates below or in the vicinity of the horizontal well were produced. The gas originating from layers clearly above the horizontal well cannot be transported by the horizontal well due to gravity segregation (tendency of immiscible liquids or multicomponent mixtures to separate into distinct layers in accordance with their respective densities), unlike vertical (2-vertical production well) wells were all the dissociated gas was produced.

2) Water production from the horizontal well scenario was high compared to the vertical well scenario; this creates extra costs, since the water needs to be treated before disposal.

For the choice of horizontal well scenario to be more attractive, two factors need to be considered.

1) The thickness of the reservoir: Thick reservoirs have higher productivity as a result of the volume of the reservoir. Reservoirs with large volume have more contact area between the well and reservoir and prevents bore-hole instability. In
a thin reservoir, the productivity is lower due to the low contact area between the well and the reservoir, furthermore it's prone to bore-hole instability.

2) Position of the horizontal well: drilling from the bottom of the reservoir was not favorable due to gravity segregation effect as observed in this work. Placing the horizontal well at the middle layer(s) of the reservoir would likely dissociate more gas-hydrate and avert the problem of gravity segregation.
CHAPTER FIVE
Conclusions and Recommendations

5.1 Conclusions

In this study gas production from a class-3 gas hydrate reservoir by depressurization was studied. Various scenarios have been simulated to get a better understanding of how different parameters, such as permeability, bottom hole pressure, well spacing, kinds of wells etc, influence the gas production. The production efficiency of a single vertical and a single horizontal well have been studied and also the best arrangement of multiple vertical wells.

The major conclusion that can be drawn from this study are given below

- For the simulations with a single horizontal well it was seen that only gas hydrates below or in the vicinity of the horizontal well were produced. The gas originating from layers clearly above the horizontal well was not transported to the horizontal well but moved upwards in the reservoir due to gravity segregation. This behavior was not observed for the scenarios with vertical wells.

- Water production from the horizontal well scenario was observed to be higher compared to the vertical well scenarios.

- It was found that bottom-hole pressure chosen for the producer has great impact on the efficiency of the production from a gas hydrate reservoir. The bottom hole pressure was varied and it was found that a bottom pressure of 2500 KPa results in a higher gas production without hindrance by ice formation.

- It was found that with a single vertical well a layered reservoir is swept more efficiently than a reservoir in which the permeability is randomly distributed or in which the vertical permeability is a tenth of the horizontal permeability. The
pressure distribution is more equally distributed in the layered reservoir than in other cases.

- The two vertical production wells scenario was observed to be more attractive due to its efficient production than other scenarios considered. This is because; there was little communication between the 2-vertical production wells due to the chosen spacing between the wells. That does not mean that other scenarios cannot be improved in order to increase its production.

### 5.2 Recommendations

Based on the simulations of the different scenarios and also the analysis of the data some recommendations can be given for future work:

- Consider a deviated well in a heterogeneous layered reservoir. In this way most areas of the reservoir will be reached and swept. Additionally, a higher pressure draw-down over a longer range of the reservoir can be established which increases production.

- The effect of ice-formation and secondary hydrate formation should be studied to see its impact on production efficiency.

- The effect of the reservoir thickness on the production by means of a horizontal well should be studied in order to know, if it is more efficient to produce with a horizontal well or multiple vertical wells.
References


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Appendix

Appendix A: Single well placed at the center

Figure 4.1.5.a Cumulative gas and water production with bottom-hole pressure of 3700 KPa (11yrs), while b shows production with bottom-hole pressure of 2500 KPa (25yrs), and c shows the permeability for the 11th year (2500KPa).
Appendix B

4.2.1 Directional permeability reservoir

Figure 4.2.1.a. 1\textsuperscript{st} year
Pressure distribution

Figure 4.2.1.b. 11\textsuperscript{th} year
Pressure distribution

Figure 4.2.1.c. 1\textsuperscript{st} year
temperature distribution

Figure 4.2.1.d. 11\textsuperscript{th} year
temperature distribution

Figure 4.2.1.e. 1\textsuperscript{st} year
hydrate saturation distribution

Figure 4.2.1.f. 11\textsuperscript{th} year
hydrate saturation distribution
Figure 4.2.1.g. 1st year
Permeability distribution

Figure 4.2.1.h. 11th year
Permeability distribution

Figure 4.2.1.i. 1st year
Water saturation distribution

Figure 4.2.1.j. 11th year
Water saturation distribution

Figure 4.2.1.k. 1st year
Gas saturation distribution

Figure 4.2.1.l. 11th year
Gas saturation distribution
4.2.2 Random permeability production

