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Norwegian University of
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Evaluation of Methods for Drilling and Production of Hydrate Formations

Anders Gundersen

Petroleum Geoscience and Engineering

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Supervisor: Sigbjørn Sangesland, IPT

Norwegian University of Science and Technology

Department of Petroleum Engineering and Applied Geophysics

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I hereby certify that this work is solely my own.

June 10th, 2013
Trondheim, Norway

Anders Gundersen

Everybody knows that a reservoir can't hang in a well

- Cor J. Kenter

Studieprogram i Geofag og Petroleumsteknologi
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Institutt for petroleumsteknologi og anvendt geofysikk
Department of Petroleum Engineering and Applied Geophysics

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Utfyllende tekst/Extended text:
Background:

Naturally occurring gas hydrate has, up until recently, been primarily viewed as either a drilling related geohazard or an obstacle to the transportation of natural gas. However, it is now being increasingly viewed as a potential energy resource for the 21st century. The potentially vast amount of methane locked in this resource has spurred a marked acceleration into the research and development over the last decade. And although commercial gas production has not yet been achieved, there are many research programs worldwide aimed at achieving this objective, funded by both governmental organizations and private companies. One of the keys to unlocking the potential of this resource is to overcome the unique challenges related to drilling production wells in hydrate bearing formations, and to produce natural gas from these reservoirs.

Task:

- 1) Explain the composition, properties, characteristics, stability, geographic occurrence, global distribution, volume estimates, recoverability and types of occurrences of gas-in-place locked in gas hydrates.
- 2) Describe and evaluate the available methods and technologies for drilling through formations containing gas hydrates and make a recommendation of the best suited method or technology.
- 3) Perform a Matlab simulation of the annulus temperature profile in a well during drilling into a formation containing gas hydrates. The focus in this model will be on determining the required inlet mud temperature, which will prevent or strongly limit gas hydrate dissociation in the wellbore.
- 4) Describe and evaluate the available methods and technologies for gas production from formations containing gas hydrates and make a recommendation of the best suited method or technology.

Supervisor *Sigbjørn Sangesland*

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Summary

Interest in gas hydrates as an energy resource has grown continuously over the last decades, and it has significantly increased since the beginning of the last decade. Much of the interest has come from countries with limited access to conventional hydrocarbon resources, and/or with a strategic interest in developing alternative hydrocarbon resources. Although the gas-in-place volume estimates of gas locked in gas hydrates remains uncertain, they indicate a vast resource volume. These vast resource volumes, combined with the environmental desirability of gas compared to other hydrocarbon fuels and the growing worldwide energy demand, leads to the conclusion that the potential of gas hydrate as an energy resource is very large. However, gas production from gas hydrate reservoirs do not yet exist on a commercial scale as a consequence of the unique challenges associated with drilling and production from these reservoirs.

The goal of this thesis has been to investigate and understand these unique drilling- and production related challenges, with an emphasis on the drilling related challenges, to suggest and evaluate possible methods and technologies that could solve these challenges, and to make recommendations of how these challenges can be overcome using existing methods and technologies. Background information concerning the properties and characteristics of gas hydrates and the classification of different types of gas hydrate reservoirs have been covered to provide a base from which the drilling and production related challenges could be discussed. A Matlab model has also been developed and simulated to investigate the annulus temperature profile during drilling at a specific depth, as keeping a low temperature in the annulus was found to be an important factor in reducing the drilling related challenges.

The first of the two main findings in this thesis is that production wells can be drilled safely and effectively in formations containing gas hydrates by using a combination of different existing technologies. This involves drilling with managed pressure drilling in combination with other methods. These methods are: casing while drilling, where technically and economically possible; surface mud cooling, to reduce the temperature in the annulus and prevent dissociation of gas hydrates in the formation and cuttings; drilling with high circulation rate; and insulated equipment, if necessary. The second major finding is that the recommended production strategy for all three classes of gas hydrate reservoirs is depressurization combined with thermal stimulation

in the near wellbore area. Thermal stimulation is important to prevent the formation of ice and secondary gas hydrates that has a disadvantageous effect on the near wellbore permeability and, consequentially, the gas production rate and cumulative gas production volume. Suggested further work includes:

- Determining experimentally the gas hydrate dissociation rate as a function of P&T that can be used to estimate the free gas volume in the annulus during drilling
- Continued investigation into methods and technologies for reducing drilling related challenges in gas hydrate formations, for instance, the potential of surface mud cooling on annulus temperature distribution
- Improvements of the Matlab model and program, for instance including the effect of a riser, variable formation temperature, radiation heat transfer, and heat generation due to friction between the drill string and the formation

Sammendrag

Interessen for gasshydrater som en energikilde har vokst kontinuerlig over de siste tiårene, og har økt markant siden begynnelsen av forrige tiår. Mye av interessen har kommet fra land som har begrenset tilgang til konvensjonelle hydrokarbonressurser, og/eller som har strategiske interesser i å utvikle alternative hydrokarbonressurser. Selv om ressursestimatene for gass fanget i gasshydrater er usikkert, indikerer de at det er en veldig stor ressurs. Dette store ressursvolumet, kombinert med miljøfordelen gass har over andre hydrokarbonressurser og det økende globale energibehovet, fører til konklusjonen om at potensialet for gasshydrater som en energikilde er svært stort. Allikevel finnes det ikke gassproduksjon fra gasshydratreservoarer på kommersiell skala enda. Det er en konsekvens av de unike bore- og produksjonsutfordringene i disse reservoarene.

Målet med denne oppgaven har vært å undersøke og forstå disse unike bore- og produksjonsrelaterte utfordringene, med fokus på de borerelaterte utfordringene, og å foreslå og evaluere potensielle metoder og teknologier som kan løse disse utfordringene, og å komme med anbefalinger om hvordan disse utfordringene kan løses ved bruk av eksisterende metoder og teknologier. Bakgrunnsinformasjon vedrørende egenskaper og kjennetegn ved gasshydrater og klassifiseringen av de forskjellige typene av gasshydratreservoarer som finnes har også blitt inkludert for å gi et grunnlag som de bore- og produksjonsrelaterte utfordringene kunne bli diskutert på.

En Matlab modell har også blitt utviklet og simulert for å undersøke temperaturprofilen i ringrommet under boring på en spesifikk dybde, ettersom å holde en lav temperatur i ringrommet har blitt funnet å være en viktig faktor i å redusere de borerelaterte utfordringene.

Den første av to hovedfunnene som har blitt gjort i denne oppgaven er at produksjonsbrønner kan bli boret trykt og effektivt i formasjoner som inneholder gasshydrater ved å bruke en kombinasjon av forskjellige eksisterende teknologier. Dette innebærer å bore med ”kontrollert-trykk-boring” i kombinasjon med andre metoder. Disse metodene er: foringsrør under boring, der hvor det er teknisk og økonomisk mulig; overflatenedkjøling av boreslam, for å senke temperaturen i ringrommet og å forhindre dissosiasjon av gasshydratene i formasjonen og i borekaket; boring med høy sirkulasjonsrate; og isolerende utstyr, hvis nødvendig. Den andre av de to hovedfunnene

er at den anbefalte produksjonsstrategien for alle tre typene av gasshydratreservoarer er trykkreduksjon kombinert med termisk stimulering i nær-brønn-området. Termisk stimulering er viktig for å forhindre dannelse av is og sekundære gasshydrater som har en ufordelaktig påvirkning på permeabiliteten i nær-brønn-området, og følgelig, på gassproduksjonsraten og det kumulative gassproduksjonsvolumet. Foreslått videre arbeid inkluderer:

- Eksperimentell bestemmelse av dissosiasjonsraten til gasshydrater som en funksjon av trykk og temperatur som kan bli brukt til å estimere innholdet av fri gass i ringrommet under boring
- Fortsette undersøkelsen av metoder og teknologier som kan brukes for å redusere de borerelaterte utfordringene i gasshydratformasjoner, for eksempel potensialet for overflatenedkjøling av boreslam på temperaturfordelingen i ringrommet
- Forbedringer av Matlab-modellen og programmet, for eksempel inkludere effekten av stigrør, variabel formasjonstemperatur, varmeoverføring ved strålingsenergi og varmegenerering som konsekvens av friksjons mellom borestrengen og formasjonen

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1 Introduction

The easily accessible oil and gas resources have been depleted. To meet the world's increasing energy demands at the same time as oil and gas resources are becoming increasingly difficult to explore, drill and produce economically, the industry is forced to make technological and engineering advancements to not only reduce the cost of current methods, but also to access new resources. A consequence of this has been the industry's enormous investments in unconventional resources, for instance: shale gas and shale oil, tight gas and tight oil, oil sands, coalbed methane and gas hydrates (GHs).

GHs have been viewed with interest during the last decade, primarily by countries with little or no access to conventional hydrocarbons, such as Japan, or for countries with a strategic interest in obtaining additional unconventional hydrocarbon alternatives, such as USA. Based on the magnitude of the reserves and the environmental desirability of gas as a fuel, GH has a very large potential as an energy source. Although commercial gas production does not yet exist, research and development (R&D) into GHs have seen a marked acceleration since the beginning of the last decade. Some of the R&D goals that have been reached so far are (Ohara et al., 2000):

- i. Safe drilling through GH bearing sediments.
- ii. Successful well completion.
- iii. The recovery of core samples.

Naturally occurring GHs are found either on land, in or underneath deep permafrost, or in deep waters offshore at relatively shallow depths below the sea floor in deep ocean sediments. Moridis et al. (2011) states that the predominant component in the majority of natural occurring hydrocarbon GHs is methane (CH₄). Although the in-place estimates of this resource vary widely, if it was possible to economically recover only a small fraction of the conservative estimates, the resource would still be sufficiently large to demand evaluation as a potential energy source. The need for evaluation of this resource is made only clearer when taking into consideration the increasing global energy demand, limited volume of conventional fossil fuels, and the environmental advantage of natural gas over other fossil fuels.

The goals of this master thesis are to describe, analyse and evaluate the existing methods used for drilling and production of hydrate formations (formations containing GHs). The following will be covered to meet these goals:

- Explain the composition, properties, characteristics, stability, geographic occurrence, global distribution, volume estimates, recoverability and types of occurrences of gas-in-place (GIP) locked in GHs.
- Briefly explain the rotary drilling method and how pressure control during drilling is maintained.
- Describe and evaluate the available methods and technologies for drilling in hydrate formations.
- Make a recommendation of the method or technology that is best suited for drilling in hydrate formations.
- Develop a Matlab model and perform a simulation to investigate the annulus temperature profile during drilling at a certain depth when first encountering GHs. The focus of this model will be on determining the required inlet mud temperature that will prevent or strongly limit dissociation of GHs in the wellbore.
- Describe and evaluate the available methods and technologies to produce from hydrate formations.
- Make a recommendation of the method or technology that is best suited for producing from hydrate formations.
- Present a conclusion of the thesis work.

2 Gas Hydrates

In the 19th century, natural gas was often considered to be an unwanted by-product of oil production, and was often burned at the oilfields unless there was a market for it close to the wellhead. This view has changed considerably, and instead of being often regarded as a nuisance, natural gas is now regarded as one of the world's main energy resources. Worldwide demand is increasing; in part due to the recent unpopularity of nuclear energy, the environmental advantage of natural gas over other fossil fuels, and growing worldwide energy demands. Natural gas trapped in gas hydrates (GHs) consists mainly of methane (CH₄), however it usually contains other light hydrocarbons (ethane, propane and butane) and low amounts of H₂S, N₂ and CO₂. A unique characteristic of GHs is the large increase in specific volume during transition from GH to the free state. At standard conditions of pressure and temperature (0°C and 1 bar (STP)), 1 m³ of methane GH disassociates to form 164 m³ of methane gas and 0.8 m³ of water (Figure 1) (Moridis et al., 2011; Kvenvolden, 1993).

Over the past decade, many scientists and researchers have focused their attention towards extracting methane gas from GHs, seeing this as a major future energy resource due to its worldwide distribution, potentially vast volume, and availability at relatively shallow depths. However, there are still many challenges that need to be overcome before large-scale commercial gas production from hydrate formations becomes feasible.

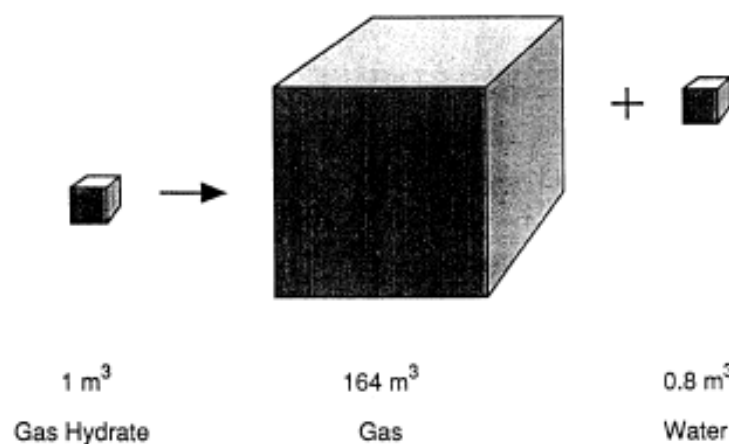


Figure 1: Disassociation of 1 m³ of methane GH at standard temperature and pressure yields 164 Nm³ methane gas and 0.8 m³ water (Kvenvolden, 1993).

2.1 Discovery

The first synthetic GH was created in a physical chemistry laboratory in the early 1800s, and this discovery initiated the first scientific research into the nature of GHs. Although it was not believed to exist in the natural world, creation and testing of GHs continued in laboratory experiments for decades. Non-laboratory created GH was encountered for the first time in the 1930s when it was observed forming in natural gas pipelines, where it in some cases even fully obstructed the gas flow. GHs now became viewed as a flow assurance issue that had to be resolved to ensure safe and efficient gas transport. Scientific research into GHs entered a new phase and was now directed towards developing methods and technology to prevent the formation of GH in pipelines (The Energy Lab, 2011).

The next phase started in the 1960s with world's first discovery of naturally occurring methane GH in subsurface sediments of a gas field in the Western Siberian basin. This was followed by two GH discoveries in the 1970s; one from well samples in the North Slope of Alaska and the other from seafloor sediments collected from the bottom of the Black Sea. The 1980s saw a major GH discovery with the recovery of GH-bearing cores from sediments off the coast of Guatemala, which included a 1-meter sample consisting of nearly pure GH. The accumulation of these discoveries is what caused the shifting view of methane GH from a laboratory curiosity to industrial nuisance to a potentially widespread and vast methane resource (The Energy Lab, 2011).

2.2 Properties and Characteristics

GHs, also referred to as clathrate hydrates, are crystalline solids. Hydrogen bounded water molecules are oriented in cages called polyhedra and make up the “ice-like” crystal lattice, referred to as hosts, which are occupied by natural gas molecules, referred to as guests (Levik, 2000) (Figure 2). In addition to being non-polar, these guests have to be small enough to fit into the cages, and have a diameter no less than about a fraction of 0.76 of the cage diameter. If the diameter of the guest is smaller than that ratio, the attractive forces acting between the guest molecules and host molecules will be insufficient to stabilize the GH (Levik, 2000).

The natural gas guest molecules that occupy the cages in the crystal lattice in most natural occurring GH resources are methane, which means that methane GHs are the predominant type. For the GH structure to be stable, a specific portion of the cages in the clathrate must contain a guest molecule. For methane GHs this portion is 90% or higher (Kvenvolden, 1993). The bond between the water and gas molecules in the crystal lattice is in fact not a chemical bond and only involves van der Waals forces. However, it is still sufficiently strong that the presence of guest molecules inside the ice cages makes the entire structure stable enough at elevated pressures to raises the melting point of ice significantly above 0°C (Khameneh et al., 2012).

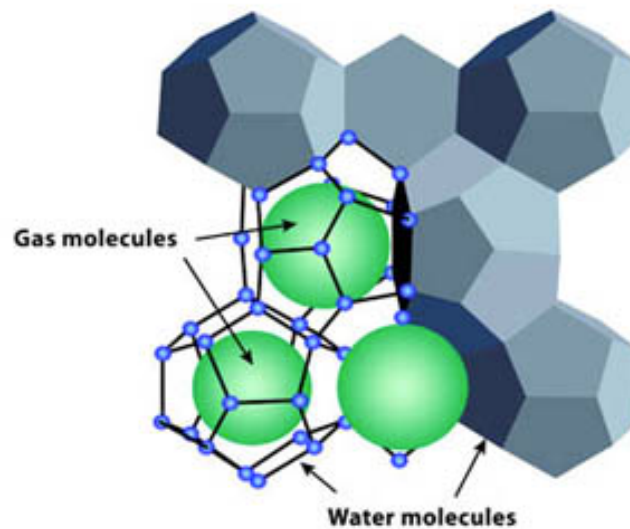


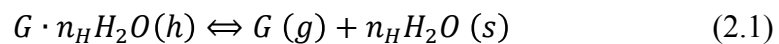
Figure 2: Illustration of the structure of methane GH where the gas molecules are trapped in cages of water molecules (National Oceanography Centre, 2013).

2.3 Formation, Stability, Instability and Dissociation

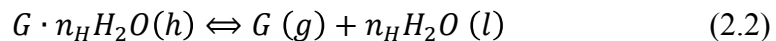
The following factors control the formation of GHs: pressure, temperature, ionic strength of the water and the composition and saturation of the gas mixture (Kvenvolden, 1993). GHs form in any specific high-pressure and low-temperature conditions where water coexists with gas molecules of suitable size and in sufficient volume. The GH formation reactions, which are referred to as exothermic because they release heat, are the reverse of the reactions shown in Equation 2.1 and Equation 2.2.

2.3.1 Instability and the Dissociation Reaction

When GHs are removed from the pressure and temperature (P&T) conditions where they are stable, for instance when they are transported to the surface up the annulus as cuttings during a conventional overbalanced drilling operation and the pressure reduction and temperature increase makes the clathrate structure unstable, or when in the presence of thermodynamic inhibitors, the clathrate structure breaks down and release the gas and water molecules. This process is referred to as dissociation, and the GH is said to dissociate. By igniting the released gas, given it is a hydrocarbon gas, the ice can appear to be on fire. The endothermic reaction, meaning that heat is taken from the surroundings, for a GH with hydration number n_H that dissociates is given by the two general equations:



Equation 2.1: General equation for the GH dissociation reaction at temperatures below 273.15 K (Levik, 2000).



Equation 2.2: General equation for the GH dissociation reaction at temperatures above 273.15 K (Levik, 2000).

Where:

- G is the guest gas
- n_H is the hydration number denoting the number of water molecules in the GH molecule, or the number of free water molecules in the solid (s) or liquid (l) state after dissociation

The hydration number ranges from 5.77 to 7.4 for the crystallization of the most common structure of natural methane GHs, with an average hydration number of $n_H = 6$. For complete hydration $n_H = 5.75$ (Moridis et al., 2011).

The energy required for the dissociation reaction is given by the specific enthalpy of GH dissociation (Δh°_{diss}), and is given in J/mol or J/g. The “mol” in J/mol unit of the Δh°_{diss} means 1 mol of GH with the formula $G \cdot n_H H_2O$, while the “g” in J/g represents 1 gram of GH. The molar mass of a GH is given by the following equation (Levik, 2000):

$$M_{hydrate} = M_G + M_W n_H \quad (2.3)$$

Equation 2.3: Equation that gives the molar mass of a GH (Levik, 2000).

Where:

- M_G is the molar mass of the guest gas
- M_W is the molar mass of water, which is 18 g/mol

The Δh°_{diss} for pure methane is 18.13 kJ/mol for temperatures between 160-210 K, while it is 54.19 kJ/mol for temperatures above 273.15 K. This number is highly dependent on the hydrate number and the amount of free water, and will therefore vary significantly between different types of GHs, and also between different GHs with the same gas composition. In Equation 2.1 the GH dissociates into gas and ice, while in Equation 2.2 it dissociates into gas and liquid water. Because the formation of liquid water requires considerably more energy than the formation of ice, the dissociation enthalpy is considerably higher for temperatures above 273.15 K than for temperatures below 273.15 K. The enthalpy difference between the two reactions is therefore assumed to be the enthalpy of ice melting (Levik, 2000). Free solid or liquid water might also be contained in the GH and melting the free ice to liquid water would require 334 kJ/kg, while freezing the liquid water into solid would release the corresponding amount of heat. The phase transition between the solid and liquid phase of water follows the following reaction:



Equation 2.4: Phase transition of water between the solid (s) and liquid (l) state (Levik, 2000).

2.3.2 Required Heat to Dissociate Methane Gas Hydrates

Since the dissociation reaction for GHs is endothermic, it will absorb heat from its surroundings. A simplified calculation has been undertaken to calculate the energy required to dissociate methane GHs into free gas and water, calculate the energy content of the released methane gas ($164 \text{ Nm}^3_{\text{Methane}}/\text{m}^3_{\text{Methane GH}}$), and to compare the two. The calculation is shown in chapter Appendix A.

The results are that the dissociation of 1 m^3 methane GH requires 393.3 MJ and that the energy content of the methane gas locked in 1 m^3 of methane GH (164 Nm^3) is 6.43 GJ. Dividing the energy provided by burning the methane gas with the dissociation energy yields an energy ratio of 16.35, which means that the energy gained from burning the gas is 16.35 times higher than the energy required to release the same gas volume through dissociation. In other words, the dissociation process requires 6.12% of the energy content in the gas that is released in the same process. The following assumptions and simplifications have been made for the calculation:

- The guest gas consists of 100% methane
- The temperature after the dissociation reaction is above 273.15 K, which means that liquid water is formed. This requires significantly more energy than the dissociation reaction below 273.15 K
- The specific enthalpy of GH dissociation given by Levik (2000), which is 54.19 kJ/mol, is assumed appropriate. So is the hydration number ($n_H = 6$), which is the average hydration number for the most common methane GH type present.
- Density of methane GH is 900 kg/m^3
- The heat of combustion of methane gas is 891 kJ/mol
- Assuming no free water, meaning that there is no water present except the quantity trapped in the GH structure. This assumption has a significant impact on the result due to the high amount of energy required to melt ice into liquid water. The energy gained from burning the GH would be lower compared to the energy required to dissociate the same gas volume if there was free water present

The assumption that the GH contains no free water in either solid or liquid form can be a significant error in the calculations, as the specific enthalpy of GH dissociation is highly dependent on this value. The calculation also does not include heat lost to the surroundings and assumes that 100% of the heat is consumed by the dissociation process.

Assuming that a production well can be drilling through a GH reservoir without dissolving the GHs, this heat is the theoretical minimum heat that must be added to dissolve the GHs in the separation system on the surface to release the gas. Even in this situation, the required heat added to the separation system to dissolve the GHs might be significantly higher due to losses to the surroundings, for example heat losses to the water and mud in the system. While drilling, the necessary dissociation heat could be taken from the surroundings during transportation to the surface, for example from the circulating mud in the annulus, which would mean that the required heat at the surface would be significantly reduced. This would however result in a significant amount of free gas in the wellbore and riser (if drilling offshore). The consequence of this situation is discussed further in chapter 3. The energy ratio given in this section could however be more representative of the situation where gas is being produced from a GH reservoir by thermal stimulation methods, such as hot water or steam (5.1.2).

2.3.3 Gas Hydrate Stability Zone

Several kilometres beneath the surface of the earth and over millions of years, the decay of organic matter have formed natural gas. Two basic mechanisms are known for how parts of this gas have formed GHs. In the first mechanism, some of the gas migrated towards the surface due to its low density, thereby entering P&T conditions favourable to GH formation. The static pore water then interacted with the gas that percolated from hydraulically connected subadjacent zones and formed GHs. In the second mechanism, a solution oversaturated by gas moves to a zone with favourable P&T conditions (higher pressure and/or lower temperature), thus forming GHs (Amodu, 2008).

The specific range of pressure and temperature that allows water molecules to trap the gas molecules in cages and form stable GHs given a sufficient concentration of natural gas is called the Gas Hydrate Stability Zone (GHSZ). Although GHs do not necessarily exist within the GHSZ of an area, they can occur given the right conditions. Below the GHSZ the GHs are unstable and gas and water exists independently. The

depth and width of the GHSZ will be influenced greatly by the geothermal gradient. A high geothermal gradient means that the formation will warm quickly with increasing depth, meaning a lower height of the GHSZ compared to a low geothermal gradient (Thomas, 2001).

In marine environments, depending on the water depth in the area (which determines the pressure) and given a sufficiently low temperature, GH could occur at great depths below the seafloor or just below the seabed (National Oceanography Centre, 2013). During exploration, seismic data is interpreted to infer the occurrence of most oceanic GHs mainly based on the seismic reflection profiles of an anomalous bottom simulation reflection (Kvenvolden, 1993).

Figure 3 illustrates the GHSZ for an offshore location. In this example, even though the GHSZ interval is from roughly 400-1,900 meters depth, GHs only occur in sediments from 1,600-1,900 meters because that is where the concentration of methane is sufficiently high.

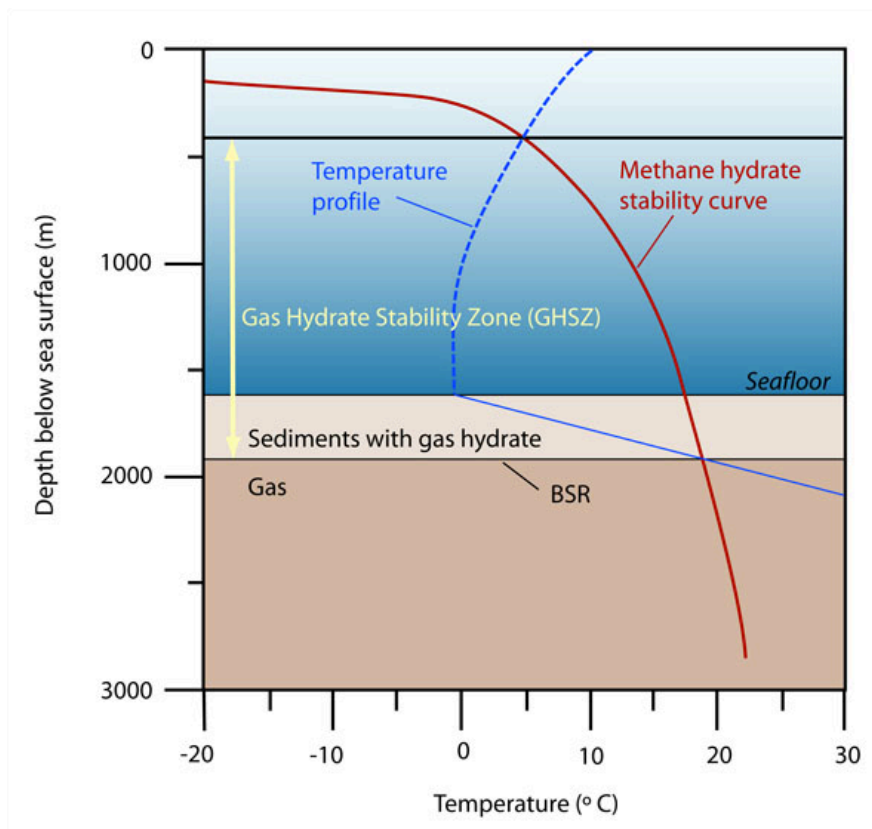


Figure 3: This chart shows the stability zone for GHs in an offshore environment in 1,600 meters water depth, referred to as the GHSZ (National Oceanography Centre, 2013).

2.3.4 Methane Hydrate Phase Diagram

Due to the lack of exact knowledge regarding water and gas composition in sedimentary pores, it is usually difficult to accurately predict the GHSZ, the zone in which naturally occurring GHs are stable, even with detailed knowledge of the P&T regime in an area (Kvenvolden, 1993). To simplify this problem and circumvent the lack of information, it is common to assume that the sedimentary pores contain only pure water and pure methane, thereby enabling the use of pure methane and pure water phase diagrams to estimate the GHSZ. One such pure methane and pure water phase diagram is shown in Figure 4.

Because the pore-pressure increases in rock formations with increasing depth below the surface of the earth or the ocean, depth of burial is sometimes used as a simplification to indirectly represent the fluid pressure on GH phase diagrams by assuming a hydrostatic pore-pressure gradient. In Figure 4, the y-axis shows the depth of burial using depth as an indirect indicator of pressure, increasing from top to bottom. The methane exists as GH in the dotted area (on the lower left) and as free gas in the white area (on the upper right). The arched line between the two areas is the methane GH-gas phase boundary. Above this boundary, the pressure is too low and the temperature is too high for the formation of stable methane GH to occur, and methane can only be present in its gaseous form. Below this boundary, the temperature is sufficiently low and the pressure is sufficiently high to allow methane GH to form and remain stable (The Energy Lab, 2011). The figure shows that adding NaCl to the water or N₂ to the methane shifts the boundary to the left (decreasing the area of the GH stability field), while adding ethane, butane, CO₂, or H₂S to the methane shifts the boundary to the right (increasing the area of the GH stability field).

When utilizing Figure 4 for a permafrost layer located in a continental polar region, with an assumed temperature of -8°C, the GH-gas phase boundary indicates that the upper depth limit for stable methane GHs is close to 150 meters. Above the GHSZ, methane gas is dissolved at concentrations that reduce towards the surface of the sediment. According to the same diagram, in marine sediments offshore where the bottom water temperatures approach 0°C, stable methane GHs can occur in areas where the water depth exceeds 300 meters (where the pressure is roughly 30 bar). The lower limit of the GHSZ is determined by the geothermal gradient. According to the phase diagram, the maximum temperature for GH to occur, even at depths down to 10,000

meters under the surface, is approximately 33°C. For higher temperatures, the methane GHs will dissociate into free methane gas and water. This is the reason why methane GH layers sometimes have an underlying methane gas layer. The maximum lower limit of the GHSZ, according to Kvenvolden (1993), is about 2,000 meters below the solid surface although it is generally much less, depending on the local geothermal gradient. In conclusion, the GHSZ is limited to the shallow part of the geosphere. This means that drilling for GHs generally occur at shallow depths.

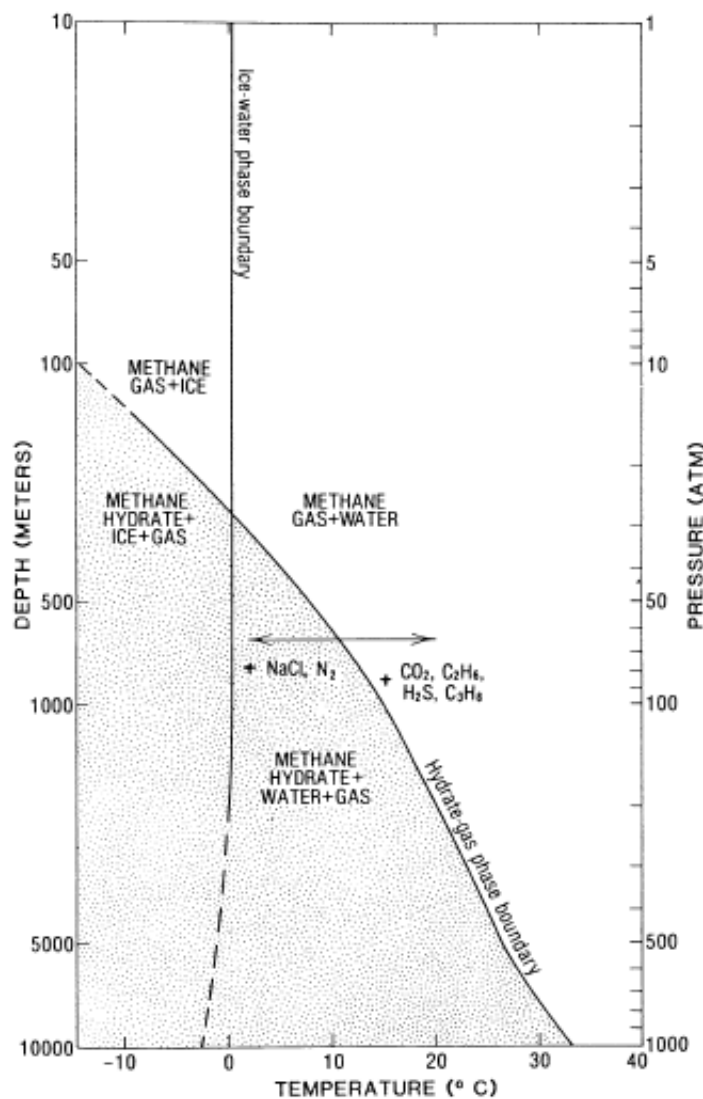


Figure 4: Phase diagram for a pure water and pure methane system (Kvenvolden, 1993).

Figure 5 shows a depth vs. temperature GH phase diagram for an onshore permafrost area that illustrates how changes in the geothermal gradient (which determines the formation temperature increase with depth), depth of permafrost and gas composition can influence the upper and lower limit of the GHSZ. The two laboratory-derived GH stability curves (black and red) represent two different natural gas chemistries. The black curve represents a GH that contains 98% methane, 1.5% ethane and 0.5% propane, while the red curve represents a GH containing 100% methane. The hydrostatic pore-pressure gradient is assumed to be 9.795 kPa/m. The three black dotted lines represent three different cases of depth to the permafrost base: 305 meters, 610 meters and 914 meters. As the example is for an Arctic permafrost area, the mean annual surface temperature is assumed to be -10°C . The temperature at the base of the permafrost is assumed to be 0°C . Three different geothermal gradients are used to project the temperature profiles underneath the permafrost zone: $0.04^{\circ}\text{C}/\text{m}$, $0.032^{\circ}\text{C}/\text{m}$ and $0.02^{\circ}\text{C}/\text{m}$ (Moridis et al., 2011).

The upper and lower limit of the GHSZ in the phase diagram (Figure 5) corresponds to the upper and lower intersection between the GH stability curve and the geothermal gradient. For the 100% methane GH gas composition and a permafrost base at 305 meters, the upper limit (upper intersection with the stability curve) is approximately 250 meters, and the lower limit, assuming a geothermal gradient of $0.04^{\circ}\text{C}/\text{m}$, is approximately 600 meters. In this case, the potential methane GH stability zone is approximately 350 meters thick. With the same gas composition, the permafrost base at 914 meters and a geothermal gradient of $0.02^{\circ}\text{C}/\text{m}$, the upper limit would be approximately 190 meters and the lower limit would be approximately 2,300 meters, resulting in a GHSZ thickness of approximately 2,110 meters. Substituting the GH composition from 100% methane to 98% methane, 1.5% ethane and 0.5% propane, the same as adding small quantities of ethane and propane to the methane mixture, shifts the stability curve to the right resulting in an increased thickness of the GHSZ. This means that calculating the GHSZ of an area with the assumption that the gas composition consists of 100% methane gives a conservative estimate assuming all other variables held constant (Moridis et al., 2011). As seen in Figure 4, the addition of NaCl to the formation water, which increases the pore fluid salinity, or the addition of N_2 to the gas composition, shifts the stability curve to the left thus lowering the temperature at which GHs can form, decreasing the thickness of the GHSZ.

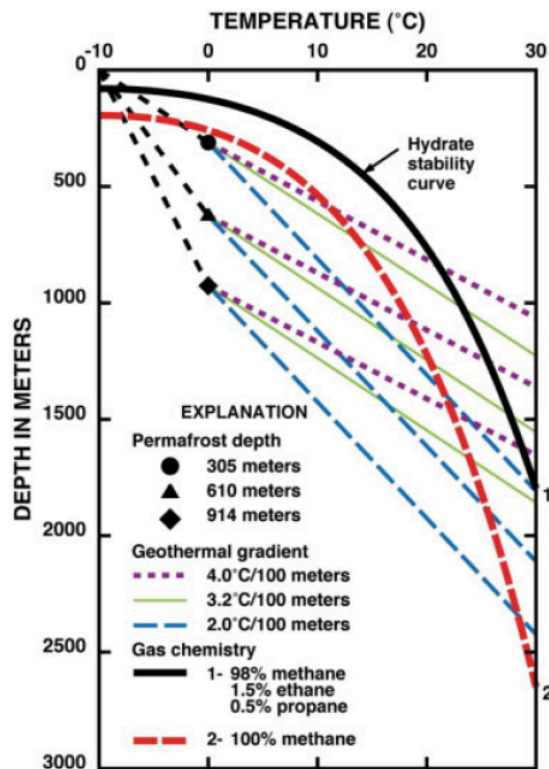


Figure 5: GH phase diagram illustrating how various variations of the gas composition, geothermal gradient, and depth of permafrost influences the GHSZ in a permafrost area (Moridis et al., 2011).

2.4 Geographic Occurrence

According to Kvenvolden (1988), the previously mentioned specific P&T and gas volume requirements limit the natural occurrence of GHs to:

- i. *Oceanic sediment of continental and insular slopes and rises of active and passive margins at water depths greater than 300 meters*
- ii. *Deep-water sediment of inland lakes and seas, also where water depths are greater than 300 meters*
- iii. *Polar sediment of both continents and continental shelves*

This quote states that although GHs occur worldwide, its occurrence is restricted to two geographic regions, which is polar and deep oceanic (Figure 6). The two graphs in Figure 7 exemplifies general examples of the GHSZ in these two different environments, one for the polar region (left graph) and one for the deep oceanic region (right graph).

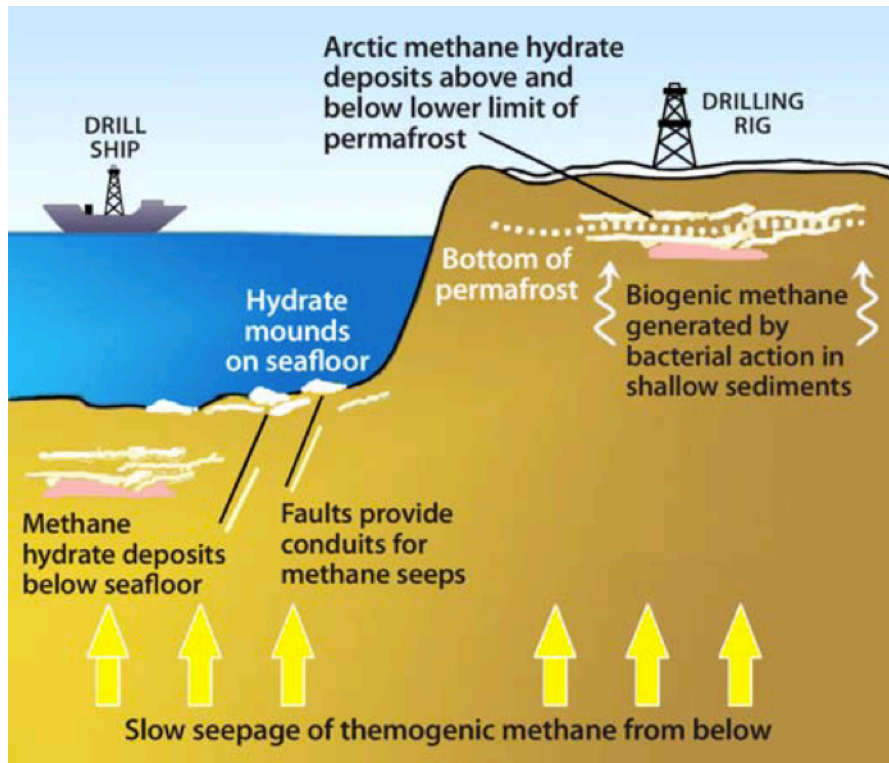


Figure 6: The two geographic regions where GHs occur worldwide: polar and deep oceanic (The Energy Lab, 2011).

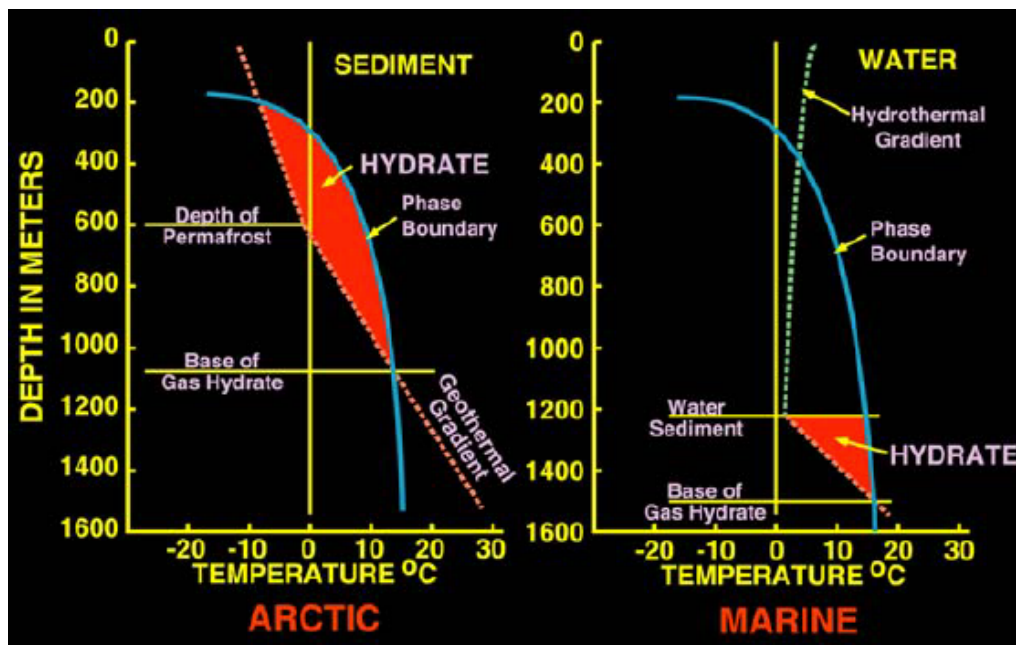


Figure 7: Formation of GHs in specific high-pressure and low-temperature conditions where gas and water is present in permafrost (left graph) and marine sediments (right graph) (Hancock et al., 2010).

2.5 Global Distribution

The earth is comprised of 70% oceans and 7% of permafrost. However, approximately 99% of the total GH resource can be found in oceanic GHs, while the remaining 1% constitutes the permafrost GH reserve. This disproportionately large oceanic volume means that an error of only 1% in the oceanic GH volume estimate would equal the total estimated permafrost GH reserve. Future R&D activity is likely to be primarily directed towards oceanic GHs due to its relative abundance and its proximity to markets such as the energy consuming nations of USA, Japan, India and China. Arctic R&D is however expected to continue due to the cost advantage of running long-term field programs in this area compared to deep water (Moridis et al., 2009).

Figure 8 shows sites across the world where the presence of GHs have been either confirmed by recovery of samples or inferred from: geophysical signatures from bottom simulation reflections, decrease in pore water salinity, well logs or slumps/pockmarks (Sloan and Koh, 2008). This current database is dwarfed when compared to the massive database on conventional oil and gas reservoirs or the much large database on unconventional resources. Due to the limited data currently available, it is clear that considerable efforts must be undertaken to further explore the global distribution of GHs.

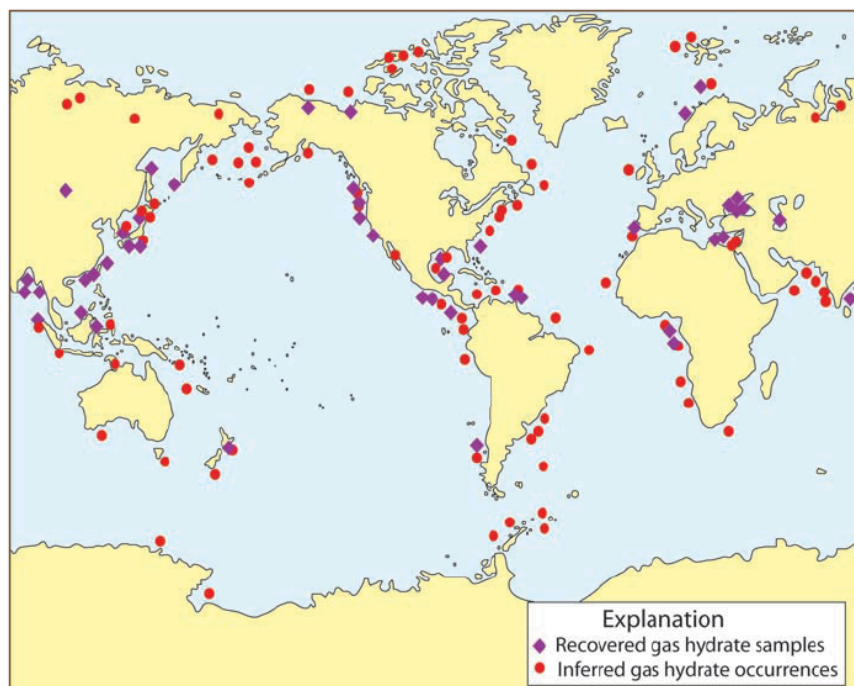


Figure 8: Worldwide recovered and inferred GH occurrences (The Energy Lab, 2011).

2.6 Volume Estimates

As previously mentioned, the GHSZ is the part of earth's crust within which, due to the pressure and temperature regime, GHs are stable and can exist. Early estimates of natural gas locked in GHs used this zone as a basis when modelling and calculating estimates of the total gas-in-place (GIP). Over the last 30 years this model was improved upon several times to include additional variables and increased complexity, and has been used to come up with volume estimates. Extrapolating relatively few but fairly well known localized geological data to a global level has resulted in additional estimates, although these are fairly speculative.

However, the estimates have not converged and still remain highly uncertain (Figure 9). From 2000-2010 they varied by more than three orders of magnitude, from $0.2 \cdot 10^{15} \text{ Nm}^3$ to as high as $120 \cdot 10^{15} \text{ Nm}^3$. In 2008, after reviewing earlier estimates, Boswell et al. hypothesized that a reasonable figure would be approximately $20 \cdot 10^{15} \text{ Nm}^3$ given the existing state of knowledge, an estimate which had been originally presented in 1988 (shown as a red dot on Figure 9) (Boswell et al., 2008).

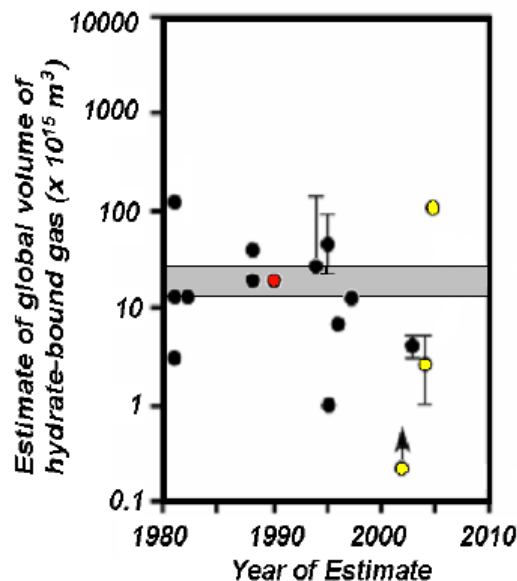


Figure 9: Estimates made from 1980-2010 of the volume of methane (the main gas component in naturally occurring GHs) at STP trapped in global marine GHs. The yellow dots shows the three most recent estimates (Boswell et al., 2008).

It is important to point out that these estimates, for GIP locked in GHs, are neither well defined nor highly certain, and even though even the most conservative estimates suggest vast resources locked in GHs, this does not provide any information concerning the amount that can actually be economically recovered in the near future with current

and expected technologies, market conditions and environmental regulations (Boswell et al., 2008). Considerable R&D investments and efforts are required to decrease the uncertainty of these estimates, which is expected to decline over time with the evolving understanding of GHs (Figure 10).

2.7 Recoverability

The recoverability ratio (RR) depends on the resource in question, and is generally high for conventional resources. The technology to produce from conventional gas resources is mature, and consequently the technically-recoverable resource (TRR) is a high percentage of the total GIP. The economically-recoverable resource (ERR), which is the fraction of the resource that can be produced under current economic conditions, is generally quite high as well for such conventional resources. The TRR is much lower for unconventional resource where it is technically more challenging to recover the resources, and this also leads to a lower ERR. Current information about the TRR for GHs is scarce, although it would seem realistic to assume them to be very low. However, as for other resources, the TRR is expected to increase as technology advances, and knowledge and experience is accumulated (Figure 10). It is also likely that the TRR will vary depending on the different subcategories of the GH resource in question. The ERR is expected to increase as the TRR increases (Boswell et al., 2008).

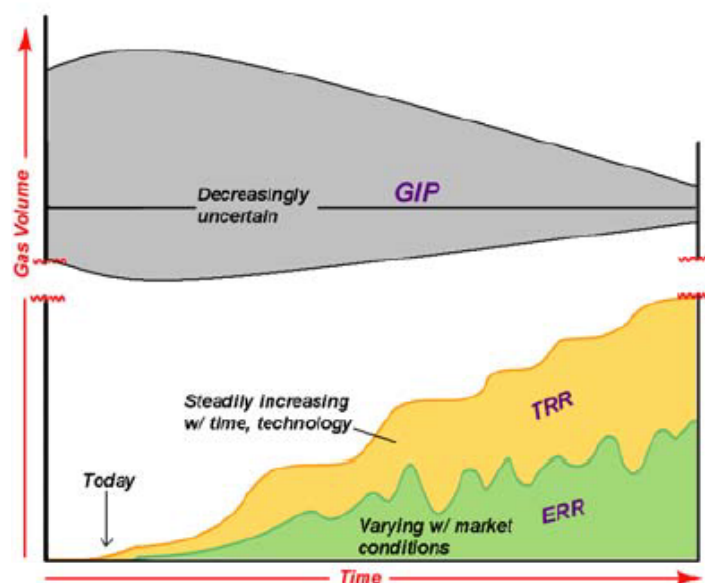


Figure 10: This illustration shows how the certainty of GIP, the TRR and the ERR increases over time with evolving understanding (Boswell et al., 2008).

2.8 The Recoverability of Different Types of Gas Hydrate Occurrences

For the commercial production of any resource, the most favourable locations will be in areas where the resource has the highest concentration, can be easily and economically extracted from the deposits or sediments the resource is contained within, and is close to the market of the resource or existing transportation infrastructure. These requirements would in large parts be fulfilled by a high-porosity and high-permeability reservoir with a high GH concentration (above 50% of the pore volume) located close to existing infrastructure and/or markets, although other factors will also have to be considered (Boswell et al., 2008). It is believed that future attempts to produce gas from GHs will be mainly focused on such locations.