Figure 4.2.2.a. 1st year
Pressure distribution

Figure 4.2.2.b. 11th year
Pressure distribution

Figure 4.2.2.c. 1st year
Temperature distribution

Figure 4.2.2.d. 11th year
Temperature distribution

Figure 4.2.2.e. 1st year
Hydrate saturation distribution

Figure 4.2.2.f. 11th year
Hydrate saturation distribution
4.2.3 Layered permeability reservoir

Figure 4.2.3.a. 1\textsuperscript{st} year
Pressure distribution

Figure 4.2.3.b. 1\textsuperscript{11\textsuperscript{th}} year
Pressure distribution
Figure 4.2.3.c. 1st year
temperature distribution

Figure 4.2.3.d. 11th year
temperature distribution

Figure 4.2.3.e. 1st year
hydrate saturation distribution

Figure 4.2.3.f. 11th year
hydrate saturation distribution

Figure 4.2.3.g. 1st year
porosity distribution

Figure 4.2.3.h. 11th year
porosity distribution
Figure 4.2.3.i. 1st year permeability distribution
Figure 4.2.3. j. 11th year permeability distribution

Figure 4.2.3.k. 1st year water saturation distribution
Figure 4.2.3. l. 11th year water saturation distribution

Figure 4.2.3.m. 1st year gas saturation distribution
Figure 4.2.3. n. 11th year gas saturation distribution
Appendix C
4.3.1 Horizontal well drilled from the center with bottom-hole pressure 3700KPa

Figure 4.3.1.a. 1st year
Pressure distribution

Figure 4.3.1.b. 11th year
pressure distribution

Figure 4.3.1.c. 1st year
temperature distribution

Figure 4.3.1.d. 11th year
temperature distribution

Figure 4.3.1.e. 1st year
hydrate saturation distribution

Figure 4.3.1.f. 11th year
hydrate saturation distribution
Figure 4.3.1.g. 1st year porosity distribution

Figure 4.3.1.h. 11th year porosity distribution

Figure 4.3.1.i. 1st year Water saturation distribution

Figure 4.3.1.j. 11th year Water saturation distribution

Figure 4.3.1.k. 1st year gas saturation distribution

Figure 4.3.1.l. 11th year gas saturation distribution
4.3.2 Horizontal well drilled from the corner point with bottom-hole pressure 3700KPa

Pressure

Figure 4.3.2.a. 1st year pressure distribution

Temperature

Figure 4.3.2.c. 1st year temperature distribution

Figure 4.3.2.f. 11th year hydrate saturation distribution

Figure 4.3.2.b. 11th year pressure distribution

Figure 4.3.2.d. 11th year temperature distribution

Figure 4.3.2.e. 11th year hydrate saturation distribution
Figure 4.3.2.g. 1st year water saturation distribution

Figure 4.3.2.h. 11th year water saturation distribution

Figure 4.3.2.i. 1st year gas saturation distribution

Figure 4.3.2.j. 11th year gas saturation distribution

Figure 4.3.2.k. 1st year porosity distribution

Figure 4.3.2.l. 11th year porosity distribution
Appendix D

4.4.1 2 vertical production wells (2500KPa)

Figure 4.4.1.a. 1st year pressure distribution

Figure 4.4.1.b. 1st year temperature distribution

Figure 4.4.1.c. 11th year pressure distribution

Figure 4.4.1.d. 11th year temperature distribution

Figure 4.4.1.e. 1st year water saturation distribution

Figure 4.4.1.f. 1st year gas saturation distribution
Figure 4.4.1.g. 11\textsuperscript{th} year
water saturation distribution

Figure 4.4.1.h. 11\textsuperscript{th} year
gas saturation distribution

Figure 4.4.1.i. 11\textsuperscript{th} year
hydrate dissociation distribution

Figure 4.4.1.j. 11\textsuperscript{th} year
porosity distribution
4.4.2. A 3-vertical production wells with a bottom-hole pressure of 2500KPa

Figure 4.4.2A.a. 1st year pressure distribution
Figure 4.4.2A.b. 1st year temperature distribution
Figure 4.4.2A.c. 11th year pressure distribution
Figure 4.4.2A.d. 11th year temperature distribution
Figure 4.4.2A.e. 1st year hydrate dissociation distribution
Figure 4.4.2A.f. 1st year porosity distribution
Figure 4.4.2A.g. 11th year hydrate dissociation distribution