Many different types of GH occurrences exist due to the different types of geological settings that can lead to the formation of GHs, (Moridis et al., 2009). Boswell and Collett (2006) divided the GH resources into 6 different resource categories called tiers, based on the relative likelihood for future production from each resource category and presented them in a GH resource pyramid (Figure 11). Each of the tiers in the GH resource pyramid contains the following information: reservoir type, gas recoverability (decreasing from top to bottom) and estimated total GIP (increasing from top to bottom). The most technically challenging resources to extract are at the bottom of the pyramid, while those that are considered to be the easiest to recover lie at the top. However, it is important to note that each of these deposit types has its own unique set of challenges when it comes to gas extraction. From top to bottom, the tiers and their descriptions are (Moridis et al., 2009):

1. Arctic sandstones under existing infrastructure
2. Arctic sandstones away from infrastructure
3. Deep-water sandstones
4. Non-sandstone marine reservoirs with permeability
5. Massive surficial and shallow nodular GH
6. Marine reservoirs with limited permeability

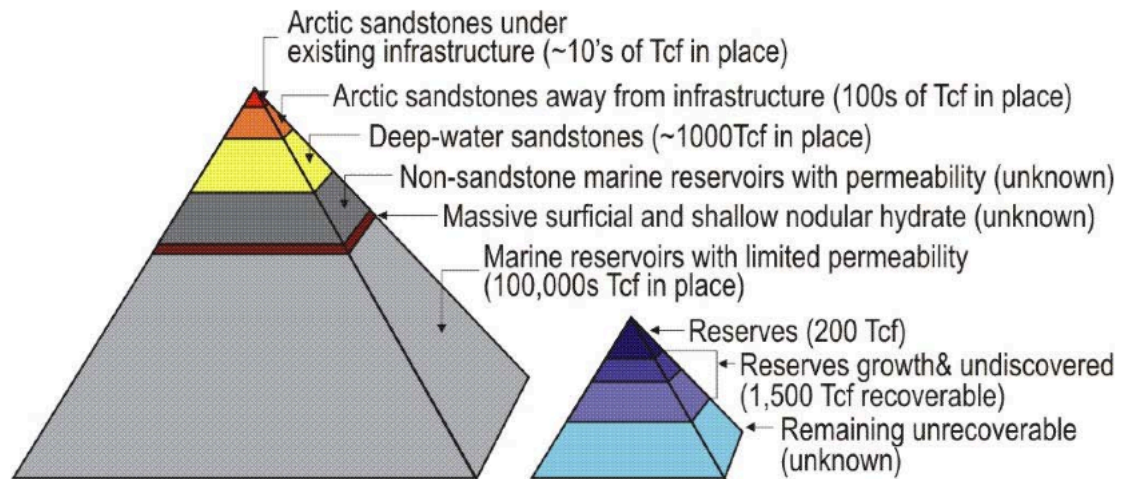


Figure 11: The pyramid to the left is the GH resource pyramid. It is divided into sections that show the relative resource volumes of each subcategory of the GH resource. The right pyramid represents the volume of gas resources from all non-GH resources (Boswell and Collett, 2006).

2.8.1 Arctic Sandstones Under Existing Infrastructure

These reservoirs have high GH concentration within high quality reservoir and are located close to existing infrastructure.

2.8.2 Arctic Sandstones Away From Infrastructure

These reservoirs have high GH concentration within high quality reservoir but are located far from existing infrastructure.

2.8.3 Deep-Water Sandstones

These reservoirs have moderate to high GH concentration within high quality oceanic sandstone. Due to the high cost of operating in deep waters, the most promising deposits are those found in the Gulf of Mexico close to existing oil and gas production infrastructure.

2.8.4 Non-Sandstone Marine Reservoirs With Permeability

Even though it is thought to contain massive GH deposits, production from this fourth tier is considered to required major technological advancements due to low matrix permeability, formation integrity issues and well stability issues. The main focus is on

fractured deposits containing elevated GH concentrations enclosed in fine-grained shales and muds.

2.8.5 Massive Surficial and Shallow Nodular Gas Hydrate

This resource consists of GH piles of limited extent at or near the seafloor. Extraction is not possible using conventional well technology due to the lack of an impermeable overburden above the GH resource and the shallow depth below the ocean floor. Environmental disturbance of sensitive seafloor ecosystems is also an issue.

2.8.6 Marine Reservoirs With Limited Permeability

Vast volumes of fine-grained sediments with low GH concentration, on average about 2-4%, characterize this resource. Although this tier is believed to contain the majority of the worlds GH resource, economical recovery of this resource seems very unlikely with current technology.

2.9 Focus of Future Research and Development

To summarize, the GH deposits that are most likely to be produced are those deposits containing high concentrations of GH in high-permeability host rock in good quality reservoirs that are located close to existing infrastructure. For commercial gas production to occur from GH deposits, two challenges must be overcome. First, the extent of Arctic and oceanic GH in sand reservoirs must be more precisely determined, which will lead to identification of promising deposits. Second, studies must be undertaken to show that the production rates achieved from such deposits will enable economical gas production from high cost Arctic or deep-water resources. Only then will commercial gas production from GHs occur.

Extensive and continuous R&D will be required to gain understanding of which exploration, drilling and production methods and technologies that will be best suited for a particular type of GH deposit. The next two chapters will concern drilling production wells and producing gas from GH reservoirs. They will also include an evaluation of drilling and production methods for GH reservoirs (The Energy Lab, 2011).

3 Evaluation of Methods and Technologies for Drilling Through Hydrate Formations

This chapter includes an evaluation of methods and technologies for drilling through hydrate formations (formations containing GHs), also referred to as hydrate bearing sediments (HBSs). It first begins with a brief description of rotary drilling and pressure control, overbalanced drilling (OBD) and pressure control and kick handling with special emphasis on gas kicks, so as to highlight the difference from the other types of drilling methods that will be presented subsequently, as well as to provide a better understand of how GHs can present a risk to drilling operations. This introductory background is followed by a presentation of the unique challenges encountered when drilling through hydrate formations, a description and evaluation of the most suitable drilling techniques and a recommendation of the best suited drilling technique, followed by a description of different technologies that can reduce the challenges faced when drilling through hydrate formations.

3.1 Rotary Drilling

Rotary drilling involves using an axially loaded rotating drill bit attached to the end of a long string of connected hollow pipes to subject the rock formation to mechanical forces thus breaking apart the rocks and penetrating into the earths crust. The drilling fluid, referred to as mud, is either oil- or water based and is mixed with weighted materials (such as bentonite, barite or salt) and different types of chemicals to give it the desired density and rheological properties. The most important functions of the mud is to cool and lubricate the drill bit and drill string, clean cuttings away from the drill bit and transport them to the surface, maintain a stable borehole wall, control the downhole pressure thus avoiding influx of formation fluids, and suspend mud additives and cuttings when the circulation is interrupted. After being pumped down the drill string, the return mud flows up to the surface through the annulus, which is the space between the drill string and the wellbore wall or the space between the drill pipe and the casing. When the mud reaches the surface it goes through a cleaning process that removes rock particles before it is pumped back down into the well through the drill string.

3.1.1 Pressure Control During Rotary Drilling

Rotary drilling in the oil industry generally uses a fluid column in the well to control the pressure. The pressure at any height (or depth) in a circulated fluid column is given by the following equation:

$$\begin{aligned} P &= P_{Top} + \Delta P_{hydrostatic} + \Delta P_{friction} \\ &= P_{Top} + \rho gh + \Delta P_{friction} \end{aligned} \quad (3.1)$$

Equation 3.1: Equation controlling the pressure in a circulated fluid column. In a static fluid column the friction term disappears (Eck-Olsen et al., 2011).

Where:

- P_{Top} is the top column pressure (the pressure that is exerted on top of the fluid column that is added to the hydrostatic pressure) [Pa]
- $\Delta P_{hydrostatic}$ is the pressure exerted by the static fluid column (hydrostatic pressure) [Pa]
- $\Delta P_{friction}$ is the annulus frictional pressure caused by friction loss in the annulus during circulation of the drilling fluid, also referred to as the flow friction [Pa]
- ρ is the density of the fluid, or average density of the fluids in the column [kg/m³]
- g is the gravitational constant [m/s²]
- h is the height (or depth) of the fluid column [m]

According to Equation 3.1, the pressure in a circulated fluid column can be increased by increasing the density of the fluid (Figure 12), height of the fluid column, pressure exerted on top of the fluid column (Figure 13), or flow friction. In a static fluid column, the flow friction term drops out of the equation.

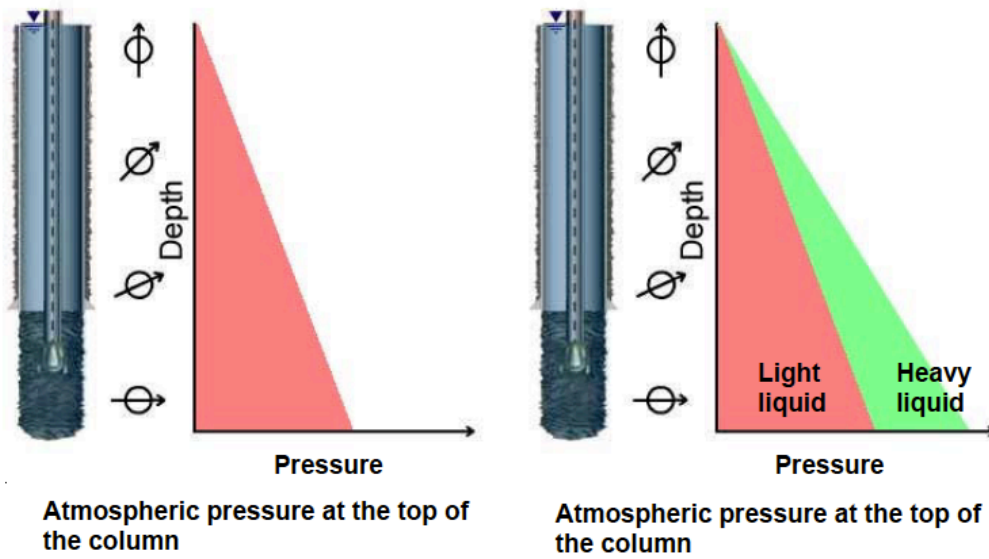


Figure 12: The graph to the left shows that the pressure increases with increased depth. The graph to the right shows that the pressure increases with increased density of the fluid (Eck-Olsen et al, 2011).

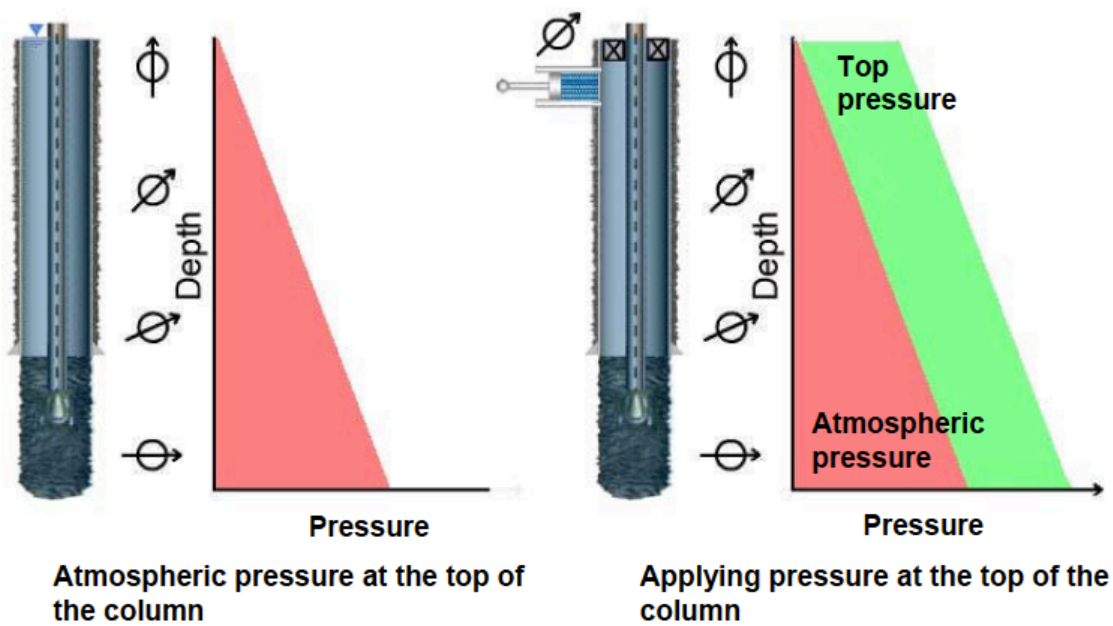


Figure 13: The figure to the right shows that increasing the top column pressure, which is the pressure on top of the fluid column, increases the pressure throughout the fluid column by the same amount (Eck-Olsen et al., 2011).

3.2 Conventional Overbalanced Drilling

OBD involves keeping the pressure at the bottom of the fluid column, the bottomhole pressure (BHP), in the wellbore annulus above the pore pressure of the formation (formation pressure), thus preventing the influx of mobile formation or reservoir fluids into the wellbore (Figure 14).

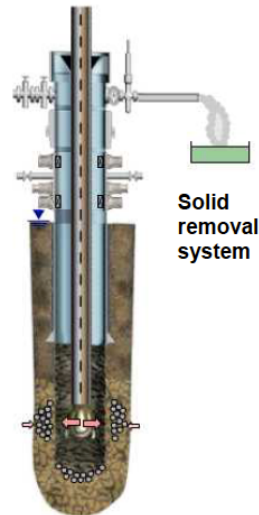


Figure 14: During OBD the pressure at the bottom of the fluid column in the wellbore annulus is kept above the formation pressure (Eck-Olsen et al., 2011).

3.2.1 Pressure Control During Overbalanced Drilling

This overbalanced situation is maintained by adjusting the density of the mud, referred to as the mud weight. Unless a loss of mud or an influx of formation fluids occurs, then the top of the fluid column is fixed at the rotary kelly bushing at the drill floor while the lower level of the fluid column is fixed at the true vertical depth (TVD) of the well. The fluid column can therefore not actively contribute to changing the wellbore pressure during OBD. Neither can the top column pressure, which is atmospheric during normal OBD operations, because the circulation system is open to the atmosphere. And since the flow friction in the annulus during circulation is relatively small, the hydrostatic pressure is what dominates the control of the wellbore pressure during OBD (Eck-Olsen et al., 2011).

The higher pressure in the wellbore relative to the formation results in small amounts of mud leaking into permeable rock formations. The suspended particles in the mud are filtered out by the formation and are deposited on the wellbore wall. Over time this build up of solids against the borehole wall forms a barrier, referred to as a “mud

cake”, that acts to restrict further leakage of drilling mud into the formation, thus limiting the mud loss. This overbalanced situation allows for normal drilling activities to be performed such as circulating out cuttings, drilling, lowering the drill string into the well (tripping-in), hoisting the drill string out the well (tripping-out) and setting casings (Skalle, 2012).

3.2.2 Well Control During Overbalanced Drilling

If the pressure in the wellbore, which is continuously measured at the surface, for some reason drops below the formation pressure of a permeable formation, this will cause formation fluids to flow into the well. The formation fluids entering the wellbore are referred to as an influx. Any incompressible influx volume entering the wellbore, such as salt water and oil, will displace a corresponding amount of drilling mud from the well, which will cause the BHP to decrease since the density of the influx is lower than that of the displaced drilling mud while still occupying the same volume. An influx of gas, which is compressible, will behave very differently during a well control situation than an influx of salt water or oil, and is more challenging to control. This is discussed in detail in section 3.2.2.2. The four most frequent situations leading to a kick, slightly modified from Skalle (2012), are:

1. Mud density is too low due to “gas cut”, “salt water cut” or “oil cut” in the mud or due to encountering formations with higher pressure than the current hydrostatic pressure in the well
2. Mud level in the annulus is lowered due to lost circulation (for example encountering thief zones) or removal of drill pipes from the well during tripping-out
3. Well pressure is decreased due to a suction pressure (swab pressure) that arises in the well when anything in a hole such as drill string, logging tool or completion sting are pulled out of the well
4. Drilling into neighbouring producing wells (occurring very rarely)

Depending on the fluid type of the small influx entering the wellbore from the formation, it is referred to as “gas cut”, “salt water cut” or “oil cut”. If the influx volume is small, then only a slight decrease in the mud weight will be observed as it mixes with the continuously circulating mud. In a situation where a large influx volume is encountered, for example when drilling into a zone with a significantly higher pressure than the BHP, the high-pressure influx will enter the annulus and significantly increase the velocity of the mud returning to the surface. This situation, where a large unwanted influx enters the wellbore and leads to an observable increase in the mud pit volume, is referred to as a “kick”. It is called a kick because the influx entering the well results in specific flow behaviour at the surface where some of the mud is literally “kicked” out of the well. The increased mud return rate, in this situation, will be observed at the surface and compared with the rate that drilling mud is pumped down the drill string, which depends on the pump speed and the mud volume of each piston stroke. If the rate that mud is pumped down the well is the same before and after the large influx was encountered, there will be an observable increase in the mud pit volume at the surface. The mud pits can typically hold around 100 m^3 , so several thousand liters of mud must be displaced from the well before a noticeable difference is observed (Skalle, 2012). Figure 15 shows how the higher pore pressure results in formation fluids entering the wellbore. If the correct actions are not taken quickly, a kick can in the worst-case lead to an uncontrolled flow of formation fluids into the wellbore, referred to as a blowout, which can have catastrophic consequences for equipment, installations, the environment and safety of personnel (Skalle, 2012).

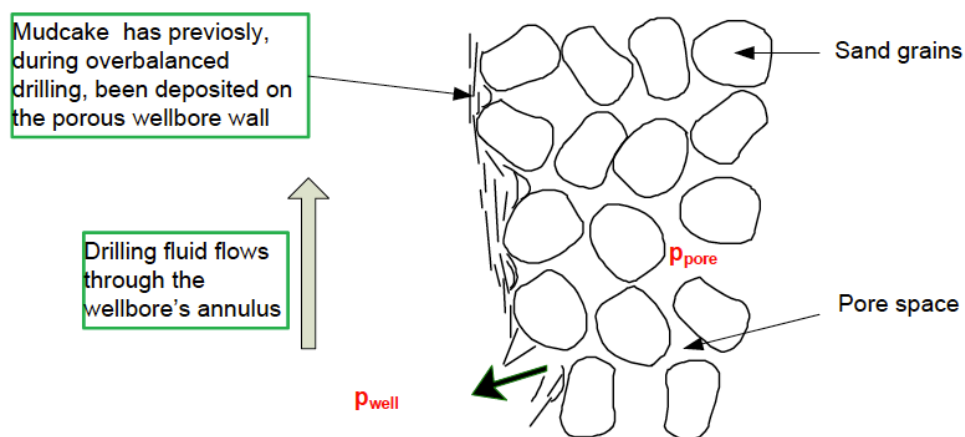


Figure 15: Formation fluids enter the wellbore due to the pore pressure being higher than the wellbore pressure (Skalle, 2012).

A kick can also occur as a consequence of a lower than expected rate of mud return, which typically happens if a significant mud volume leaks into permeable formations at a lower pressure than the wellbore pressure, called thief zones. This can cause the mud level in the annulus to lower which results in a lowered BHP that might allow influx of formation fluids from another zone to enter the well.

3.2.2.1 Handling Kicks

When a kick occurs during OBD, some action must be taken to regain control (restoring overpressure) of the well. Several different methods exist for regaining overpressure, called killing the well. However, the common strategy applied when a kick is detected is to use the blowout preventer (BOP) and accessory equipment to close the well at the BOP, thus preventing fluids from flowing to the surface. After the well is shut in, mud, with mud weight higher than the formation pressure, is pumped down into the well to circulate out the kick (remove the formation fluids that have entered the wellbore) and restore overbalance. The BOP is opened after overbalance is restored and drilling can resume (Skalle, 2012).

3.2.2.2 Gas Kicks

Incompressible fluids such as salt water and oil are not as difficult to handle during a kick situation compared to gas. This is because gas is compressible and will therefore expand when the pressure decreases. For simplicity, the ideal gas law can be used to illustrate the relation between pressure and volume for a gas, although in reality the gas is not ideal in the wellbore (Skalle, 2012):

$$PV = nRT \quad (3.2)$$

Equation 3.2: The ideal gas law.

Where:

- P is pressure [Pa]
- V is volume [m³]
- n is the number of moles of gas [mol]
- R is the gas constant [J/K·mol]
- T is the temperature [K]

According to the ideal gas law, the gas volume increases by 100% each time the pressure is reduced by 50%. As the gas rises in the wellbore annulus it expands, thus progressively occupying a larger volume and displacing larger amounts of mud as the pressure decreases towards the surface. The BHP decreases as the displaced amount of mud from the annulus increases. This situation can quickly lead to an uncontrolled positive feedback loop where the reduced BHP causes an increase in the influx volume, which again lowers the BHP resulting in increased influx. The gas volume in the mud can also cause a reduction in the mud rheology (plastic viscosity, yield point, density, gel strength etc.), particularly in oil-based muds, which has the potential to cause barite to fall out of the mud thus reducing the mud weight even further. The potentially uncontrolled positive feedback loop between the decreased BHP and increased influx for gas makes it more difficult to handle than salt water or oil influx, and the well control situation can get out of control much more quickly if the correct actions are not taken.

During drilling in deep water where the well pressure is high, the difference in pressure between the bottom of the well and the surface is very large, which means that the volume of a gas bubble will increase significantly before reaching the surface. If the well is not shut in, this rapid gas expansion can have severe consequences, potentially leading to a blowout. If the well is closed (shut-in) when the gas kick is detected, in accordance with Equation 3.2, it will not be able to expand because the volume is constant in the well (fluids other than gas are considered incompressible). The pressure in a well when a gas kick is encountered and after it is shut-in is shown in Figure 16. If neither the formation nor the equipment fails as the gas bubble rises to the surface, it will have brought the formation pressure up to the surface, as shown in Figure 17 (Skalle, 2012).

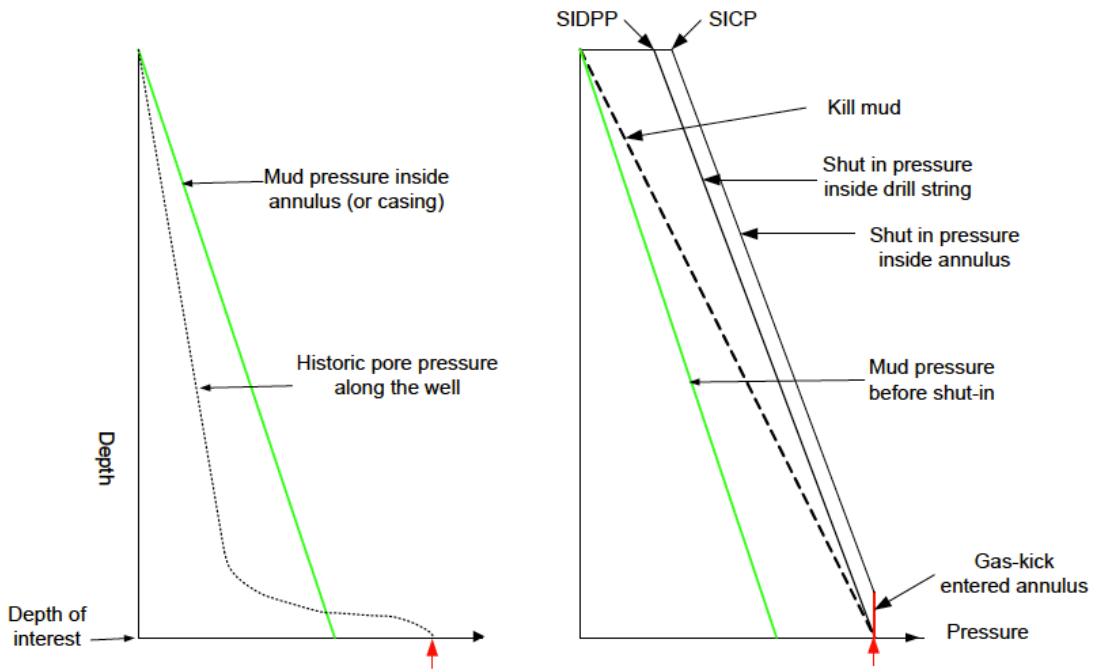


Figure 16: The red arrow shows the depth and pressure of the gas influx. The figure to the left shows the surface and BHP in the well before shut-in. The figure to the right shows the surface- and BHP in the well after it has been shut-in and allowed to stabilize (Skalle, 2012).