Figure 4.4.2A.h. 11th year porosity distribution

Figure 4.4.2A.i. 1st year water saturation distribution

Figure 4.4.2A.j. 1st year gas saturation distribution

Figure 4.4.2A.k. 11th year water saturation distribution

Figure 4.4.2A.l. 11th year gas saturation distribution
4.4.2B 3-vertical production wells with a bottom-hole pressure of 2500KPa

Figure 4.4.2B.a. 25th year pressure distribution

Figure 4.4.2B.b. 25th year temperature distribution

Figure 4.4.2B.c. 25th year hydrate dissociation distribution

Figure 4.4.2B.d. 25th year porosity distribution

Figure 4.4.2B.e. 25th year water saturation distribution

Figure 4.4.2B.f. 25th year gas saturation distribution
4.4.3 Five vertical production wells with uniform permeability

**Figure 4.4.3A** Effect of Bottom-hole Pressure (BHP 2500KPa)

- **Figure 4.4.3A.a.** 1st year pressure distribution
- **Figure 4.4.3A.b.** 1st year temperature distribution
- **Figure 4.4.3A.c.** 11th year pressure distribution
- **Figure 4.4.3A.d.** 11th year temperature distribution
- **Figure 4.4.3A.e.** 11th year hydrate distribution
- **Figure 4.4.3A.f.** 11th year porosity distribution
Figure 4.4.3A.g. 11th year water saturation distribution

Figure 4.4.3A.h. 11th year gas saturation distribution

Figure 4.4.3.C Production with increased bottom-hole pressure

Figure 4.4.3C.a. 11th year pressure distribution

Figure 4.4.3C.b. 11th year temperature distribution

Figure 4.4.3C.c. 11th year hydrate distribution

Figure 4.4.3C.d. 11th year porosity distribution
Figure 4.4.3C.e. 11th year water saturation distribution

Figure 4.4.3C.f. 11th year gas saturation distribution
Appendix E

Governing equations

The basic hydrate dissociation equation is given by:

\[ CH_4 \cdot N_h H_2 O_{(solid)} \leftrightarrow CH_4(gas) + N_h H_2 O_{(liquid/ice)} \]

Where \( N_h \) is the hydration number.

This governing equation of the simulator describes the decomposition of gas-hydrate. Kim et al. (1987) performed the first quantitative study of gas hydrate decomposition kinetics. They proposed the following equation for the rate of dissociation of gas hydrate.

\[ \frac{dc_h}{dt} = k_d A_d (P_e - P_g) \]

where, \( C_h \) is the hydrate concentration, \( k_d \) is the decomposing rate constant, \( A_d \) is the hydrate decomposing area occupied by water and gas in porous medium, \( P_e \) is the liquid water-hydrate-vapor (\( Lw-H-V \)) equilibrium pressure and \( P_g \) is the gas pressure in bulk.

The decomposition rate constant \( k_d \) is defined as,

\[ k_d = k_d^o \exp \left( -\frac{E}{RT} \right) \]

Where, \( k_d^o \) is the intrinsic decomposition rate constant, \( E \) is the activation energy and \( R \) is the universal gas constant.

Substituting eqn(1) into eqn(2),

\[ \frac{dc_h}{dt} = k_d^o A_{dec} (P_e - P_g) \exp \left( -\frac{\Delta E}{RT} \right) \]

Eqn (3) can be re-written as,
\[
\frac{dc_h}{dt} = k_d^o A_{dec} P_e \left( 1 - \frac{P_g}{P_e} \right) \exp \left( -\frac{\Delta E}{RT} \right) \tag{4}
\]

Where, the ratio of \(P_e/P_g\) is substituted for K-value (partition coefficient), as shown in the equation below;

\[
\frac{dc_h}{dt} = k_d^o A_{dec} P_e \left( 1 - \frac{1}{K} \right) \exp \left( -\frac{\Delta E}{RT} \right) \tag{5}
\]

One of the problems is that the decomposition surface area \(A_{dec}\) is not a constant. If hydrate exists at saturation \(S_h\) in a porous medium and consists of spherical particles having a surface area of \(A_{hs}\), then the effective decomposing area of hydrate per unit volume of the porous medium can be approximated as,

\[
A_{dec} = \phi^2 A_{hs} S_w S_h
\]

Using this approximation of \(A_{dec}\), we can rewrite eqn (5) as,

Partial pressure \((P_e)\) is denoted in the gas phase as \(y_iP_g\).

\[
\frac{dc_h}{dt_{form}} = \frac{k_d^o A_{hs}}{\rho_h \rho_w} \exp \left( -\frac{\Delta E}{RT} \right) \left( \phi S_w \rho_w \right) \left( \phi S_h \rho_h \right) y_i P_g \left( 1 - \frac{1}{K(P,T)} \right) \tag{6}
\]

Hydrate decomposition and formation rates can be written as;

\[
\frac{dc_h}{dt_{form}} = A \exp \left( -\frac{\Delta E}{RT} \right) \left( \phi S_w \rho_w \right) \left( \phi S_h \rho_h \right) y_i P_g \left( 1 - \frac{1}{K(P,T)} \right), \text{ and}
\]

\[
\frac{dc_h}{dt_{decay}} = B \left( 1 + \phi S_h \right) \exp \left( -\frac{\Delta E}{RT} \right) \left( \phi S_w \rho_w \right) \left( \frac{1}{K(P,T)} - 1 \right) \tag{7}
\]

Where; \(1 - \frac{1}{K(P,T)}\) and \(\frac{1}{K(P,T)} - 1\), are the driving forces for hydrate decomposition and formation respectively.

A&B is the kinetic rate constants or mass transfer coefficients, or frequency factors for hydrate decomposition and formation respectively.

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Te constants can be defined as,

\[ A = \frac{k_d A_{HS}}{\rho_w \rho_H} \text{ (gmole/(day.KPa.m²))} \quad \& \quad B = \frac{k_f A_{HS}}{\rho_w} \text{ (gmole/(day.KPa.m²))} \]

\( k_d \) & \( k_f \), are the hydrate intrinsic decomposition, and formation rate constants, and \( A_{HS} \) is the specific area of the hydrate particles.

**Estimate of Gas initially in place and Water**

Calculation of the initial amount of methane gas in place. All the gas that is initially in place is present in the form of methane hydrate.

\[ GIIP = V_B \phi S_h FVF \]

\( V_B = 620 \times 840 \times 100 = 5.2080 \times 10^7 \text{[m}^3\text{]} \]

\[ GIIP = 5.2080 \times 10^7 \times 0.35 \times 0.5 \times 164 = 1.495 \times 10^9 \text{[m}^3\text{]} \]

Equation \( x \) can also be used to calculate the total amount of water in place.

Amount of water in hydrate phase = \( 5.2080 \times 10^7 \times 0.35 \times 0.5 \times 0.8 = 7.2912 \times 10^6 \text{[m}^3\text{]} \)

Amount of water in water saturation phase = \( 5.2080 \times 10^7 \times 0.35 \times 0.5 = 9.1141 \times 10^6 \text{[m}^3\text{]} \)

Total amount of water in place = \((7.2912 + 9.1141) \times 10^6 \text{[m}^3\text{]} = 1.64052 \times 10^7 \text{[m}^3\text{]} \)

Where,

\( GIIP = \text{Gas initially in place} \text{[m}^3\text{]} \)

\( V_B = \text{Bulk rock volume} \text{[m}^3\text{]} \)

\( \phi = \text{Porosity [-]} \)

\( S_h = \text{Hydrate saturation [-]} \)

\( FVF = \text{Formation volume factor between methane and methane} \text{[m}^3/ \text{m}^3\text{]} \)
Nomenclature

$A_d$ hydrate decomposition surface area per unit volume (m$^2$/m$^3$)  
$A_{HS}$ specific area of hydrate particles (m$^2$/m$^3$)  
$A_f$ hydrate accumulation area occupied by water and gas in the porous medium  
$C_h$ hydrate concentration per unit volume (gmole/m$^3$)  
$C_{pg}$ gas phase heat capacity (J/mole K)  
$E$ activation energy (J/mole)  
$H$ enthalpy (J/mole)  
$H_{vap}$ vaporization enthalpy (J/mole)  
$K$ hydrate equilibrium or stability value ($=pe/pg$)  
$K_0$ intrinsic kinetic rate constant (gmole/m$^3$ KPa day)  
$K_0$ absolute permeability (mD)  
$Mm$ molecular mass (kg/mole)  
$n$ hydration number structure I hydrate (5.75-6.0)  
$pe$ phase equilibrium pressure (KPa)  
$pg$ gas phase pressure (KPa)  
$R$ universal gas constant (J/mole K)  
$S_{wr}$ residual water saturation  
$S_{gr}$ residual gas saturation  
$\phi$ porosity (-)  
$\phi_f$ fluid porosity (-)  
$\rho$ mole density (gmole/m$^3$)  
$A$ decomposition rate constant (gmole/m$^3$)$^{-1}$/KPa .day  
$B$ formation rate constant (KPa)$^{-1}$ (day)$^{-1}$  
$G_p$ Cumulative gas produced (m$^3$)  
$G_t$ Gas initially in place (m$^3$)