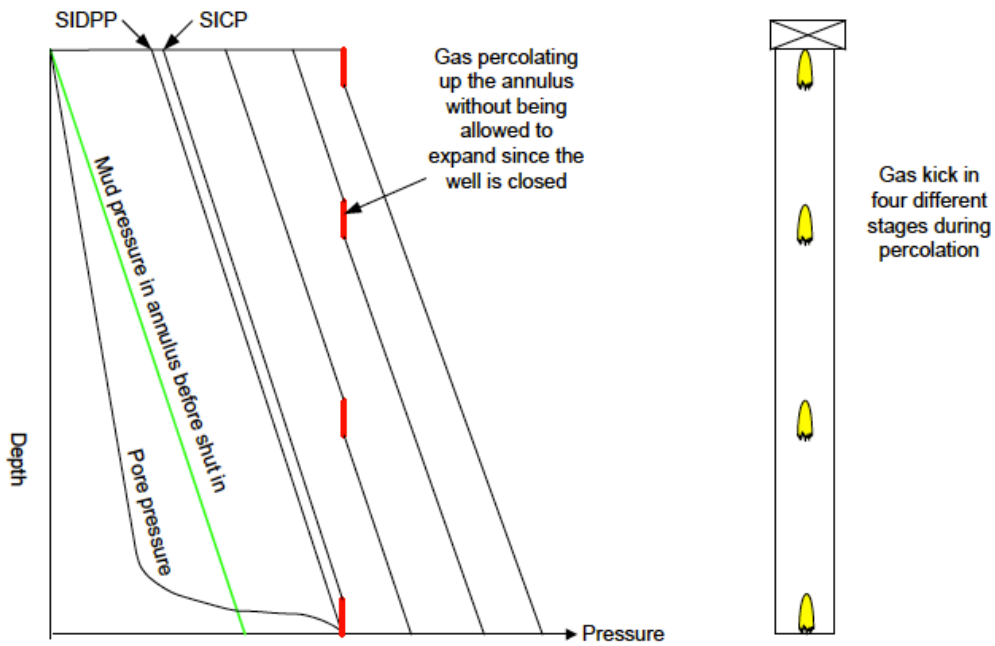


Figure 17: During a gas kick when the well is shut in, the pore pressure from the formation where the influx originated is brought along with the gas bubble to the surface, given that the formation and equipment can withstand the pressure (Skalle, 2012).

3.3 Types of Gas Hydrate Issues Encountered During Drilling

During drilling, three types of GH issues can be encountered (Skalle, 2012):

1. HBS, generally located at shallow depths below the seabed (assuming drilling in marine environments).
2. GH formation (referred to as hydrate formation) in an external unsealed annulus that might obstruct hydraulic disconnection of the marine drilling riser at the BOP, where the source of gas is shallow gas bearing sands at increased depths.
3. GH formation inside the wellbore and/or BOP equipment, which can obstruct access to the wellbore during killing operations and/or obstruct the control of BOP functions. More specifically, some of these problems are (Amodu, 2008):
 - i. Well circulation will be difficult or impossible if the choke-line and kill-line are plugged by GHs.
 - ii. It will become difficult or impossible to monitor the well pressure if a plug forms at or below the BOPs.
 - iii. Movement of the drill string will become difficult if a plug forms around the drill string in the riser, BOP stack or casing.
 - iv. It will become difficult or impossible to achieve a full closure of the BOPs when required if a plug forms in the space between the drill string and the BOPs.
 - v. There might be difficulties in opening the BOPs fully if the ram cavities of the BOPs are plugged.

3.3.1 Hydrate Bearing Sediments

The first type of GH issue, where HBS are encountered, generally at shallow depths below the seabed, is the main focus of this chapter. This section will present the most common and unique challenge when drilling through HBS, while the drilling-related challenges are further discussed in section 3.4. In general, drilling through HBS is characterized by observing extraordinarily large amounts of methane gas during drilling, as well as increased acoustic velocities and electrical resistivity measured downhole (Thomas, 2001).

The most apparent and unique challenge when drilling through HBS is that the cuttings and formation will contain GHs. Cuttings will be transported up the annulus to the surface during the drilling process while suspended in the drilling mud. As they rise in the annulus, the decreasing pressure, along with possible heat transfer from the mud, will remove the GHs from the P&T conditions of the GHSZ. Consequentially, the GHs will start to dissociate into gas and water. This leads to a large volume expansion as 1 m³ of methane GH occupy 164 Nm³ of free methane gas and 0.8 m³ of water.

If the quantity of the gas being released is low, the effect will be the same as a “gas cut” occurring from a small gas influx of formation fluid, but if the quantity is large it will cause a rapid gas expansion in the annulus that ejects fluid from the well. This small gas quantity will only serve to reduce the mud weight, while the ejection of drilling mud will decrease the BHP by reducing the height of the wellbore fluid column. The decreased BHP in the well will result in reduced probability of GH stability and have the potential to increase the rate of dissociation both from cuttings and the formation, leading to additional fluid ejection. If the hydrostatic fluid column is sufficiently decreased due to this violent ejection of fluid from the annulus, the BHP will drop below the formation pressure and a kick will occur.

Situations can also occur where GHs behind the casing start to dissociate due to heat transfer from the circulating mud, which for example occurs when drilling deeper and warmer formations that leads to warm mud heating the shallower sections. This can lead to a pressure build up behind the casing, in the worst-case causing the casing and cement to crack and burst, causing a well control situation that might even make it necessary to abandon the well.

3.3.2 Hydrate Formation in an External Unsealed Annulus

The second type of GH issue, where an external unsealed annulus is plugged, can be solved completely or at least significantly reduced by diverting any gas seepage away from the BOP area. According to Skalle (2012) this can be achieved by inserting a GH seal in the form of a so-called mud mat, and this type of GH issue is therefore not described further.

3.3.3 Hydrate Formation Inside the Wellbore and/or BOP Equipment

The third type of GH issue, where GHs form inside the wellbore and/or BOP equipment, can present a serious well control risk. During conventional drilling and or circulation operations, warm mud is circulated through the drill string and annulus. The risk associated with GH formation in this situation is low because the temperature in the well is generally too high for stable GHs to form. In the GH phase diagram this P&T condition would be viewed as a point above the GH-gas phase boundary.

The risk is significantly increased if a gas kick is encountered and the well is subsequently shut in. The gas quickly rises in the annulus and may enter the wellbore, drill pipe, BOP stack, and choke- and kill lines before the BOP closes. Due to the consequential lack of circulation of warm mud and the low temperature close to the seabed where the BOP is located, the warm high-pressure gas influx can cool down to seabed temperatures during an extended shut-in (Ebeltoft et al., 2001). Given a sufficient hydrostatic pressure at the seabed, GHs could form in the drill pipe, BOP stack and in the choke- and kill lines. Flow blockage, obstruction to drill string movement, loss of circulation, loss of BOP function and even well abandonment could be the result of this potentially hazardous situation. Even if the well control situation is resolved, removing the GH plugs can be a time-consuming and costly operation that will have to be performed before circulation and drilling operations can resume.

GH formation can be limited by adding kinetic inhibitors and crystal modifiers to the drilling mud, which inhibits formation and growth of GH crystals (Helgeland et al., 2012). Because the rate of dissociation decreases with decreasing temperature (Levik, 2000), reducing the mud temperature that circulates in the well will reduce the GH formation issues encountered during extended shut-ins. This is because there will be less free gas to form GHs in the well and also because the formation of GHs will occur at a slower rate. Several technologies for controlling the temperature of the mud are described in section 3.7.

3.4 Challenges Related to Drilling Through Hydrate Bearing Sediments

The probability of encountering HBS during drilling have increased significantly over the last 20 years due to the increased pressures and lower seabed temperatures encountered as offshore drilling have moved into deeper and deeper waters. And while GH zones used to be regarded as a drilling hazard that had to be drilled through as safely and effectively as possible to reach the underlying target oil or gas reservoir, it is now increasingly being viewed as a potential energy resource for the 21st century. One of the keys to unlocking the potential of this resource is to overcome the unique challenges related to drilling production wells in hydrate formations. The challenges are the same for both onshore and offshore drilling, though they are increasingly difficult for offshore drilling because of the water depth, temperature, potentially strong currents (affecting the riser), and seabed subsidence. Most of the challenges are related to limiting GH dissociation due to changes in P&T conditions during drilling. Todd et al. (2006) states that these challenges include:

1. *Narrow margins between pore pressure and fracture pressure in ocean surface sediments (a problem for all offshore drilling operations, increasing in severity with increasing water depth) and within the hydrate reservoir*
2. *Surface hole instability*
3. *Wellbore stability*
4. *Subsidence caused by hydrate production*
5. *A requirement to manage temperatures and pressures within the wellbore during drilling to limit hydrate dissociation in the reservoir and within annulus mud and cuttings returns to the rig*
6. *A requirement to avoid pressure fluctuations within the open hole common to conventional drilling methods (e.g. swabbing, surging, and ballooning)*
7. *A requirement for at-balance installation of liners, screens, and other completion methods*
8. *Drilling extensive wellbores within hydrate zones magnifies the necessity for total well control over a longer time interval than previously required*
9. *Facilitating a rapid response to combat pressure and/or temperature anomalies occurring at any location within a wellbore during the drilling and completion process*

The challenges faced when drilling through HBSs leads to the conclusion that the drilling methods and techniques that are best suited for drilling through HBS are able to:

- i. Closely monitor and control the wellbore pressure and temperature
- ii. Reduce the stress to the hydrate formation, for example by using appropriate wellbore construction and fluid programs

The next section will evaluate three drilling technique candidates according to how well they solve the previously mentioned challenges, and will recommend one as the best suited for drilling through HBS. One of the most important requirements will be for the drilling process to control temperature and pressure throughout the entire wellbore to limit or avoid GH dissociation of the formation and in wellbore.

Controlling the dissociation of GHs is especially important for wellbore stability during drilling. GH dissociation in the formation causes borehole instability because the GHs act as the “cement” in many unconsolidated sediments. Dissociation of these causes a weakening of the sediments that can lead to decreasing formation strength, hole enlargement (washouts and cavings), sand production, subsidence and even borehole collapse.

3.5 Evaluation of Different Drilling Techniques

The three types of drilling techniques that will be evaluated to be used for drilling through HBS are: conventional overbalanced drilling (OBD), underbalanced drilling (UBD) and managed pressure drilling (MPD).

3.5.1 Overbalanced Drilling

The previously mentioned challenges facing drilling operations in HBS does not necessarily mean that conventional OBD cannot be used to drill through HBS, which has been done successfully in the past. Instead it suggests that in cases where the drilling-challenges are difficult to overcome with conventional methods, which are mainly related to GH dissociation in the formation and cuttings during drilling, more modern tools and technologies can be used (Hannegan et al., 2004).

OBD is unable to rapidly react to pressure and temperature anomalies at any location within the wellbore during drilling because the pressure in the well is almost entirely controlled by the hydrostatic mud column in the well, which means that adjusting the pressure in the well requires the time consuming process of circulating mud of a different density into the wellbore. Because the pressure on top of the mud column is atmospheric, a backpressure cannot be applied to counteract the effects of the equivalent circulating density (ECD), which is the difference in wellbore pressure when the pumps are on or off, and pressure fluctuations such as swabbing, surging and ballooning. This means that the HBS will be affected by considerable pressure fluctuations during drilling. Dealing with GH dissociation from the formation and cuttings will also be difficult with the OBD drilling technique as it lacks the equipment and processes to manage a product that expands well over a hundred times when dissociating from GH form to free gas. In addition, because OBD has an open circulation system where mud returns to the surface and flows out of the well through piping open to atmospheric pressure, the well will have to be frequently shut in during drilling to circulate out gas in the well, which will result in considerable non-productive time (NPT).

Another possible challenge when drilling through HBS with OBD is that the pressure in the wellbore is likely to be insufficient to prevent dissociation of GHs within the cased and open hole. In addition, conventional methods might not be sufficient to resolve encountered well control situations. The conventional method of regaining

control of a well by increasing the mud weight might not work if the well control situation originated because the GHs has been made unstable due to a too high temperature, not because the pressure is too low. Increasing the pressure in this case will not bring the GHs inside the P&T conditions where they are stable, and will therefore not slow or stop the dissociation. Increasing the mud weight might instead fracture the formation, causing fluid loss that decreases the hydrostatic pressure in the well, worsening the situation.

From a production point of view, drilling through the hydrate reservoir is likely to cause invasive formation damage, as the the hydrostatic pressure at the bottom of the well in the annulus during OBD is higher than the formation pressure, meaning that mud and cuttings will flow into and damage the near wellbore area. This will have the possibility to significantly reduce the productivity of the hydrate reservoir, or even rendering it unable to produce at all (Todd et al., 2006).

Due to the reasons mentioned in this section it is the conclusion that while drilling production wells through HBS is possible with OBD, it is far from the optimal solution, and presents drilling problems that are difficult to overcome.

3.5.2 Underbalanced Drilling

Eck-Olsen et al. (2011) states that the three main differences between conventional OBM and UBM are:

1. *The arrangement of the drilling fluid circulation system*
2. *The pressure conditions in the wellbore and the manner by which wellbore pressure is controlled during the operation*
3. *The measures used to contain formation fluids, control their inflow into the wellbore, and evacuate them from the wellbore and from the surface working area*

Underbalanced drilling is characterised by deliberately keeping the pressure at the bottom of the fluid column in the wellbore annulus below the formation pressure, thus formation fluids flow into the wellbore, referred to as inflow, that are removed from the wellbore at the surface. A backpressure (Figure 13) is applied at the surface to regulate the rate of inflow and the rate of which formation fluids at the top of the well are withdrawn. The formation fluids are separated at the surface (Figure 18). Decreasing the backpressure at the surface will decrease the pressure at the bottom of the well, and increase the inflow and fluid withdraw rate, while the opposite will be the result if the backpressure is increased.

Drilling into hydrate reservoirs with UBD, meaning that the formation fluids flow into the wellbore due to the lower pressure in the wellbore compared to the formation, has the risk of creating an out-of-control dissociation “chain reaction” and causing significant wellbore stability problems. The low wellbore pressure will cause GHs in the formation and cuttings to dissociate more rapidly than during OBD, and the gas volume entering the annulus and rising to the surface will significantly increase in volume, which will displace the mud and result in a reduction of the annulus pressure at the bottom of the well, leading to an increase in the dissociation rate. The limited amount of backpressure in typical UBD operations means that the pressure is not controlled throughout the wellbore until the inflow enters the production equipment, at least not to the point where the GHs are stable, which means that the GHs will expand fairly freely in the well. One major advantage when drilling through the hydrate reservoir with UBD is that there will be no invasive formation damage because there is

no overpressure in the well, meaning that the drilling process will not cause a reduction in the reservoir's production potential.

Although this technique is much better at handling gas in the well and at the surface compared to OBD, the lack of control over the GH dissociation process in the formation and cuttings during UBD and the associated well control risks, in addition to the wellbore stability risks, leads to the conclusion that UBD is not the optimal drilling technique for drilling production wells in HBSs.

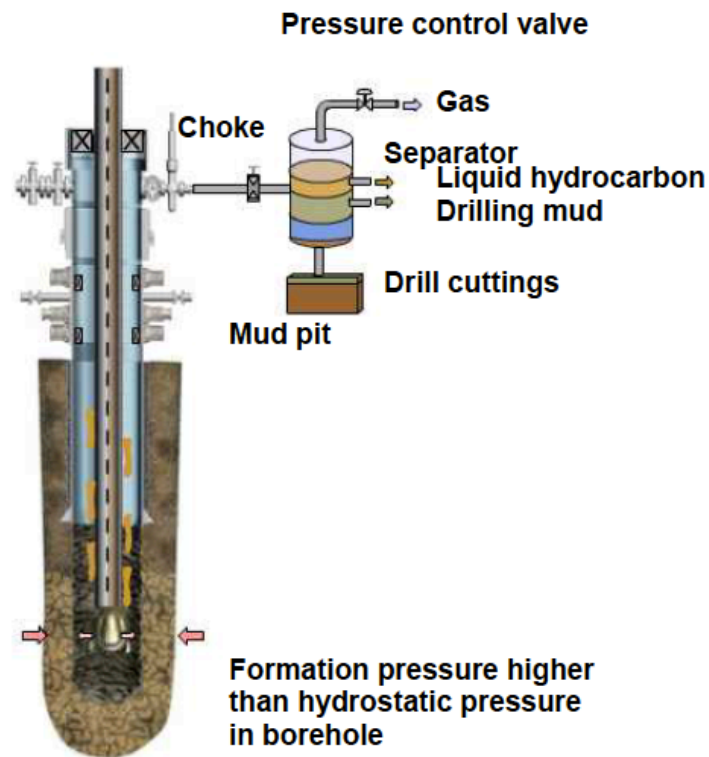


Figure 18: Illustration of the drilling and production equipment used during UBD. UBD invites inflow from the formation and withdraws and separates formation fluids from the well at the surface (Eck-Olsen et al., 2011).

3.5.3 Managed Pressure Drilling

The international Association of Drilling Contractors Subcommittee on Underbalanced and Balanced Pressure Drilling has defined MPD as:

An adaptive drilling process used to precisely control the annular pressure profile throughout the entire wellbore. The objectives are to ascertain the downhole pressure environment limits and to manage the annular hydraulic pressure profile accordingly.

MPD is an “adaptive drilling process” where the drilling plan, operation and pressure profile in the well changes during drilling according to the conditions of the wellbore to *precisely control the annular pressure profile throughout the entire wellbore*. The objective is to monitor the limits of the downhole pressure environment and adjust the annular pressure profile appropriately, which is well suited from drilling through HBS, and especially well suited for drilling through the hydrate reservoir. Contrary to UBD, which deliberately allows the influx of formation fluids into the wellbore, MPD will generally avoid flow into the wellbore, similarly to OBD. Any unexpected inflow that occurs during the drilling process will be safely contained using a suitable process (Todd et al., 2006). The very limited overpressure during MPD means that invasive formation damage in the reservoir is likely to be significantly reduced compared to OBD, and is not expected to significantly affect the production potential of the reservoir.

The common characteristic of the many different MPD tools and techniques that exist is that they were developed to limit well kicks, lost circulation and differential sticking, so that fewer casing strings would be needed to reach the total depth of the well. Although drilling with MPD has many advantages, those that are most relevant when drilling through hydrate formations is that it reduces problems when drilling through formations with a narrow margin between the formation pressure and the fracture pressure, which generally causes frequent losses of drilling mud and gains of formation fluids, and that it precisely controls the pressure of the entire wellbore during drilling, and is able to react quickly to changes in the wellbore pressure. The evaluation of the drilling techniques continues in the next section.

3.5.4 Recommended Drilling Technique

Dissociation of GHs during drilling can occur in the formation, wellbore, or at the surface. Figure 19 is a schematic presentation of the P&T conditions in the wellbore during drilling with the three drilling techniques: OBD, UBD and MPD (green, blue and red dashed lines respectively), of the indigenous formation during drilling (black dashed line), along with representation of GH phase boundary curves representing three different gas compositions (black lines) (Todd et al., 2006). Points in the diagram above the GH phase boundary curves represent conditions where GHs are stable, while points below represent conditions where the GHs are unstable. Although this is a schematic example, it shows that if the OBD or UBD techniques are applied for drilling in a HBS, cuttings will at some point start to dissociate as they are transported to the surface. On the other hand, during drilling with MPD it is suggested that the wellbore conditions can be managed to prevent dissociation of the GHs in the wellbore entirely.

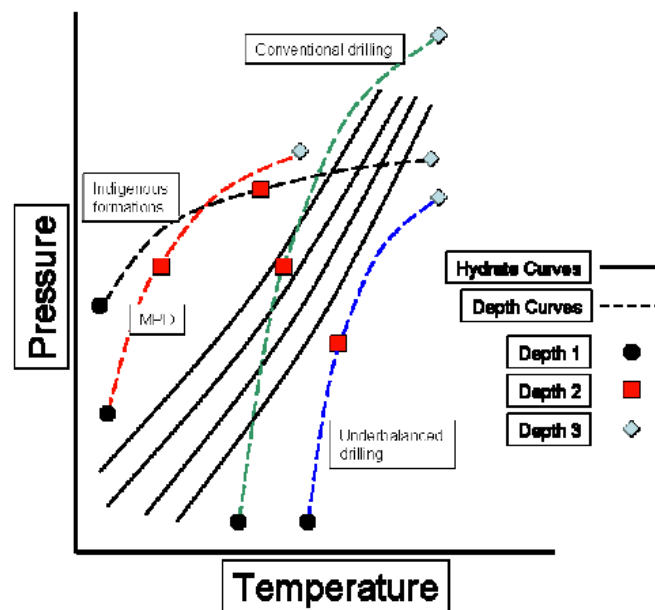


Figure 19: Schematic presentation of the OBD-, UBD-, MPD- techniques and their P&T relationship in the wellbore during drilling along with the representation of GH phase boundary curves (Todd et al., 2006).

Based on the precise control of the annular pressure profile throughout the wellbore during MPD, the techniques ability to react quickly to changes in the wellbore pressure and likelihood of preventing GH dissociation in the formation and cuttings, the conclusion of the evaluation is that MPD is the drilling technique that is best suited for drilling production wells in HBS.

3.5.4.1 Required Managed Pressure Drilling Equipment for Drilling Through Hydrate Bearing Sediments

The following equipment is necessary to safely and efficiently drill through HBS with MPD (Hannegan, 2005):

- *Rotating control device*
- *Choke manifold*
- *Drill string non-return valves*
- *Real-time temperature and pressure monitoring*
- *Modular multi-phase surface separation system with optimal retention time*

The combination of the rotating control device and the choke manifold is necessary technology to apply backpressure during drilling, which is highly important to limit GH dissociation in the annulus. The drill string non-return valves are required to isolate and maintain a pressurized wellbore during connections with a sufficient backpressure to prevent GH dissociation in the wellbore and annulus. Without the non-return valves in the drill string, the pressure would drop during every make-up and break-out of drill pipe connection and cause GH dissociation. Real-time temperature and pressure monitoring will be necessary to continuously monitor the temperature conditions in the wellbore. Changes in the wellbore environment, for instance rapid increases in the downhole temperature can then quickly be met and resolved by, for example, increasing the circulation, increasing the pressure, or lowering the mud temperature through regulating the surface mud cooling system. A specially designed modular multi-phase surface separation system will be required to facilitate the separation of the cold returning mud and the safe and controlled dissociation of GHs in the cuttings. The separation system must be designed with a retention time that allows for the near-complete dissociation of the GHs through a gradual pressure decrease and temperature increase. The temperature increase is likely to require an external heat source (Hannegan, 2005).

3.6 Possible Solutions for Hydrate-Related Drilling Problems

Now that MPD has been evaluated to be the most suited drilling technique for drilling production wells through HBS, the view is shifted towards which other measures that can be taken to reduce the risks of drilling through HBSs. According to Khabibullin et al. (2011), these include:

- *Cooling the drilling fluid*
- *Increasing the mud weight to stabilize the hydrates, but avoiding fracturing the HBS*
- *Adding chemical inhibitors and kinetic additives to the drilling fluid to prevent hydrate formation and to reduce hydrate destabilization in the formation*
- *Accelerating drilling by running casing immediately after hydrates are encountered and using a cement of high strength and low heat of hydration*
- *Managing the wellbore temperature by controlling the circulation rate*

Several different types of methods and technologies that are possible solutions for GH-related drilling problems are described in section 3.8. One of the most important factors to drill successfully through HBS with the smallest amount of GH dissociation is to control and maintain a low temperature throughout the wellbore and up to the surface. How this can be achieved is discussed in the next section along with a description of the mechanisms that generate heat in the wellbore during drilling.

3.7 Temperature Control Throughout the Wellbore During Drilling

Monitoring and controlling the temperature in the wellbore during drilling in HBS relative to the stability areas of the GHs will be necessary to either avoid or severely reduce GH dissociation throughout the wellbore, which is very important to reduce hole stability issues and other drilling-related challenges. Keeping a low temperature in the circulating mud can be achieved by either cooling the mud, or minimizing heat transfer (insulation) to the mud from the warmer environment. According to Hannegan (2005), keeping the temperature within the closed circulation system utilized in the MPD technique lower than 11°C will discourage GH dissociation, although others argue that the temperature should be maintained as low as 0°C. The next section will present the effects during drilling that heat the mud, while section 3.7.2 and 3.7.3 will describe how surface mud cooling and insulation can be used to maintain a low mud temperature during drilling.

3.7.1 Wellbore Heating Effects During Drilling

The effect during drilling that heat the mud during circulation is frictional heat which generally originates from the following two main sources during drilling operations: viscous friction and mechanical friction.

3.7.1.1 Heating Effects Due to Viscous Friction

Viscous friction is an energy dissipating effect that occurs a result of fluid viscosity effects. The effect develops whenever a fluid flows, both within the flowing fluid stream and along any surfaces the fluid is in contact with. This occurs for example when the open rock formation, casing or the drill pipe is in contact with the circulating mud. The magnitude of the viscous friction is often much less than the mechanical friction unless for the case of circulation in a vertical wellbore, and can often be neglected without creating significant errors (Nguyen et al., 2010).

The pressure generated by the high-pressure mud pumps are used to overcome the pressure loss in different parts of the drilling mud system, such as the topside pipes, mud motors, drill pipe, drill bit and annulus. The heating effects due to viscous forces in the wellbore depends on the total pressure loss in the wellbore, which is the sum of the pressure losses through the drill pipe, drill bit and annulus due to viscous friction. This pressure loss will cause the temperature to increase in the well. According to Maury and

Guenot (1995), the heat generation is a result of pressure losses and is given by the equation:

$$\Delta T = \frac{\Delta P}{\rho C_p} \quad (3.3)$$

Equation 3.3: Heat generation as a result of pressure losses (Maury and Guenot, 1995).

However, for the temperature to increase in the wellbore as a result of viscous friction in the circulating fluid (and consequentially a pressure loss), a negative sign in front of ΔP has been added. The temperature increase in the wellbore due to viscous friction in a flowing fluid when the pressure decreases is given by:

$$\Delta T = \frac{-\Delta P}{\rho C_p} \quad (3.4)$$

Equation 3.4: Change in temperature due to change in pressure.

Where:

- ΔT is the change in temperature [$^{\circ}\text{C}$]
- ΔP is the pressure increase [Pa]
- ρ is the density of the drilling mud [kg/m^3]
- C_p is the heat capacity [$\text{J}/\text{kg}^{\circ}\text{C}$]

Equation 3.3 shows that as the pressure losses in the drill bit, annulus and drill pipe due to viscous friction will result in a temperature increase that will transfer heat to the mud. It is important to note that the heat capacity of the mud has a large influence on the temperature change. Comparing oil-based mud ($C_p = \sim 2,000 \text{ J}/\text{kg}^{\circ}\text{C}$) with water-based mud ($C_p = \sim 4,000 \text{ J}/\text{kg}^{\circ}\text{C}$), it is clear that oil-based mud will be heated significantly more than water-based mud given an equal pressure drop (Maury and Guenot, 1995).

3.7.1.2 Heating Effects Due to Mechanical Friction

Mechanical friction occurs from the drill bit, or from drag forces between the drill pipe and the open formation, or between the drill pipe and casing, and generates heat in the wellbore that is conducted away by the circulating fluid, resulting in a heating of the mud. Nguyen et al. (2010) investigated a 3D drag and torque model and estimated the heat generated by the mechanical drag forces (Equation 3.5; Equation 3.6), and

recommended to use the general formula in Equation 3.7 to estimate the heat generated at the drill bit.

$$Q_{drag} = \int_{s1}^{s2} \mu_f \cdot w_c \cdot r_p \cdot 2\pi N ds \quad (3.5)$$

Equation 3.5: The heat generated from mechanical drag when drilling in rotating mode (rotary drilling) (Nguyen et al., 2010).

Where:

- Q_{drag} is the heat generated [W]
- μ_f is the coefficient of friction [dimensionless]
- w_c is the unit contact force [N]
- r_p is the radius of the drill pipe [m]
- N is the rotary speed, the number of drill pipe rotations per second [s^{-1}]

$$Q_{drag} = \int_{s1}^{s2} \mu_f \cdot w_c \cdot ROP ds \quad (3.6)$$

Equation 3.6: The heat generated from mechanical drag when drilling in sliding mode (drilling with downhole motor) (Nguyen et al., 2010).

Where:

- ROP is the rate of penetration [m/s]

$$Q_{bit} = (1 - \beta)(WOB \cdot ROP + 2\pi \cdot N \cdot M_{bit}) \quad (3.7)$$

Equation 3.7: The general equation to estimate the heat generated by the drill bit (Nguyen et al., 2010).

Where:

- Q_{bit} is the heat generated [W]
- β is the bit efficiency, which is the fraction of work done by the drill bit used to break the rock. $(1 - \beta)$ is the heat generated [dimensionless]
- WOB is the weight on bit [N]
- M_{bit} is the drill bit torque [N·m]

3.7.2 Surface Mud Cooling

The temperature of the mud should be kept at a level that does not disturb the stability of the GH, which according to Hannegan (2005) means keeping the temperature within the closed circulation system below 11°C throughout the wellbore. To achieve this objective, surface mud cooling will have to play an important part. Surface mud cooling can be done in many different ways, for example the addition of blocks of ice in the mud or cooling the mud through a heat exchanger. In addition to stabilizing the GHs and reducing or eliminating GH dissociation, which is the most important advantage, mud cooling has the following additional advantages (Maury and Guenot, 1995):

1. *Increased borehole stability*
2. *Reduce the mud temperature while circulating and drilling and therefore help maintain the rheological properties of the mud with less additives*
3. *Reduce bit temperature and wear on downhole tools that may be affected by high temperatures*
4. *Reduce the high mud return temperature, especially important for oil-based muds, which can thus be maintained below their flashpoint*
5. *Maintain the mud temperature below the design failure limits of BOP elastomers*
6. *Reduce the bottomhole circulating temperature allowing the use of measurement while drilling and logging while drilling tools to greater depths*

Maury and Guenot conducted a full-scale study in 1995 of different types of heat exchangers and cooling fluids for the application of mud cooling based on cost, size, efficiency, maintenance requirement, risk of mud clogging and ability to handle dissolved gas. The conclusion of the study was that the plate heat exchanger was the best option due to: lower cost and size, high cooling efficiency, high fluid velocity and expected low probability of clogging, easy to perform maintenance and no problems with degassing. An onshore full-scale pilot test was performed for 160 hours while drilling from 3,750 meters to 4,350 meters with very good results. The surface mud cooling system lowered the temperature of mud pumped down the well from 50°C to 30°C, decreased the bottomhole temperature by 10-12°C, and increased the rate of penetration by 20%. One interesting observation was that the bottomhole temperature was significantly decreased, with a corresponding increase in the surface temperature,

when pipe rotation was completely stopped with the circulation still on. This was found to be a result of a variation of the heat transfer coefficient at the outer wall of the drill string during pipe rotation. This means that stopping pipe rotation with the circulation still on, will significantly increase the bottomhole cooling, although the upper parts of the wellbore will see an temperature increase (Maury and Guenot, 1995).

A much more recent experience with surface mud cooling was done by Vrielink et al. (2008). In this “two-step” highly automated system, glycol was first precooled in an ammonia refrigeration system using a plate and frame heat exchanger before being circulated in a spiral heat exchanger to cool the mud (Figure 20). This high capacity mud cooling system was connected to the suction pit where it circulated and cooled the mud, and it proved to be a highly reliable method. The relatively large gap in the spiral heat exchanger minimized plugging problems caused by drilling mud while at the same time achieving a large surface area and long contact time. Impressively, the surface mud cooler did not have any difficulties in maintaining the inlet mud temperature at -3°C for the surface hole and between -1°C and 0°C for the intermediate and main hole section while drilling two wells in the Arctic (Vrielink et al., 2008). From this experience it is clear that surface mud cooling down to mud inlet temperatures close to 0°C is possible with current technology.

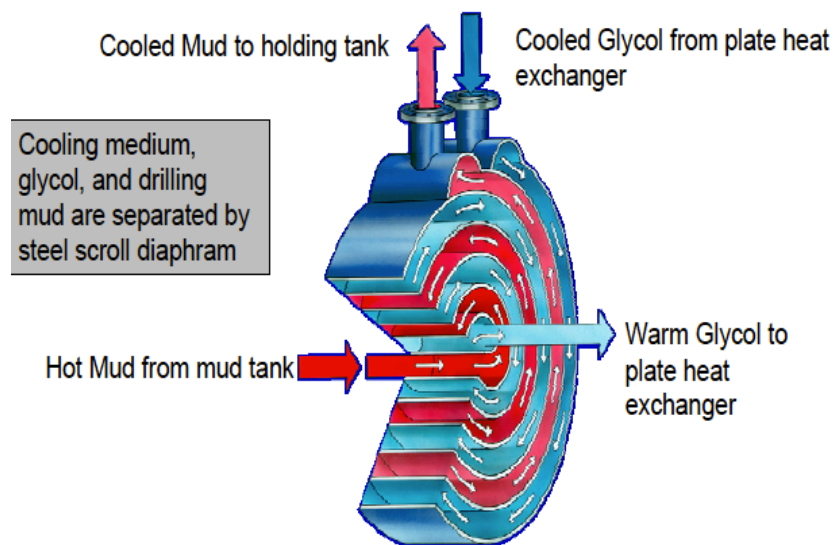


Figure 20: Spiral heat exchanger where cooled glycol is used to cool down the temperature of the mud (Vrielink et al., 2008).

3.7.3 Insulation – Equipment and Technology for Minimizing Heat Transfer

One way of controlling the temperature of the mud without artificial cooling is through minimizing the heat transfer to the mud in the wellbore. This can be done by one of the following equipment and technologies:

- Marine riser (slim, insulated, dual flow, with surface BOP and/or pressurized, and booster line)
- Insulated dual flow drill pipe
- Casing insulation

3.7.3.1 Marine Riser (Slim, Insulated, Dual Flow, with Surface BOP and/or Pressurized, and Booster Line)

The standard method in the oil and gas industry is to use risers to transport the fluids from the well to the rig in offshore fields. To achieve this in an controlled manner while drilling in HBS will be a difficult challenge since the riser is the environment where the pressure will be fairly low and the temperature will be fairly high, meaning that the GHs will be at its most unstable. As most of the riser is fully submerged in seawater it will be at approximately the same temperature as the seawater. This means that heat will be transferred from the seawater through the riser and into the mud with suspended GHs, potentially lead to dissociation, assuming that the seawater is warmer than the fluid in the annulus. This heat transfer could be significant, especially in temperate waters.

This heat transfer could be limited by using an insulated riser with a lower heat transfer coefficient, thus limiting the temperature increase, and therefor the dissociation and expansion of the GHs in the mud, but this is excessively expensive. Instead, the insulation could be achieved by a dual flow configuration with a cold fluid circulating in the riser annulus. A pressurized riser with a surface BOP would permit a much higher pressure in the riser, meaning that the GHs would be stable at higher temperatures. A final option could be to use a slim riser, a riser with a smaller outside diameter than what is conventional, which will result in higher fluid velocities in the riser and therefore reduce the heat transfer to, and heating of, the mud (Todd et al., 2006). The booster lines on the riser are used to inject mud at the base of the riser, which is necessary to maintain the return fluid velocity in the riser at the same level as in the annulus of the wellbore, since the diameter of the riser is larger than that of the annulus

in the wellbore. If the mud injected down the booster lines is cooled, this will increase the stability of the GHs suspended in the mud. According to Hannegan et al. (2004), maintaining a bottomhole temperature at 11°C is likely to prevent any GH dissociation in the wellbore and release of free gas in the riser.

3.7.3.2 Insulated Dual Flow Drill pipe

In situations where a riser is unpractical to use, one method to transport the returns to the surface from the wellhead could be through an insulated dual flow drill pipe. To reduce the heat transfer between the seawater and formation, each joint would be equipped with an insulated “covering” between the pin and box that had the same outside diameter as the pin and box. This drill pipe would have to be able to withstand the high pressures associated with GHs dissociating inside the pipe (Todd et al., 2006). According to Hannegan et al. (2004) this type of drill string is worth considering based on the heat transfer between the mud in the drill pipe and the mud return in the annulus during drilling with conventional drill pipe. The returns would be channelled into one-half of the dual-flow drill pipe near the bottom hole assembly (BHA), while the mud and returns would be separated at the rig floor by a unique swivel mechanism.

3.7.3.3 Casing Insulation

Using an insulated outer casing would reduce the heat transfer between the formation and the well, thus reducing the temperature increase of the formation in sections where the temperature of the annulus is higher than that of the formation. This is especially important in limiting the heating of shallower hydrate formations when drilling deeper warmer zones, and during production, especially if the production method involves thermal injection, such as steam injection (Kallhovd et al., 2012).

3.8 Equipment, Methods and Technologies for Drilling-Related Gas Hydrate Problems

In addition to the mentioned equipment and technologies for controlling the temperature in the wellbore, the following drilling-related equipment, methods or technologies could be combined with MPD (the recommended drilling technique) to reduce problems when drilling through HBS:

- Casing while drilling
- Low exothermic cement
- Thermodynamic inhibitors and kinetic inhibitors/anti-agglomerates
- Circulation Rate

3.8.1 Casing While Drilling

Casing while drilling (CwD) involves using the well casing with a drill bit attached at the end of the drill string and rotating it from the surface to penetrate into the earth's crust, in this way the well is both drilled and cased at the same time. The drill string is then cemented in place in the well after reaching the target depth (TD). The drilling fluid is circulated down the inside of the casing and returns up the small annulus between the outer diameter (OD) of the casing and the formation. The large OD of the casing generally leads to considerably good hole cleaning due to the high annular fluid velocities in the small annulus, particularly at critical angles (Karimi et al., 2011). Since the well is cased during drilling there is generally no tripping of the drill string. This serves to reduce many of the common drilling problems generally encountered during drilling, which is the main advantage of CwD, such as: stuck pipe, lost circulation, wellbore instability, drilling induced formation damage, and especially well control issues, and the NPT associated with these problems (Strickler et al., 2004). This is a proactive approach to drilling where problems are prevented before they occur instead of being dealt with afterwards.

Two types of systems exist, non-retrievable CwD system and the retrievable CwD system. The non-retrievable systems have a fixed drill bit that is either a conventional drill bit that is left in the well after reaching TD, or a bit that can be drilled through (drilled out) when drilling the next hole section. Replacing the bit and BHA

with this system would require the whole casing string to be tripped out of the hole. This is in contrast with the retrievable system where the bit and BHA can be changed without tripping the casing string. When drilling directional wells the retrievable system is the only practical choice, mainly because the expensive directional drilling and guidance tools will have to be recovered after reaching TD and it must be possible to replace equipment that fails during drilling (Strickler et al., 2004).

Drilling with casing can be combined with different drilling methods such as; OBD, UBD or MPD, and may be well suited for drilling through HBS. The high annular velocity would carry the GHs in the cuttings to the surface more quickly, thus reducing the possibility of, or limiting the extent of, GH dissociation in the annulus by reducing the time the GHs are exposed to P&T conditions in which they are unstable. The risk associated with seafloor collapse and problems related to general wellbore stability throughout the well due to temperature, pressure and GH dissociation in the formation would also be significantly reduced, as the time period the formation is exposed to the circulating mud until the formation casing is installed and cemented is reduced. It might also be possible to use a less expensive floating rig to drill the well due to the reduced casing weight (Hannegan et al., 2004).

3.8.2 Low Exothermic Cement

The process where cement sets usually have the property of exothermicity, meaning that heat is released during an exothermic reaction, because heat is released from the hydration reactions of cement components. This heat release does not pose a problem in most areas; however, it becomes a significant problem in Arctic environments where permafrost and/or in environments where GHs are present. The heat that is released during the cement setting process can cause permafrost to thaw and GHs to become unstable and dissociate. Because the ice is the consolidation material in permafrost formations, the formation will transform from firm and stable to soft and unstable when the permafrost melts resulting in the formation of liquid water around the borehole. GHs that have been destabilized will begin to dissociate and release frozen or liquid water together with vast volumes of gas, thus increasing the pressure behind the casing. The situation in both these cases will threaten the integrity of the wellbore and the cement, and might damage significant sections of the wellbore (Bishop et al., 2011).

If gas is present during the hydration reaction of the cement it could invade the cement and migrate through the pore structure along weak bonds, formation/cement interface or cement/casing interface, thus creating micro channels and/or an microannulus that the gas can percolate through both while the cement sets and after the cement has set, reducing the integrity and strength of the cement (Kallhovd et al., 2012).

Schlumberger has come up with a solution for this problem by developing a new line of cements designed specifically for low-temperature applications, called the ARCTICSET cements that are available for a variety of conditions. Although purposely designed for permafrost zones, this line of cement is also highly relevant to be used in formations containing GHs to limit or avoid dissociation during the hydration reaction of the cement since these cements have a low heat of hydration and minimal heat release while setting. Other properties include: low free-water separation, low permeability, excellent resilience to temperature cycling and controllable pumping times and strength properties. Sufficient strength of the cement can be achieved in wells with temperatures down to -9°C (Bishop et al., 2011). An additional improvement of the cement used to cement casings in HBS would be to include components in the cement that would prevent destabilization of the GHs (Helgeland et al., 2012).

3.8.3 Thermodynamic Inhibitors and Kinetic Inhibitors/Anti-Agglomerates

In a situation where dissociation of GHs have occurred in the cuttings or in the formations and free gas has formed, it will be necessary to prevent the reformation of GHs at other locations in the well or riser. If at any location the environment has P&T conditions where GHs are stable, the formation of GHs can still be limited or avoided. Adding chemicals that alters the gas composition can lower the GH formation temperature and/or delay the GH formation. In general there are two options, either adding thermodynamic inhibitors, or kinetic inhibitors/anti-agglomerates.

Thermodynamic inhibitors acts on the chemical potential of water in the aqueous phase to reduce the equilibrium temperature of GH formation, meaning that GH formation occurs at a lower temperature after a thermodynamic inhibitor has been added. Common examples include methanol, monoethylene glycol (MEG), diethylene glycol (DEG), commonly referred to as glycol, and triethylene glycol (TEG), and in drilling fluids; salt solutions (brines). Salt solutions, which are widely used in drilling fluids, generally have a lower effectiveness than methanol and glycols and are also

prone to crystallization. Due to the large quantities required, 10-50% by weight of the fluid for methanol and MEG, an efficient inhibitor generation process is vital when using glycols due to economic reasons (Fadnes et al., 1998).

Kinetic inhibitors and crystal modifiers are a new and evolving technology using mainly polymeric and surfactant-based chemicals (Helgeland et al., 2012). They are also known as low-dose-hydrate-inhibitors because of the much smaller quantities (concentrations) than thermodynamic inhibitors (1% by weight of the fluid when used in pipelines) (Fadnes et al., 1998). Kinetic inhibitors, which do not require a water and hydrocarbon mixture to be effective, delay the formation of hydrates by slowing down the kinetics of nucleation, while crystal modifiers, which requires a water and hydrocarbon mixture to be effective, prevents the growth of hydrate crystals by preventing the crystals from agglomeration (sticking together). Choosing the correct chemicals in a high salinity drilling fluid is a major challenge with this technology (Helgeland et al., 2012).

3.8.4 Circulation Rate

A relatively high circulation rate will reduce the heat transfer between the mud and the formation and between the seawater and mud in the riser, thus reducing the temperature of the mud and leading to improved stability of the GHs. This advantage would have to be considered against the increased mud pump requirement and borehole stability problems due to increased annular flow and therefore borehole erosion.

3.9 Recommended Methods and Technology to be Used With Managed Pressure Drilling When Drilling Production Wells Through Hydrate Bearing Sediments

Based on the drilling techniques, equipment, methods and technologies discussed in this chapter, the recommended system for drilling production wells through HBS is to drill with MPD (with the following equipment: a rotating control device, choke manifold, drill string non-return valves, real-time temperature and pressure monitoring, and modular multi-phase surface separation system with optimal retention time). To reduce drilling-related problems and NPT and increase safety and operational flexibility, it is recommended to combine MPD with the following: casing while drilling (where economically and technically possible), surface mud cooling to reduce the wellbore and riser temperature thus increasing the stability of GH in the annulus and formation, thermodynamic inhibitors and kinetic inhibitors/anti-agglomerates to reduce the probability and consequence of GHs reformation in the wellbore or riser, low exothermic cement to increase the quality of the cement and avoid integrity issues when cementing in HBSs, and drill with a relatively high circulation rate to reduce heat transfer in the wellbore and riser, thus increasing the stability of the GH in the well and formation.

The use of a marine riser (slim, insulated, dual flow, with surface BOP, and/or pressurized, and booster line), insulated dual flow drill pipe and casing insulation will have to be considered in each situation based on a variety of criteria, including: water depth and temperature distribution, well depth, formation temperature distribution, total depth and length of the well, and reservoir temperature.

4 Matlab Simulation for Drilling in HBS

One of the findings in chapter 3 was that maintaining a low temperature throughout the wellbore annulus was very important to limit dissociation of GHs in the formation and in cuttings that are transported to the surface. A model and a Matlab program have therefore been developed to further investigate this topic. The goal of the simulated Matlab program is to determine the annulus temperature distribution when drilling into a hydrate-bearing layer (HBL) at a specific depth, and to determine where GH would be exposed to P&T conditions outside the stability curve. Decreasing the mud inlet temperature to the drillpipe at surface in the program (which would be the result of surface mud cooling in an actual situation) will be important in trying to obtain stable P&T conditions for GHs throughout the wellbore annulus. The model that has been developed is for a 17.5” vertical well that has been drilled to 1,200 meters through sandstone rock layers and that has recently encountered a HBL (Figure 22). The Matlab code can be found in Appendix B.

The model that has been developed for the Matlab simulation has been based on work done by Kallhovd et al. (2012) during an Arctic Drilling Project at the Norwegian University of Science and Technology. The Kallhovd et al. (2012) project regarded temperature modeling and wellbore instability in the Arctic, which included the development of a Matlab model to simulate the annulus temperature distribution over time when drilling through a permafrost zone. However, the model presented in this thesis has been modified and altered to enable simulation of the annulus temperature distribution when drilling into a HBL, and has also been improved upon in other respects. These improvements are further discussion in section 4.7.

The next sections will describe the assumptions behind the developed Matlab model (section 4.1), the equations used in the model for heat transfer, heat generation and heating effects (section 4.2), and how the numerical model was constructed (section 4.3). Suggestions for further work is presented in section 4.8.

4.1 Assumptions and Simplifications of the Model

The following assumptions and simplifications are made for the model:

- Vertical well drilled through a formation that consists entirely of sandstone with 25% porosity down to 1,200 meters depth
- The simulation starts exactly as the HBL is encountered at 1,200 meters
- The well is drilled with a uniform 6 5/8 outside diameter drill pipe, neglecting drill collars to simplify the calculations
- Heat generation from drill pipe friction against formation is negligible because the well is vertical (Equation 3.5 and Equation 3.6) is therefore neglected)
- Heat transfer is controlled by conduction and convection, while radiation heat transfer is assumed negligible and therefore neglected
- Impermeable borehole (no fluid exchange between the annulus and the formation), which means that the heat transfer between the annulus and formation is only through conduction, and not convection
- The heat transfer by convection in the fluid volume of one numerical segment is instantaneous (constant temperature throughout the mud in each numerical segment)
- Formation and mud properties are independent of P&T
- Formation temperature distribution is constant and does not change through heat transfer with the annulus
- Wellbore temperature is independent of drill pipe rotation
- Formation temperature distribution is constant
- The inlet temperature of the mud pumped downhole into the drillpipe is constant
- U_{pipe} , which is the heat transfer coefficient for the drill pipe is constant throughout the drill pipe
- The drill pipe and annulus contains only mud, no cuttings, cavings etc., which means that the heat capacity of the fluid in the drill pipe and annulus is the same as the heat capacity of the mud
- The temperature in the annulus and drillpipe is assumed constant for each numerical segment

4.2 Equations for Heat Transfer, Heat Generation and Heating Effects in the Well

The heat transfer in this model is by conduction and convection, while heat transfer through radiation is assumed negligible. Conduction involves heat transfer between objects that are in physical contact, while convection occurs when the motion of fluids transfer heat between an object and its environment. An example of conduction is the heat transfer that occurs between an impermeable rock formation and the annulus, while an example of convection occurs in the circulating drilling mud when particles of a higher temperature transfers heat to a body of lower temperature through diffusion and collision. In this model, it is assumed that convection occurs instantaneously within each numerical segment volume during the simulation (Figure 22), meaning that the temperature will be the same throughout this specific fluid volume in the drill pipe or annulus. The two interfaces in this model where heat transfer occurs by conduction are between the formation and the annulus, and between the annulus and the inside of the drill pipe. Equation 4.1 gives the instantaneous heat transfer while Equation 4.3 gives the cumulative heat transfer between the formation and the wellbore annulus, the latter is obtained by integrating the instantaneous heat transfer. Equation 4.4 gives the cumulative heat transfer between the annulus and the drill pipe, and assumes that the temperature difference across the interface is constant for the entire length of the numerical segment.

$$\frac{dQ_{a-f}}{dt} = \frac{k_h A (T_f - T_a)}{r_w} \left\{ \left(\frac{\pi \alpha t}{r_w} \right)^{-\frac{1}{2}} + \frac{1}{2} - \frac{1}{4} \left(\frac{\alpha t}{r_w^2 \pi} \right)^{\frac{1}{2}} + \frac{1}{8} \left(\frac{\alpha t}{r_w^2} \right) \right\} \quad (4.1)$$

Equation 4.1: Instantaneous radial heat transfer from the formation to the wellbore annulus (Farouq Ali, 2012).

Where:

- k_h is the thermal conductivity [kW/mC]
- A is the surface area over which the heat transfer occurs [m²]
- T_f is the formation temperature [°C]
- T_a is the annulus temperature [°C]
- r_w is the radius of the wellbore [m]
- α thermal diffusivity of the formation [m²/s]
- t is the cumulative time over which the heat transfer occurs [s]

The thermal diffusivity is given by:

$$\alpha = \frac{k_h}{\rho_f C_f} = \frac{k_h}{M_s} \quad (4.2)$$

Equation 4.2: This equation gives the thermal diffusivity (Satter, 1967).

Where:

- k_h is the thermal conductivity [kW/mC]
- ρ_f is the density of the formation
- C_f is the heat capacity of the formation
- M_s is the volumetric heat capacity of the formation [kJ/m³C]

$$Q_{a-f} = \frac{k_h A (T_a - T_f)}{r_w} \left\{ 2 \left(\frac{\pi \alpha}{r_w^2} \right)^{-1/2} t^{1/2} + \frac{1}{2} t - \frac{1}{6} \left(\frac{\alpha}{r_w^2 \pi} \right)^{1/2} t^{3/2} + \frac{1}{16} \left(\frac{\alpha t^2}{r_w^2} \right) \right\} \quad (4.3)$$

Equation 4.3: Cumulative heat transfer from the formation to the wellbore.

$$Q_{p-a} = U_{pipe} A (T_a - T_p) t \quad (4.4)$$

Equation 4.4: Cumulative radial heat flow from the annulus to the drill pipe (Gudmundsson, 2009).

Where:

- U_{pipe} is the heat transfer coefficient (assumed to be constant throughout the drill pipe [kW/m²°K]
- A is surface area of the interface between the inside of the drill pipe and the annulus, which is the surface area inside the drill pipe [m²]
- ΔT is the temperature difference between the inside of the drill pipe and the annulus [°K]
- T_p is the drill pipe temperature [°C]
- t is the cumulative time that the heat transfer occurs [s]

The heat transfer across the interfaces will remove energy from one area (the one with at a higher temperature) and transfer it to another area (at a lower temperature). In the wellbore this means that heat will flow from one fluid volume to another. Circulating mud is assumed to fill these fluid volumes. Equation 4.5 yields the temperature change in the mud due to heat transfer.

$$\Delta T = \frac{Q}{mC_p} = \frac{Q}{V\rho C_p} \quad (4.5)$$

Equation 4.5: Temperature change in the mud (Gudmundsson, 2009).

Where:

- T is temperature [°C]
- Q is the heat transferred [J]
- m is the mass of the fluid in the specific volume [kg]
- V is the fluid volume [m³]
- c_p is the heat capacity of the fluid [J/kgK]
- ρ is the density of the fluid [kg/m³]

Heat is also generated in the wellbore due to mechanical friction from the drill pipe in contact with the wellbore (Equation 3.5, Equation 3.6) and the grinding action of the rotating bit against the formation (Equation 3.7). The heat generation from drill pipe friction against the formation is assumed negligible since the model is for a vertical well where the heat generation from this effect is very low. The final heating effect is due to pressure drop caused by viscous friction in the drill pipe and annulus (Equation 3.3) and pressure drop over the drill bit (Equation 4.6).

$$\Delta P_{bit} = 1.1 \cdot \frac{1}{2} \cdot \rho \cdot v^2 = 0.55 \cdot \rho \cdot \left(\frac{q}{A_{nozzles}} \right)^2 \quad (4.6)$$

Equation 4.6: The pressure drop over the drill bit (Skalle, 2012).

Where:

- v is the fluid velocity out of the bit [m/s]
- q is the circulation rate [m³/s]
- $A_{nozzles}$ is the total surface area of the bit nozzles [m²]

The equations presented in this section for the heat transfer, heat generation and heating effects in the well will be used in the next section to construct the numerical model that will be simulated in Matlab.

4.3 Constructing the Numerical Model

In this section the assumptions mentioned in section 4.1 are combined with the equations for heat transfer and heat generation in the wellbore covered in section 4.2 to develop a numerical model. The wellbore has been divided into segments with a height of 1 meter, one segment for the drill pipe and one segment for the annulus (Figure 21). The two segments are in contact with each other through the wall of the drill pipe, and the surface area of the drill pipe is the heat transfer area between the two separated fluid volumes. The fluid pumped downwards in the drill pipe is colder than the fluid in the annulus, which is pumped upwards towards the surface, represented by the blue and red arrows on Figure 21, respectively. The drill pipe fluid temperature is lower because of the surface mud cooling, while the annulus have been heated by heat transfer effects and other heat generation mechanisms in the wellbore.

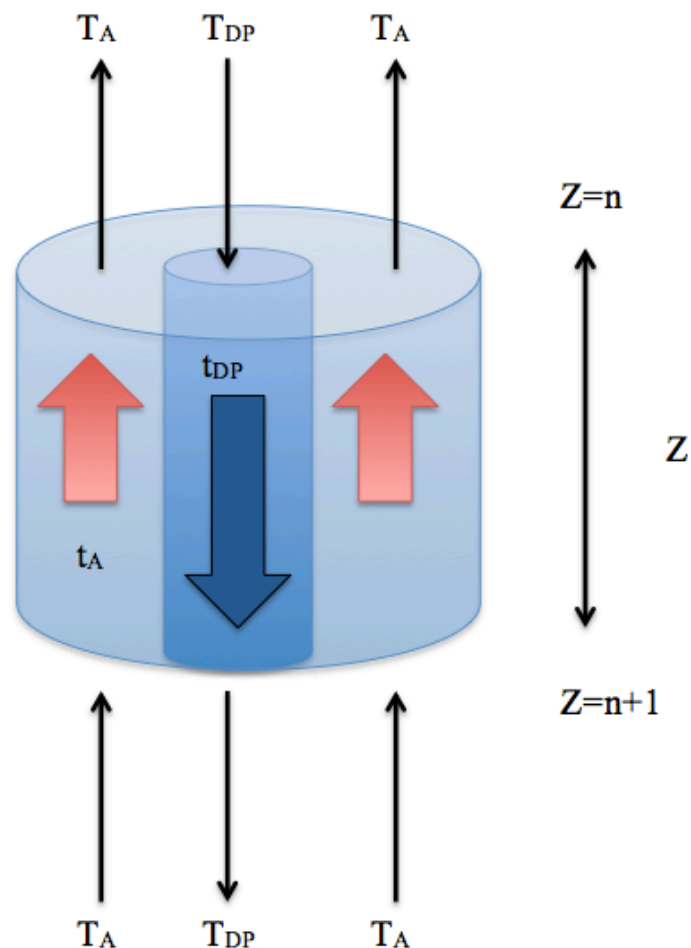


Figure 21: Illustration of the numerical segment used in the model.

4.3.1 Staying Time in Each Numerical Segment

Equation 4.7 and Equation 4.8 gives the time that the circulating mud stays in each segment, referred to as the staying-time. The staying-time in each segment is shown on Figure 21 for the annulus and drill pipe as t_A and t_{DP} , respectively. This is the time period that the fluid volume in the segment is exposed to heat transfer with its surroundings. The difference in staying-time between the drill pipe and the annulus is a consequence of the difference in volume.

$$t_{drillpipe,segment} = \frac{V_{drillpipe,segment}}{q} \quad (4.7)$$

Equation 4.7: Staying time in each drill pipe segment.

Where:

- $t_{drillpipe,segment}$ is the staying-time in the drill pipe segment [s]
- $V_{drillpipe,segment}$ is the fluid volume in one drill pipe segment [m^3]
- q is the fluid flow rate [m^3/s]

$$t_{annulus,segment} = \frac{V_{annulus,segment}}{q} \quad (4.8)$$

Equation 4.8: Staying-time in each annulus segment.

Where:

- $t_{annulus,segment}$ is the staying-time in the annulus segment [s]
- $V_{annulus,segment}$ is the fluid volume in one annulus segment [m^3]

4.3.2 Heat Transfer

The heat transfer between the formation and the annulus, and the annulus and the inside of the drill pipe gives the internal energy change in each segment ($\Delta Q_{drillpipe}$ and $\Delta Q_{annulus}$). Equation 4.9 and Equation 4.10 gives the temperature change in each segment as a consequence of the change in internal energy.

$$\begin{aligned}\Delta T_{drillpipe} &= \frac{\Delta Q_{drillpipe}}{mC_p} = \frac{\Delta Q_{drillpipe}}{V_{drillpipe,segment}\rho C_p} \\ &= \frac{Q_{annulus \rightarrow drillpipe}}{V_{drillpipe,segment}\rho C_p}\end{aligned}\quad (4.9)$$

Equation 4.9: The temperature change in the drill pipe due to the change in the internal energy of the mud (Gudmundsson, 2009).

Where:

- $\Delta Q_{drillpipe}$ is the net heat entering the drill pipe [J]
- $Q_{annulus \rightarrow drillpipe}$ is the heat transfer from the annulus to the drill pipe in each segment [J]

$$\begin{aligned}\Delta T_{annulus} &= \frac{\Delta Q_{annulus}}{mC_p} = \frac{\Delta Q_{annulus}}{V_{annulus,segment}\rho C_p} \\ &= \frac{Q_{formation \rightarrow annulus} - Q_{annulus \rightarrow drillpipe}}{V_{annulus,segment}\rho C_p}\end{aligned}\quad (4.10)$$

Equation 4.10: The temperature change in the annulus due to the change in the internal energy of the mud (Gudmundsson, 2009).

Where:

- $\Delta Q_{annulus}$ is the net heat entering the annulus [J]
- $Q_{formation \rightarrow annulus}$ is the heat transfer from the formation to the annulus [J]

$Q_{annulus \rightarrow drillpipe}$ is the heat transfer between the annulus and the drill pipe, while $Q_{formation \rightarrow annulus}$ is the heat transfer between the formation and the annulus. Both these parameters are shown in Figure 22, which is the figure displaying how the Matlab model has been built up.

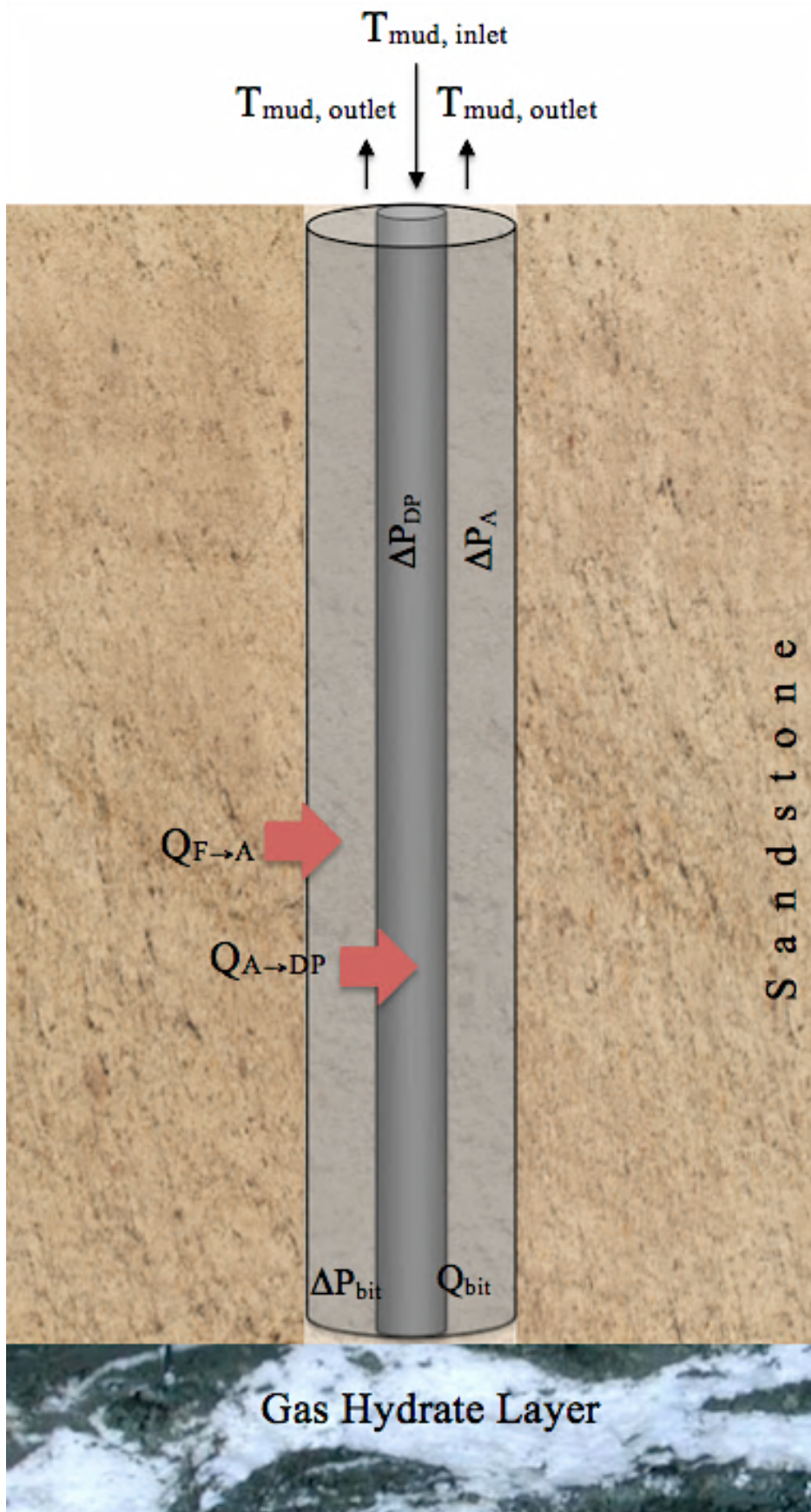


Figure 22: Illustration of the model used to construct the numerical model and perform the Matlab simulation.

4.3.3 Formation, Initial Drill Pipe and Initial Annulus Temperature Distribution

This section will present the equations that were developed for the initial temperature distribution of the formation, drill pipe and annulus as a function of depth. These equations do not include heat transfer. The formation temperature is a function of the temperature at the surface (onshore drilling) or seabed (offshore drilling), the geothermal gradient and the depth, and is given by the following equation:

$$T_{formation} = T_{surface} + \text{Geothermal gradient} \cdot \frac{Z}{1000} \quad (4.11)$$

Equation 4.11: The formation temperature distribution.

Where:

- $T_{surface}$ is the temperature at the surface of the overburden, either the temperature at the surface of the ground (onshore) or at the seabed (offshore).
- Z is the depth of the formation, measured from the surface [m]
- Geothermal gradient [$^{\circ}\text{C}/\text{km}$]

The initial drill pipe temperature distribution depends on the temperature of the mud entering the drill pipe at the surface and the temperature increase due to pressure loss in the drill pipe, and is given by the following equation:

$$\begin{aligned} T_{drillpipe,initial}(Z) &= T_{drillpipe,inlet} + \Delta T_{\Delta P,drillpipe}(Z) \\ &= T_{drillpipe,inlet} + \frac{-\Delta P_{drillpipe}}{\rho_{mud} C_p} \end{aligned} \quad (4.12)$$

Equation 4.12: The initial temperature distribution in the drill pipe.

Where:

- Z denotes the depth of the numerical segment in the well [m]
- $T_{drillpipe,inlet}$ is the temperature of the mud when entering the drill pipe at the surface [$^{\circ}\text{C}$]
- $\Delta T_{\Delta P,drillpipe}$ is the temperature change as the result of pressure losses in the drill pipe [$^{\circ}\text{C}$]

The initial annulus temperature distribution is a function of the temperature increase due to pressure losses in the entire drill pipe, the temperature increase due to heat generated by the mechanical action of the bit and pressure loss over the bit, and the pressure loss in the annulus. It is given by the following equation:

$$\begin{aligned}
 T_{annulus,initial}(Z) &= \Delta T_{total\ drillpipe\ \Delta P\ losses} + \Delta T_{bit} \\
 &+ \Delta T_{bit\ \Delta P\ losses} + \Delta T_{annulus\ \Delta P\ losses} \\
 &= \frac{-\Delta P_{drillpipe,ps} \cdot depth}{\rho C_p} + \frac{Q_{bit} \cdot t_{annulus,segment}}{V_{annulus,segment} \rho C_p} \quad (4.13) \\
 &+ \frac{-\Delta P_{bit}}{\rho C_p} + \frac{-\Delta P_{annulus,ps} \cdot (depth - Z)}{\rho C_p}
 \end{aligned}$$

Equation 4.13: The initial temperature distribution in the annulus.

Where:

- $\Delta T_{total\ drillpipe\ \Delta P\ losses}$ is the total pressure loss through the entire drill string [°C]
- ΔT_{bit} is the temperature increase from the heat generated by the mechanical action of the bit [°C]
- $\Delta T_{bit\ \Delta P\ losses}$ is the temperature increase from the heat generated by the pressure loss over the bit (through the nozzles) [°C]
- $\Delta T_{annulus\ \Delta P\ losses}$ is the pressure loss due to friction in the annulus [°C]
- $\Delta P_{drillpipe,ps}$ is the pressure loss in the drill pipe per segment [Pa]
- $\Delta P_{annulus,ps}$ is the pressure loss in the annulus per segment [Pa]
- $depth$ is the total depth of the well [m]

4.4 Simulation Parameters and Their Values

This section covers the parameters and assumptions used in the simulation. Several of the parameter values are taken from Kallhovd et al. (2012) as these are typically industry values and are applicable in this situation as well.

4.4.1 Calculating the Volumetric Heat Capacity and Thermal Diffusivity of the Formation

The Matlab model simulates the annulus temperature distribution at the instant when a HBL is encountered. This means that practically the entire formation consists of sandstone with no GH content, which is why the volumetric heat capacity and the thermal diffusivity is calculated for a sandstone formation, instead of for a GH reservoir. The following parameters necessary to calculate the volumetric heat capacity of the formation and the thermal diffusivity have been found (EngineeringToolBox, 2013):

Type	Value	Unit
Porosity	0.25	NA
Density of the pore fluid (assumed to be water)	1000	kg/m ³
Heat capacity of water (at T=5 Celsius)	4.204	kJ/kgK
Density of sandstone	2350	kg/m ³
Heat capacity of sandstone	0.92	kJ/kgK
Thermal conductivity of sandstone (k_h)	0.0017	kW/mK

Table 1: The parameters and their values necessary to calculate the volumetric heat capacity and the thermal diffusivity of the formation.

The volumetric heat capacity of the formation is given by:

$$M_s = \varphi \cdot \rho_{fluid} \cdot C_{P_{fluid}} + (1 - \varphi)\rho_{bulk}C_{P_{bulk}} \quad (4.14)$$

Equation 4.14: Volumetric heat capacity of the formation (Kallhovd et al., 2012).

Where:

- φ is the porosity [dimensionless]
- ρ_{fluid} is the density of the pore fluid [kg/m³]
- $C_{P_{fluid}}$ is the heat capacity of the pore fluid [kJ/kgK]
- ρ_{bulk} is the bulk density of the formation [kg/m³]
- $C_{P_{bulk}}$ is the heat capacity of the bulk formation [kJ/kgK]

Calculating the volumetric heat capacity of the formation yields:

$$\begin{aligned}M_s &= \varphi \cdot \rho_{fluid} \cdot C_{P_{fluid}} + (1 - \varphi)\rho_{bulk}C_{P_{bulk}} \\&= 0.25 \cdot 1000 \frac{kg}{m^3} \cdot 4.204 \frac{kJ}{kgK} + (1 - 0.25) \cdot 2350 \frac{kg}{m^3} \cdot 0.92 \frac{kJ}{kgK} \\&\approx 2673 \frac{kJ}{m^3K}\end{aligned}$$

Calculating the thermal diffusivity with Equation 4.2 yields:

$$\alpha = \frac{k_h}{M_s} = \frac{0.0017 \frac{kJ}{kgK}}{2673 \cdot \frac{kJ}{m^3K}} = 0.636 \cdot 10^{-6} \frac{m^2}{s}$$

4.4.2 Parameter List

This table lists all the parameters that have been used in the numerical simulation.

Type	Value	Unit
Surface mud temperature at the drill pipe inlet	0	°C
Surface temperature	0	°C
Geothermal gradient	20	°C/km
Porosity (φ)	0.25	NA
Density of the pore fluid (assumed to be water) (ρ_{fluid})	1,000	kg/m ³
Heat capacity of the pore fluid (assumed to be water at 5°C)	4.204	kJ/kgK
Density of sandstone (ρ_{bulk})	2,350	kg/m ³
Heat capacity of sandstone ($C_{P_{bulk}}$)	0.92	kJ/kgK
Thermal conductivity of sandstone (k_h)	0.0017	kW/mK
Volumetric heat capacity of the formation (M_s)	2,673	kJ/ m ³ K
Thermal diffusivity of sandstone (α)	$0.636 \cdot 10^{-6}$	m ² /s
Hole diameter (17.5 inches)	0.4445	m
Outer diameter of the drill pipe (6 5/8 inches)	0.1683	m
Inner diameter of the drill pipe (6 1/6 inches)	0.1566	m
Drilling depth	1,200	m
Circulation rate (2000 liters per minute)	0.0333	m ³ /s
Drill pipe heat transfer coefficient	0.02	kW/m ² K
Density of the mud	1,100	kg/m ³
Heat capacity of the mud	4.210	kJ/kgK
Drill pipe pressure loss (ΔP per meter)	$0.04 \cdot 10^5$	Pa/m
Annulus pressure loss (ΔP per meter)	$0.02 \cdot 10^5$	Pa/m
Drill bit nozzle surface area	$6.8 \cdot 10^{-4}$	m ²
Weight on bit (WOB) (2000 kg)	19,620	N
Drill bit torque	4,000	Nm
Drill pipe rotation per second (150 rotations per minute)	2.5	1/s
Bit efficiency (β)	0.7	NA

Table 2: A summary of all the parameters used in the numerical simulation.

4.5 Results

Figure 23 shows the results for simulating the initial temperature of the formation, drill pipe and annulus of the Matlab program. The temperature in the drill pipe increases gradually towards the depth of the well as a consequence of pressure loss in the drill pipe, which generates heat. At the bottom the mud is heated by roughly one degree because of pressure loss over the bit and heat generated by the mechanical action of the bit against the formation. The temperature increases steadily in the annulus as the mud flows to the surface due to pressure loss in the annulus. In this initial step of the simulation, heat transfer has not yet been included. This step in the simulation is only done to generate the initial values of the formation, drill pipe and annulus for all segments from the surface to the depth of the well.

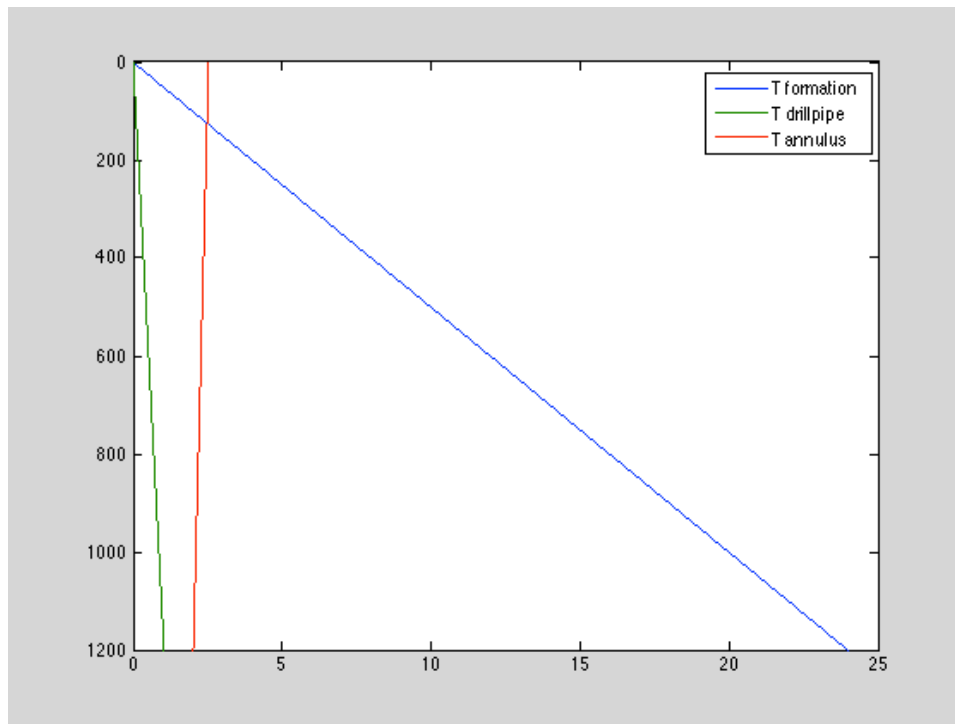


Figure 23: This graph shows the formation, initial drill pipe, and the initial annulus temperature distribution while drilling at 1,200 meters depth.

4.6 Discussion

No results have been created for the main simulation of the temperature distribution in the annulus during drilling into a HBL at a specific depth because the simulation itself was unfortunately unsuccessful due to issues with implementing the model in matlab (creating the code). Although the necessary equations were presented in section 4.2, and the model was developed in section 4.3, programming equations Equation 4.12 and Equation 4.13 in Matlab as a function of both time and depth proved unsuccessful. However, improvements to the model have been made (4.7), along with suggestions for how the model can be further improved (4.8). The complete code for the Matlab program developed is found in Appendix B – Matlab Program.

4.7 Improvements Compared to the Previous Model

The improvements made in this model compared to the previous model, has been to include a complicated and realistic calculation of the initial values of the formation, drill pipe and annulus (Figure 23).

4.8 Further Work

The following can be included in the Matlab model to improve accuracy and realism, and is therefore suggested as further work:

- The effect of a riser to enable the simulation of offshore drilling
- Heat generation due to friction between the drill string and the formation (mechanical drag forces), so that the model can be used for deviated wells
- Non-constant formation temperature, a formation temperature that changes as a consequence of heat transfer with the annulus
- Radiation heat transfer
- Drill collars, instead of assuming that the drill string has a constant OD
- Continuous drilling, instead of stationary drilling at a specific depth
- Permeable borehole, which means that fluid flow between the formation and annulus will have to be taken into account
- Decreasing the size of the numerical segments
- Dependability of mud properties

5 Gas Production from Gas Hydrate Deposits

Gas production from GH reservoirs poses a number of new and unique challenges in respect to achieving economical gas production rates compared to conventional and also other unconventional gas reservoirs. After drilling, casing and completing a conventional gas well the reservoirs pressure will generally be sufficiently high for the gas to flow freely from the reservoir and up through the production tubing to the surface without the aid of a pumping system. Since GHs are solid, and are stable in the reservoir, achieving commercial gas production rates are not as straightforward.

5.1 Methods of Inducing Gas Hydrate Dissociation

The four main methods for producing gas from GH reservoirs are:

- i. Depressurization
- ii. Thermal injection
- iii. Inhibitor injection
- iv. CO₂ injection.

Although many other methods exist, such as injection acids and bases to create an exothermic reaction in the reservoir, or combinations of the main methods, these four main methods will be the focus of this section. The first three methods produces gas by initiating and controlling a slow endothermic dissociation process in the reservoir, where the necessary heat is either taken from the reservoir and/or its surroundings, or supplied externally. The last method is a new emerging technology that produces gas by injecting CO₂ into the reservoir where it replaces the natural gas molecules in the GHs clathrate (mainly methane) in an exothermal process.

The first three methods are conventional, extensively tested and widely utilized methods which act by changing the thermodynamic stability of the GHs. The first two methods act by changing the P&T conditions, and the third by depressing the hydrate equilibrium temperature, meaning that the upper temperature at which the GHs are stable is reduced. Both these changes will, in sufficient amounts, cause the GHs in the reservoir to become unstable and dissociate. The rate of hydrate dissociation or gas release with these methods will be dominated by the limitations imposed by mass and

heat transfer, since kinetics of the hydration/dissociation equation is only important for short-term dissociation process lasting a few minutes to a few hours.

5.1.1 Depressurization

Conventional gas production is characterized by drilling a production well into a pressure gas reservoir and subsequently allowing the gas to flow to the surface towards the lower pressure. The gas production rate is controlled by changing the pressure at the surface. This method is called depressurization and is also applicable to a GH reservoir.

During depressurization, dissociation of the GHs is induced in the reservoir by reducing the reservoir pressure sufficiently to drop below the stability pressure of the GHs at the specific temperature in the reservoir. This is shown in Figure 24. The reduction in reservoir pressure perturbs the GH stability curve, changing it to the left. This means that a lower reservoir temperature is required before the GHs can become stable again. Assuming that the pressure is held constant at the reduced pressure, the GHs will dissociate until the temperature in the reservoir reaches the new stability temperature. The dissociation process, and the gas production rate, can be maintained by reducing the wellbore pressure (which caused a pressure reduction in the reservoir) as the reservoir temperature decreases.

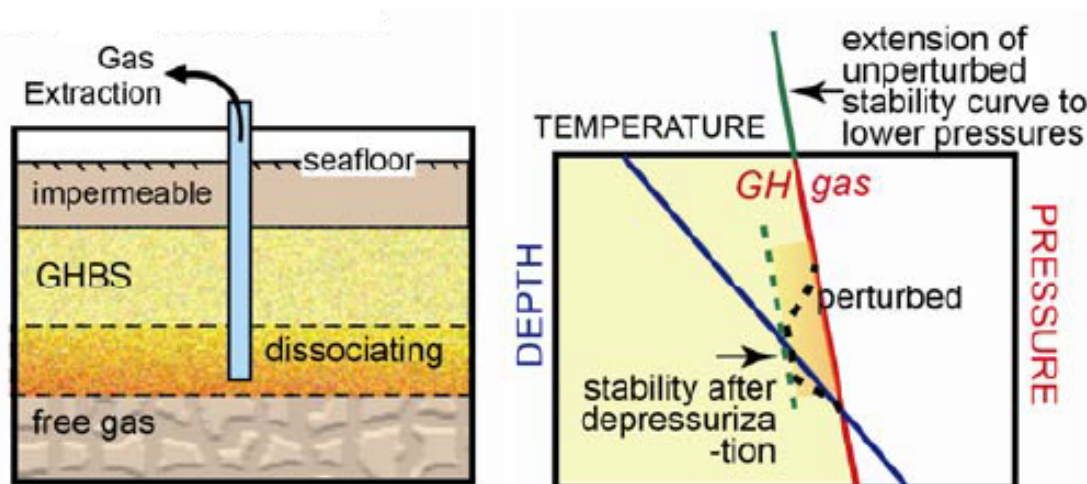


Figure 24: Gas production from GH reservoirs by depressurization (Khameneh et al., 2012).

The production of mobile reservoir fluids (generally water and gas) from the drilled and completed production well generates pressure waves that can propagate through the reservoir (reducing the pressure throughout the reservoir) and cause instability and dissociation of GHs far from the wellbore. Complicating factors with this production method is the formation of secondary solids (ice and reformed GHs) near the wellbore

area due to the high pressure and temperature drop near the producing wellbore. The high pressure drop at this location leads to significant GH dissociation, which due to the endothermic nature of the reaction absorbs significant amounts of heat from its surroundings. The formation of secondary solids will have a detrimental effect on the formation permeability and gas production rate if this issue is not resolved (Moridis et al., 2008).

The depressurization method is the preferable choice out of the production methods based on its simple, economically effective and technically effective production method that does not require complicated equipment. There is also no heat requirement as the necessary dissociation heat is taken from the reservoir and/or is surroundings, and there are also no chemicals involved.

5.1.2 Thermal Stimulation

Producing gas from GHs through thermal stimulation simply involves raising the temperature of the GHs above the equilibrium point through heating, which will cause the GHs to become unstable and dissociate (Figure 25). Gas production from GHs by thermal stimulation alone is referred to as “pure thermal stimulation.” The heat can be supplied by a variety of processes: electromagnetic, an exothermic reaction, mechanical or injection of a warm fluid, to name a few. Common thermal stimulation methods include steam injection, hot water injection, hot brine (saline solution) injection, electrical wellbore heating and fire flooding.

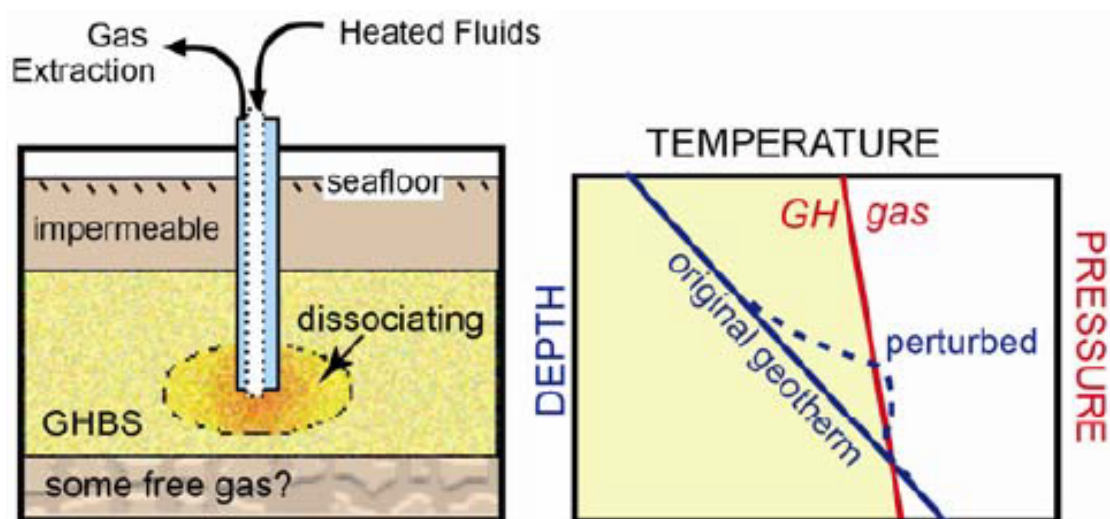


Figure 25: Gas production from GH reservoirs by thermal injection (Khameneh et al., 2012).

Thermal stimulation can be used in conjunction with other production methods, which it often is, mainly to prevent the formation of secondary solids (ice and reformation of GHs near the wellbore).

If losses to the surroundings are ignored and only the energy required for dissociation is taken into account as a heat loss, then the energy required for dissociation equals 6.12% of the energy contained in the free gas (see section 2.3.2 for further information on the calculation), meaning that this process has a favorable net energy balance. However, this is a major simplification as there will be significant inefficiencies in the system (Moridis et al., 2008). Some of these inefficiencies is unintended heating of the formation rock (the bulk density of the formation), water and ice in the pore-space, gas and water that has already been released from produced GHs, and water in underlying water zone.

Thermal stimulation is generally regarded as slow (due to the slow propagation of heat in the reservoir), energy intensive and inefficient/wasteful (large losses downhole through the boundary, to the rock formation and other reservoir fluids). Injected fluids, which have a heat-transfer mechanism that act by advection, could have a negative impact on the relative permeability of gas and reduce the gas production rate. Heat-transfer based on conduction is on the other hand significantly slower and less efficient (such as electrical heating), and is therefore not a good choice for pure thermal stimulation. Although pure thermal stimulation is deemed unsuited as a gas production method from HBLs, it can be quite effective when used in conjunction with depressurization for near wellbore applications to reduce or prevent the formation of secondary solids (Moridis et al., 2008).

5.1.3 Inhibitor Injection

Injecting thermodynamic GH inhibitors (such as methanol, glycol, MEG and TEG) in the wellbore shifts the GH equilibrium curve to the left, then the depression of the GH equilibrium curve below the stability pressure, will causes the GH to dissociate (Figure 26). The presence of inhibitors reduces the stability of the GHs by entering the local pore water and changing its chemical composition, causing it to be unstable to GHs. If a large enough inhibitor quantity is present, it will cause a sufficient temperature depression in the equilibrium/stability-temperature of the GHs (the pressure at which the GHs are stable at the specific pressure in the reservoir) that it will cause dissociation

of the GHs. An example of this is shown in Figure 27 where the effective GH equilibrium temperature depression of methanol and MEG is shown as a function of methanol and MEG added by weight% (left figure) and volume% (right figure). By looking at the weight % chart (left figure), it is obvious that methanol has a much higher temperature depression than MEG for most of the inhibitor concentration. When looking at the inhibitor concentration as a function of volume% the difference is much smaller (Steinbakk, 2012).

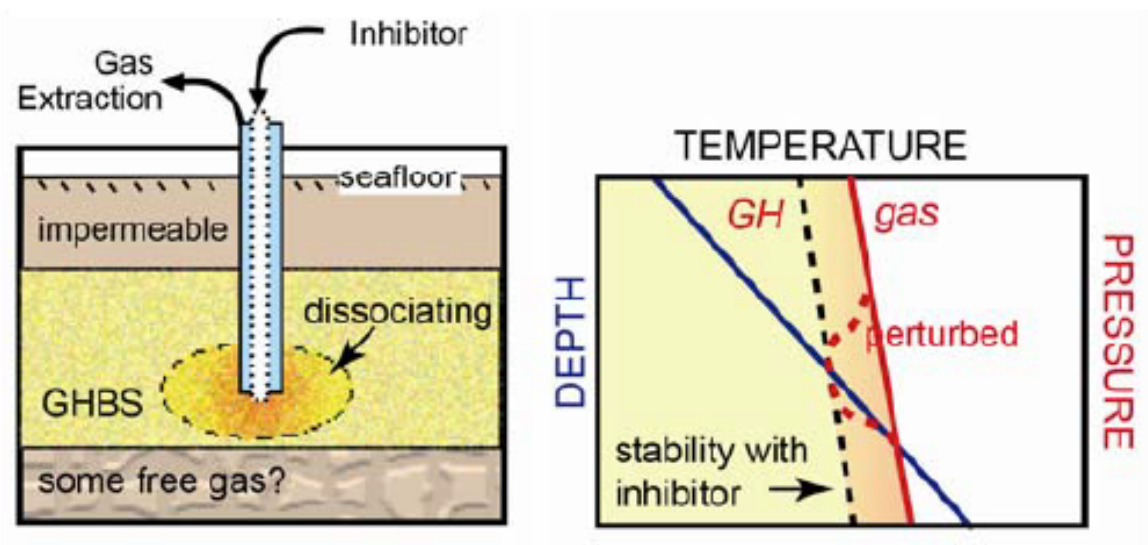


Figure 26: Gas production from GH reservoirs by inhibitor injection (Khameneh et al., 2012).

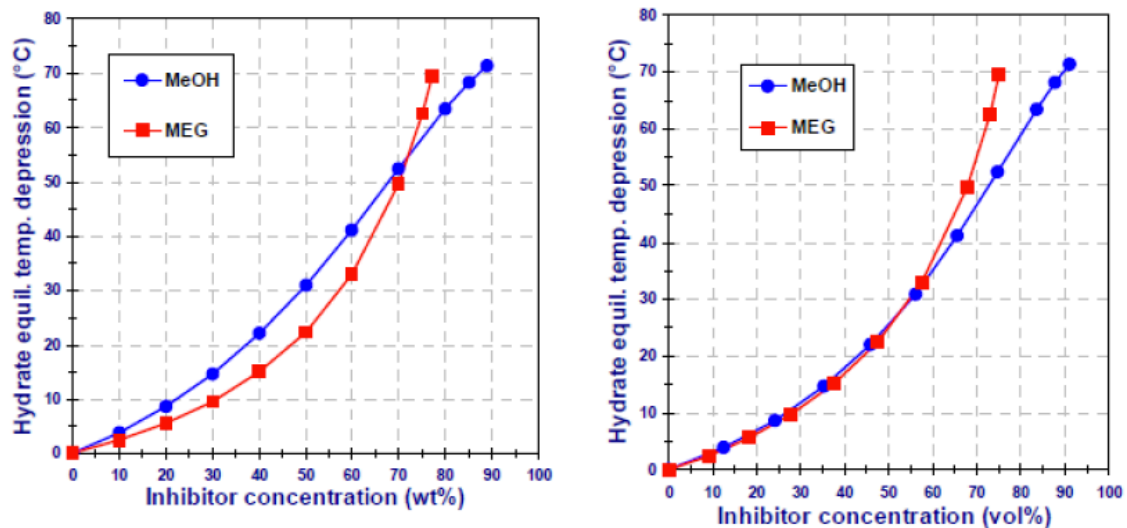


Figure 27: Equilibrium temperature depression in GHs due to addition of thermodynamic inhibitors (Steinbakk, 2012).

An advantage of using inhibitor injection is that this would prevent formation of GHs in the production pipeline and at wellhead during production. The injected inhibitors will contaminate the produced gas and decontamination will increase the associated production cost. The main reasons why inhibitor injection is unsuited for GH production are environmental, economic and related to efficiency. These chemicals are required in huge quantities to cause the desired dissociation in the reservoir and will contaminate the produced gas, which requires decontamination thus increasing the cost. Many of the chemicals used are also harmful to the environment, difficult or nearly impossible to regenerate, and generally quite ineffective in causing dissociation in the reservoir due to the release of water from the dissociation reaction and possibly produced water from the reservoir diluting the inhibitors (causing a rapid reduction in effectivity). All these factors lead to the conclusion that inhibitor injection is not a recommended pure/primary production method to produce GH reservoirs (Moridis et al., 2008).

5.1.4 CO₂ Injection

This new and emerging technology involves injecting CO₂ into the GH reservoir where the CO₂ molecules replace the natural gas molecules (mainly methane) in the clathrate structure. Other thermodynamic molecules could also be used. According to Lee et al. (2003), 64% of the methane in the GH reservoir could be exchanged with CO₂ and recovered with this production method. The three main advantages of this method are:

1. The replacement of the natural gas molecule is an exothermic reaction and thus generates heat in the reservoir
2. The mechanical stability of the reservoir is maintained since the GHs are not dissolved
3. It sequesters CO₂, which is a greenhouse gas

The main disadvantages of this method are the requirement to transport a significant quantity of CO₂ to the wellbore where it is stored and injected when necessary. The rate of production and cumulative gas production volume seems to be limited with this method according to some studies (Lee et al., 2003). Although this is an interesting method of production, significant R&D efforts are necessary before being used for commercial gas production from GH reservoirs.

5.2 Classification of Gas Hydrate Deposits

Classifying the GH deposits is important because it gives valuable insight into which production method that is optimally suited for the characteristics of each deposit type. There are three main classes of GH deposits classified by their initial reservoir conditions and simple geological features (Moridis et al., 2008); Class 1 deposits, Class 2 deposits and Class 3 deposits.

5.2.1 Class 1 Deposit

Two separate layers make up Class 1 deposits: an upper hydrate-bearing layer and a lower two-fluid zone with mobile gas and liquid water in the pore space (Figure 28). Class 1 deposits, also referred to as “hydrate-capped gas reservoirs”, are again classified into two types of deposits on basis of the pore content of the GH zone: water and GH in the first (Class 1W), and gas and GH in the second (Class 1G). The gas content in the GH zone above the free gas zone in the Class 1G deposit confirms that the lower limit of the GHSZ coincides with the bottom of the GH zone, which means that the GHs in the reservoir is close to the GH equilibrium curve and that the GH reservoir can be easily destabilized, especially compared to the Class 1W deposit (Moridis et al., 2008).

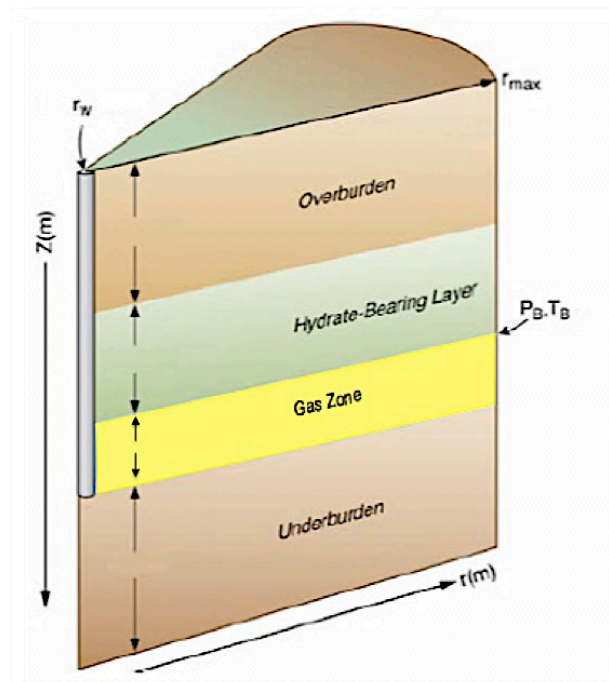


Figure 28: Illustration of a class 1 deposit showing the upper HBL and the lower gas zone. P_B and T_B are the boundary pressure and temperature between the HBL and the gas zone (illustration modified from Moridis et al., 2008).

5.3 Class 2 Deposit

The class 2 deposits are made up of two separate layers: an upper hydrate-bearing layer and a lower zone of mobile water (Figure 29). Inducing dissociation of the GHs in this type of deposit can be difficult because the entire HBL can exist under equilibrium or stable conditions.

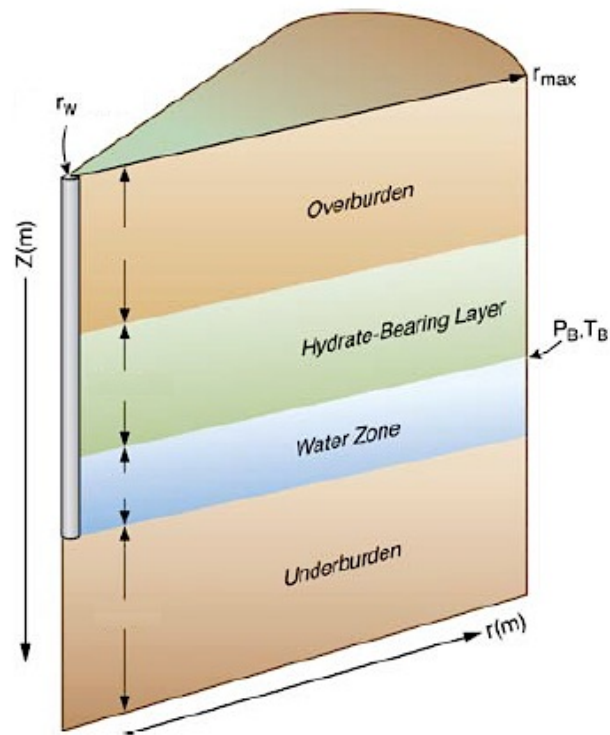


Figure 29: Illustration of a class 2 deposit showing the upper HBL and the lower mobile water zone. P_B and T_B are the boundary pressure and temperature between the HBL and the mobile water zone (Moridis et al., 2008).

5.3.1 Class 3 Deposits

This type of deposits contains only a single layer, which is the HBL, and a lack of mobile fluids in the underlying zone (Figure 30). Inducing dissociation of the GHs in this type of deposits can be difficult because the entire HBL can exist under equilibrium or stable conditions.

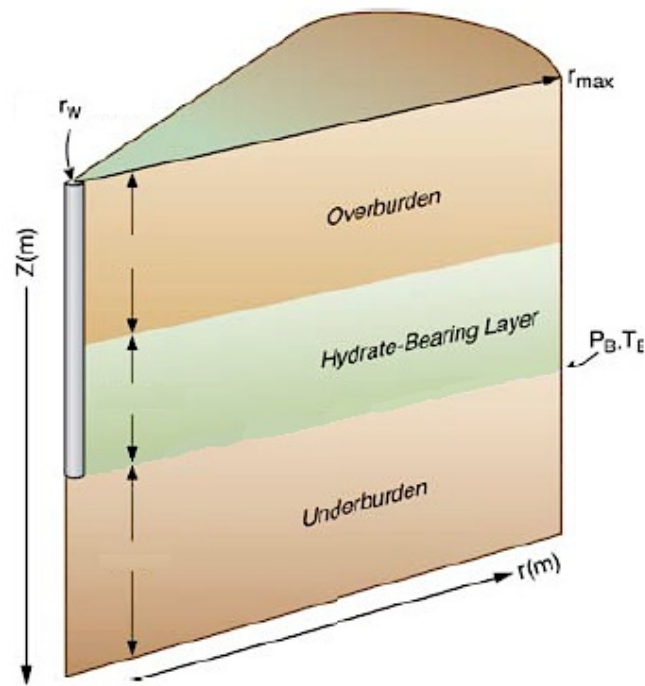


Figure 30: Illustration of a class 3 deposit showing HBL and the lack of mobile fluids in the underlying zone (only underburden). P_B and T_B are the boundary pressure and temperature between the HBL and underburden (illustration modified Moridis et al., 2008).

5.4 Gas Production Strategies From Gas Hydrate Deposits

This section will cover the optimal gas production strategy for each of the three types of deposits.

5.4.1 Class 1 Deposit

The practically immediate response of GHs to propagating pressure waves compared to the significantly slower response to thermal stimulation, combined with the ability of the underlying gas layer to quickly react to and distribute pressure changes in the reservoir to the HBL, means that the dissociation methods will provide both high production rates and a large cumulative production volume. Since this method is also simple and technically and economically effective, out of the three main dissociation methods, the depressurization strategy appears to be the one best suited.

The effectiveness of the depressurization production method in this type of reservoir will cause a high dissociation GH rate, which requires a significant amount of heat (the dissociation reaction is endothermic), especially where the pressure drop is at its highest. The high pressure drop near the producing zones of the wellbore will lead to very high dissociation rates and heat requirements and the temperature might therefore drop below the GH stability points or the freezing point of water. There is therefore a high risk of formation of solid phases, also referred to as secondary GH and ice, in the area near the producing zones of the wellbore due to the significant pressure and temperature drop.

The formations of solids will have an unfavorable impact on the fluid permeability regime and a detrimental effect on the gas production (choke the well). Although counterintuitive when producing a reservoir by depressurization, positioning the top of the production interval (the perforated interval) at a sufficient distance from the initial GH interface (the transition between the HBL and the gas layer) has the ability to reduce the consequences of this problem and significantly enhance long-term production from GHs, although heating the producing sections of the wellbore will be necessary to avoid blockage (Moridis et al., 2007; Moridis et al., 2008). With sufficient heating the top of the production interval could also be positioned closer to the initial hydrate interface without experiencing blockage.

At the same time as the original dissociation front (GH interface) will move upwards as it dissociates during production, a new dissociation front will develop at the

top of the HBL and move downwards at the same time, both for Class 1G and Class 1W deposits. Class 1G deposits will have a continuous increasing dissociation rate during production while the dissociation rate of Class 1W deposits will progress in distinct stages. For Class 1G deposits, the GHs accounts for up to 75% of the production rate and 54% of the cumulative volume of produced gas, the same numbers for Class 1W deposits are 65% and 45%. In essence, Class 1G deposits are both faster and simpler to produce from than Class 1W deposits (all other properties being equal). The three main reasons why Class 1 deposits are considered the most promising target for gas production are (Moridis et al., 2007):

1. Conventional technology can be used with the depressurization method to achieve high gas production rates over a long time period
2. The economic risks associated with this type of deposit are significantly reduced because even if the contribution to the gas production rate and cumulative gas production volume from the HBL is small, the existence of a free-gas layer guarantees gas production nonetheless
3. The bottom of the HBL coincides with the bottom of the GHSZ, meaning that the GHs are easily destabilized

5.4.2 Class 2 Deposits

The recommended production method for these types of deposits is depressurization. The reasons are mainly the same as for Class 1 deposits: fast hydrate response to the rapid pressure wave propagation (aided by the near-compressibility of the underlying water zone which can quickly distribute the pressure reduction to the HBL), it is simple and technically and economically effective. The large heat capacity of water means that the underlying water zone can provide heat to sustain the endothermic dissociation reaction at the GH interface. Thermal stimulation for localized application to prevent secondary GH and ice near the producing interval of the wellbore is recommended for this class as well, although pure thermal stimulation is not recommended because it appears to be slow, ineffective, wasteful and might have an adverse affect on the relative permeability of the free gas near the producing interval. Inhibitor injection is discarded based on the following three reasons: risk of halite precipitation when using salt-based inhibitors, high cost of chemical inhibitors, and low overall effectiveness of

inhibitors caused by a rapid reduction in effectivity due to the release of water from the dissociation reaction and produced water from the water zone (Moridis et al., 2008).

Moridis et al. (2008) proposes a specific well design to optimize the production of Class 2 deposits by maximizing the area of all three of the GH dissociation interfaces (lower, cylindrical and upper) and avoid the formation of secondary GHs in the near wellbore area (generally within a radius of 10 meters around the producing interval) (Figure 31). The formation of secondary GHs and ice has a detrimental affect on both the gas production rate and the cumulative gas production volume and must be avoided. It is important to note that this well design does not exceed current technical capabilities.

The first phase shows the well design used during the initial production stages. The perforated production interval starts at the base of the HBL and extends 5 meters into the water zone. This is done to ensure sufficiently high initial flow rates in the well since the permeability of the HBL is very low, which is caused by high GH saturation in the pore volume. The outer surface of the wellbore is also heated during the initial production stages, preferable by warm water injection in the upper parts of the wellbore, but can also be done by electrical heating if the GH saturation of the formation is sufficiently high to make the flow of injected warm water difficult (phase 1 in Figure 31 shows the use of electrical heating). As shown in phase 1 in Figure 31, this heating dissociates the GHs in a cylindrical area around the wellbore creating an area of locally enhanced permeability that provides continuous communication with both the rising lower dissociation interface and the expanding cylindrical dissociation interface. This communication would likely not occur without outer wellbore heating due to the formation of secondary GHs and/or ice. Phase 2 involves injecting warm water into the formation at the top of the HBL. Phase 3 is initiated in the late stages of production, generally when less than 35% of the original GH volume remains and when there the gas accumulation on top of the reservoir is significant. It involves alternating zones between injecting warm water at low rates and producing from the upper hydrate dissociation interface without developing ice and/or secondary GHs (phase 3 might not be required).

Production from class 2 deposit

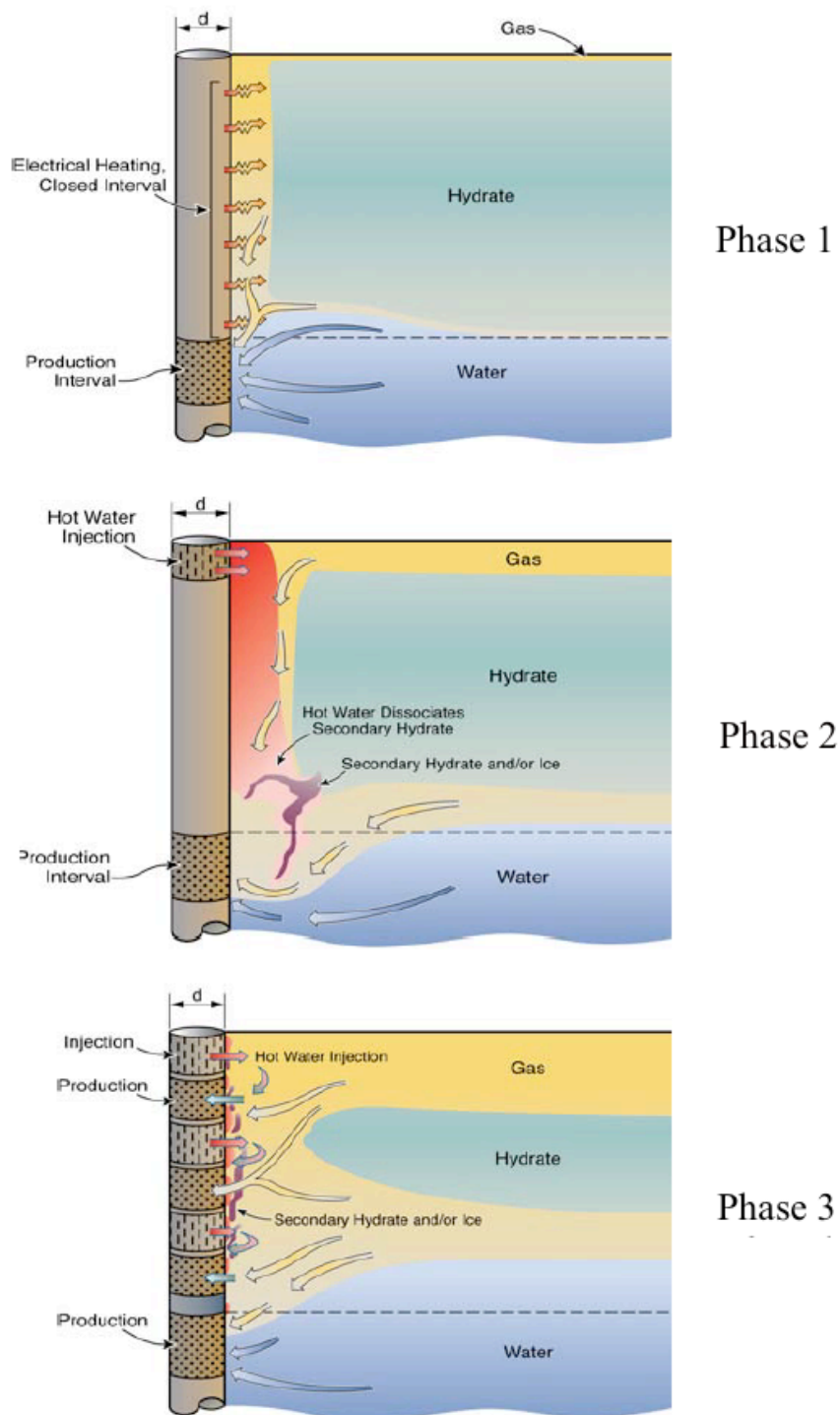


Figure 31: The figure shows the proposed optimal production strategy for a Class 2 deposit and the three phases of production. Phase 1: Initial production stages. Phase 2: Early intermediate production. Phase 3: Late stages of production (illustration modified from Moridis et al., 2008).

5.4.3 Class 3 Deposit

The optimal strategy is much less clear for Class 3 deposits than for Class 1 and 2 deposits. The lack of a relatively permeable layer underneath the HBL from which fluids can be removed, such as in Class 1 and 2, means that inducing dissociation of the GH interface is difficult. The alternative, if opting for a depressurization strategy, would be to complete the well into and directly depressurize the HBL, though gas production would be slow to build up due to the low permeability of the HBL (unless the GH saturation is moderate to low) and a lack of a heat source to provide the energy needed for the endothermic dissociation reaction. Pure thermal injection and inhibitor injection is for large-scale commercial gas production from Class 3 deposits is not recommended in view of the reasons discussed for the gas production strategies for Class 2 deposits (Moridis et al., 2008). In conclusion, although much less clear than for Class 1 and Class 2 deposits, depressurization with supportive thermal injection is recommended as the production strategy for Class 3 deposits.

5.5 Recommended Production Strategies

For GH reservoirs of Class 1, 2 and 3, the recommended production method is depressurization in conjunction with thermal stimulation in the near wellbore area to prevent the formation of secondary solids (ice and/or GHs) that would significantly reduce the permeability and consequentially the gas production rate (choking the well). This conclusion was significantly clearer for Class 1 and Class 2 deposits than for Class 3 deposits since the latter lacks an underlying mobile fluid layer to produce from, in order to achieve a rapid pressure reduction and for the pressure wave propagation to travel along the lower GH interface (the interface between the HBL and the underburden). However, the depressurization method was still considered to be superior for the Class 3 deposits compared to the alternative production methods, despite the reduced effectiveness of the method compared to Class 1 and Class 2 deposits.

6 Discussion

GHs are found in two distinct geographic regions: polar (1% of the resource) and deep oceanic (99% of the resource). When they are removed from the P&T conditions in which they are stable, they start to dissociate in an endothermic process to release free gas and water. The volume of the released gas depends upon the gas composition. The resulting free gas volume after dissociation of GHs is often assumed to be equal to the dissociation volume of pure methane GHs, because methane is the major component in naturally occurring GHs. Dissociation of 1 m³ of methane GH yields 164 Nm³ of free methane gas and 0.8 m³ of water. If the released gas is burned, and no losses to the environment are taken into consideration, the energy generated will be 16.35 times higher than the energy required to dissociate the same volume.

The considerable gas release that occurs during dissociation can cause a significant volume expansion in confined spaces, for instance in the wellbore, which consequentially leads to the gas displacing a corresponding volume of mud. Such a situation can quickly develop into a well control situation that in the worst case can lead to a blow out. Drilling techniques that are unable to prevent the dissociation of GHs in the wellbore and/or handle the produced gas volumes when GHs dissociate, are not suited for drilling through hydrate formations. UBD is an example of the former, as it keeps the BHP below the reservoir pressure. OBD is a drilling technique that is an example of the latter, and that in addition will cause invasive formation damage when drilling through GH reservoirs. The optimal drilling technique, which is MPD, is able to control the pressure throughout the wellbore during drilling and to quickly react to pressure changes by applying backpressure at the surface. In addition to controlling the pressure in the wellbore, it is also important to control the temperature to ensure that the GHs stay within the stability envelope of the GHs. Utilizing surface mud cooling and insulation methods, or changing the circulation rate achieves this. The effect of surface mud cooling is fairly easy to install, has a low cost of implementation, and is very effective in reducing the wellbore temperature. Insulation methods can be fairly effective, although it is generally considerably more costly and difficult to implement. Insulation methods should be considered used for production purposes or in combination with surface mud cooling to have the greatest effect. A high circulation rate will reduce the wellbore temperature, although it will also increase the pump requirements and borehole erosion.

Depressurization is a technically simple, efficient and low cost production method that is very effective on Class 1 and Class 2, and fairly effective on Class 3 GH reservoirs. Thermal stimulation and inhibitor injection are inefficient, costly and ineffective methods. The first one requires a large amount of heat, while the second one has a rapidly reducing efficiency in the reservoir, requires large volumes of costly chemicals that are difficult to reuse, and contaminates the produced gas. CO₂ injections is a fairly new and unproven technology that requires technological advances and further R&D before it can be utilized to achieve commercial gas production for GH reservoirs.

7 Conclusion

7.1 Gas Hydrates

- GHs that are removed from stable P&T conditions become unstable and start to dissociate through an endothermic process that yields a large volume expansion.
- Dissociation of 1 m³ of GH, that is assumed to be composed entirely of methane, yields 164 Nm³ of free methane gas and 0.8 m³ of free water.
- Without taking into account losses to the environment, the energy required to dissociate 1 m³ of GH is 6.12% of the energy that is obtained from burning the released gas.
- The volume estimates of gas frozen in GHs worldwide remain highly uncertain, although a reasonable figure has been suggested to be 20·10⁵ Nm³.
- Although the ERR and TRR is low for GH resources, it is expected to increase over time.
- The two challenges that must be overcome before commercial gas production can be achieved from GH resources are: identification of promising resources, and the undertaking of studies which show that the gas production rate and cumulative gas production for such promising resources is economical.

7.2 Drilling

- Dissociation of GHs in the wellbore must be avoided to reduce the likelihood and consequences of a well control incident and other drilling-related challenges.
- Reformation in the wellbore and important well control equipment can be reduced or avoided by adding thermodynamic inhibitors and kinetic inhibitors/anti-agglomerates in the mud.
- Dissociation of GHs in the wellbore can be limited or avoided by maintaining the wellbore temperature within the stability conditions of the GHs.
- MPD is the recommended optimal drilling technique based on its ability to precisely control the pressure of the entire wellbore during drilling and is able to react quickly to pressure changes by applying backpressure at the surface.

- The temperature in the wellbore can be controlled by surface mud cooling, insulation methods or changing the circulation rate.
- Surface mud cooling on its own can be used to lower the inlet temperature of specialized freeze-depressed muds down to between -3°C and 0°C , even when drilling surface- and intermediate hole sections.
- CwD can be used along with MPD to reduce the probability and consequences of wellbore instability and other drilling-related challenges.
- Low exothermic cement should be used when cementing casings to prevent GH dissociation behind the casing.
- The optimal solution to drill production wells in hydrate formations is to combine MPD with CwD, surface mud cooling, insulation, thermodynamic inhibitors and kinetic inhibitors/anti-agglomerates, low exothermic cement during cementation and a relatively high circulation rate.
- The equipment, methods and drilling techniques discussed in this thesis are all existing and proven technology, and it is proposed that these and other existing technologies can be used together to drill production wells in GH reservoirs safely, effectively and economically.

7.3 Matlab

- Modifications were made to the base Matlab model to enable the simulation of the annulus temperature distribution during drilling into a HBL, and improvements were made regarding the initial formation temperature, initial drill pipe temperature and the initial annulus temperature.
- The simulation itself was unfortunately unsuccessful, due to issues with implementing the model in matlab (creating the code).
- The modified Matlab program for the annulus temperature distribution during drilling into a HBL is included in Appendix B – Matlab Program. Suggestions for further work is included in section 4.8.

7.4 Production

- The four main methods to produce gas from GH reservoirs are: depressurization, thermal stimulation, inhibitor injection and CO₂ injection. They act by destabilizing the GHs in the reservoirs, causing them to dissociate.
- GH reservoirs can be classified as either Class 1, Class 2 or Class 3 deposits. The recommended production strategy for all three classes is depressurization in conjunction with thermal stimulation in the near wellbore area to prevent the formation of ice and secondary GHs.

8 Nomenclature

Abbreviation	Description
BHA	Bottom hole assembly
BHL	Hydrate bearing layer
BHP	Bottomhole pressure
BOP	Blowout preventer
CwD	Casing while drilling
DEG	Diethylene glycol
ECD	Equivalent circulating density
ERR	Economically-recoverable resource
GH	Gas hydrate
GHSZ	Gas hydrate stability zone
GIP	Gas-in-place
HBS	Hydrate bearing sediment
ID	Inner diameter
MEG	Monoethylene glycol
MPD	Managed pressure drilling
Nm ³	Normal cubic meters (0°C, 1 bar)
NPT	Non-productive time
OBD	Overbalanced drilling
OD	Outer diameter
P&T	Pressure and temperature
R&D	Research and development
RR	Recoverability ratio
STP	Standard P&T conditions (0°C and 1 bar)
TD	Target depth
TEG	Triethylene glycol
TRR	Technically-recoverable resource
TVD	True vertical depth
UBD	Underbalanced drilling

Parameters	Description
k_h	Thermal conductivity
M_{bit}	Drill bit torque
M_s	Volumetric heat capacity of the formation
r_p	Radius of the drill pipe
r_w	Radius of the wellbore
U_{pipe}	Heat transfer coefficient
w_c	Unit contact force
μ_f	Coefficient of friction
ΔT	Temperature difference
A	Surface area
C_p	Heat capacity
Depth	Total depth of the well
G	Guest gas in the GH
g	Gravitational constant
Geothermal gradient	Formation temperature increase with depth
h	Height of or depth in the fluid column
m	Mass
M_G	Molar mass of the GH guest gas
M_W	Molar mass of water
n	Number of moles of gas
N	Drill pipe rotations per second
N_H	Hydration number
P	Pressure
Q	Heat transferred/generated
q	Fluid flow rate/circulation rate
R	Gas constant
ROP	Rate of penetration
T	Temperature (in Kelvin or Celsius)
t	Time
V	Volume
V	Volume
v	Velocity

WOB	Weight on bit
Z	Current depth, measured from surface
α	Thermal diffusivity of the formation
β	Bit efficiency
Δ	Difference
ρ	Density
φ	Porosity

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Appendix A – Energy Ratio of Gas Dissociation

Energy required to dissociate 1 m³ of methane GH ($n_H = 6$):

$$M_{GH} = M_G + M_W n_h = 16.04 \frac{g}{mol} + 18 \frac{g}{mol} \cdot 6 = 124.04 \text{ g/mol}$$

$$\Delta h^\circ_{diss_{GH}} = 54.19 \frac{kJ}{mol}$$

$$\Delta h^\circ_{diss_{GH}} = \frac{54.19 \frac{kJ}{mol}}{124.04 \frac{g}{mol}} = 0.437 \frac{kJ}{g} = 437 \frac{kJ}{kg}$$

$$\Delta h^\circ_{diss \text{ per } m^3 \text{ of } GH} = \Delta h^\circ_{diss_{GH}} \cdot \rho_{GH} = 437 \frac{kJ}{kg} \cdot 900 \frac{kg}{m^3} = 393.3 \text{ MJ/m}^3_{GH}$$

Energy content of methane gas in 1 m³ of methane GH (164 N m³):

$$PV = nRT$$

$$n = \frac{PV}{RT} = \frac{100,000 [Pa] \cdot 1 [m^3]}{8.314 [\frac{J}{K \cdot mol}] \cdot 273.15^\circ K} = 44.03 \text{ mol}$$

Energy content of 1 Nm³ of methane gas

= Heat of combustion per mole · Number of moles

$$= 891 \frac{kJ}{mol} \cdot 44.03 \frac{mol}{Nm^3} \approx 39,231 \frac{kJ}{Nm^3} \approx 39.2 \frac{MJ}{Nm^3}$$

Energy content of methane gas contained in 1 m³ of methane GH (164 Nm³)

$$= 39.2 \frac{MJ}{Nm^3} \cdot 164 \text{ Nm}^3 / m^3_{GH} \approx 6.43 \text{ GJ/m}^3_{GH}$$

Ratio of energy gained:

$$\begin{aligned} \text{Ratio of energy gained} &= \frac{\text{Energy content of methane gas in 1 m}^3 \text{ of methane GH}}{\text{Energy required to dissociate 1 m}^3 \text{ of methane GH}} \\ &= \frac{6.43 \text{ GJ/m}^3_{GH}}{393.3 \text{ MJ/m}^3_{GH}} \approx 16.35 \end{aligned}$$

Appendix B – Matlab Program

The Matlab function shown below is developed to calculate the annulus temperature in the wellbore as a function time while drilling at a specific depth. The output data is the annulus temperature distribution. As a consequence of difficulties with programming the developed Matlab model, the simulation does not yield correct results.

```
function annuls_temperature_while_drilling

%Model assumptions
  %-Vertical well
  %-Drilling and circulating at a fixed depth (which is the
target_depth)
  %-Constant formation temperature
  %-Pressure drop in annulus is a fixed value per segment length
  %-Pressure drop in drillpipe is a fixed value per segment length

%-----%Initial values and variables-----
---

target_depth=1200; %vertical depth of the well [m]
T_mud_inlet=0; %The temperature of the mud when entering the drillpipe
at surface [Celsius]
circulation_number=4;

geothermal_gradient=20; %geothermal gradient below the surface,
temperature increase in celsius per kilometer [C/m]
T_surface=0; %temperature at the seabed/surface [degrees C]
numeric_segment_height=1;%The hight of the numeric segments used in
the calculation [m]
q_circulation=2000/(1000*60); %Circulation rate converted from lpm
(liters per minut [m^3/s]
D_hole=17.5*0.0254; %17 1/2 inch borehole/bit size [m]
OD_DP=6.625*0.0254; %6 5/8 inch outer diameter drillpipe [m]
ID_DP=6.167*0.0254; %6 1/6 inch inner diameter drillpipe [m]
rho_mud=1100; %Density of the drilling fluid [kg/m^3]
Cp_mud=4210; %Heat capacity of the drilling fluid [J/kg-K]
U_pipe=0.02; %The heat transfer coefficient (assumed to be constant
throughout the drillpipe) [kW/m^2-K]
Delta_P_DP_per_meter=0.04*10^5; %Pressure loss inside the drillpipe in
one hight segment per meter [Pa/m]
Delta_P_annulus_per_meter=0.02*10^5; %Pressure loss inside the
annulus in one hight segment per meter [Pa/m]
A_nozzles=6.8*10^(-4);
K_h=0.0017; %thermal conductivity [kW/m*c]
M_s=2673; %volumetric heat capacity of the formation [kJ/m3*C]
alpha=K_h/M_s; %thermal diffusivity of the formation [m2/s]
WOB=2000*9.81; %The weight on bit [kg]
M_bit=4000; %The drill bit torque [N*m]
RPS=2.5; %The number of times the drillpipe rotates pr minute [s^(-1)]
ROP=2/3600; %Rate of penetration [m/s] (calculated from m/hr)
bit_efficiency=0.7; %[Dimensionless]
```

```

T_DP=zeros(target_depth,circulation_number);
T_annulus=zeros(target_depth,circulation_number);

%-----%Initial calculations-----

%Pressure drop over the bit (Skalle, 2012 - Drilling fluid
engineering)
Delta_P_bit=1.1*0.5*rho_mud*((q_circulation/A_nozzles)^2); %Pressure
over the bit in one height segment [Pa]
%The time the fluid spends in each height segment inside the drillpipe
is given by t=V/Q [s]
t_pipe_numeric=(pi()/4*ID_DP^2*numeric_segment_height)/q_circulation;
%The time the fluid spends in each height segment inside the annulus
is given by t=V/Q [s]
t_annulus_numeric=(pi()/4*(D_hole^2-
OD_DP^2)*numeric_segment_height)/q_circulation;
%The surface area where the heat transfer occurs between the inside of
the
%drillpipe and the annulus (inside pipe diameter is the one used)
A_DP_inside_heat_transfer=2*pi()*ID_DP/2*numeric_segment_height;
%The surface area where the heat transfer occurs between the formation
and
%the annulus [m^2]
A_annulus_heat_transfer=2*pi()*D_hole/2*numeric_segment_height;
%Volume of one height segment of the drillpipe [m^3]
V_pipe_numeric=(pi()/4*ID_DP^2)*numeric_segment_height;
%Volume of one height segment of the annulus [m^3]
V_annulus_numeric=pi()/4*(D_hole^2-OD_DP^2)*numeric_segment_height;
%Work done by the bit [W]
Q_bit=(1-bit_efficiency)*(WOB*ROP+2*pi()*RPS*M_bit);
%Temperature increase at the bit due to work done by the bit [Celsius]
Delta_T_bit=Q_bit*t_annulus_numeric/(V_annulus_numeric*rho_mud*Cp_mud)
;
%Temperature increase at the bit due to heat generated by pressure
loss over the bit
Delta_T_bit_loss=Delta_P_bit/(rho_mud*Cp_mud);
%Temperature increase in the drillpipe due to pressure loss in the
drillpipe
Delta_T_DP_loss_per_segment=Delta_P_DP_per_meter*numeric_segment_heigh
t/(rho_mud*Cp_mud);
%Temperature increase in the annulus due to pressure loss in the
annulus
Delta_T_annulus_loss_per_segment=Delta_P_annulus_per_meter*numeric_seg
ment_height/(rho_mud*Cp_mud);
%drillpipe_circulation_number=ceil(t_drilling_each_numerical_segment/t
_pipe_numeric);
%annulus_circulation_number=ceil(t_drilling_each_numerical_segment/t_a
nnulus_numeric);

%-----%Assigning initial values to all numerical segments in
drillpipe, annulus and formation-----

%Assigning initial values to the temperature of the drillpipe, annulus
and formation based on the
%initial formation temperature at each depth, divided into the height
of the numerical segment
%sections, and of the initial drillpipe and annulus temperature
ignoring
%heat transfer between the drillpipe and the annulus, and the annulus

```



```

and
%the formation, but taking into account pressure loss in the
circulation system and heat generated by
%the drillbit. t=1 is the initial condition.
for z=1:numeric_segment_height:target_depth

    %Assigning initial values of formation temperature, which is
    assumed constant at each depth, and only dependent upon the depth
    T_formation(z,1)=T_surface+geothermal_gradient*(z/1000);
    %[Celsius]

    %Assigning initial values of drillpipe temperature [Celsius]
    if z==1
        T_DP(z,1)=T_mud_inlet; %Inlet mud temperature in the drillpipe is
        constant due to mud cooling at the surface
    elseif z>1
        T_DP(z,1)=T_DP(z-1,1)+Delta_T_DP_loss_per_segment;
    end

    %Assigning initial values of annulus temperature [Celsius]
    if z<target_depth
        T_annulus(z,1)=T_DP(z,1)+Delta_P_DP_per_meter*(target_depth-
        z)/(rho_mud*Cp_mud)+Delta_T_bit+Delta_T_bit_loss+Delta_P_annulus_per_m
        eter*(target_depth-z)/(rho_mud*Cp_mud);
    elseif z==target_depth
        T_annulus(z,1)=T_DP(z,1)+Delta_T_bit+Delta_T_bit_loss+Delta_T_annulus_
        loss_per_segment;
    end
end

%!!!These 3 are all correct and make sence!!!
T_DP_initial=T_DP
T_annulus_initial=T_annulus
T_formation_initial=T_formation

%Plot of initial temperature of formation, annulus and drillpipe
y=1:target_depth;
plot(T_formation_initial,y,T_DP_initial,y,T_annulus_initial,y)
set(gca,'YDir','reverse')
legend('T formation','T drillpipe','T annulus')

%y=1:target_depth;
%plot(T_formation_initial,y)
%set(gca,'YDir','reverse')
%legend('T formation')

%-----%Simulation, including heat transfer between formation,
annulus and drillpipe-----

for t=2:(circulation_number+1)
    for z=1:numeric_segment_height:target_depth

        %Heat transfer from the annulus to the inside of the drillpipe
        [kJ]
    end
end

```

```

Q_annulus_pipe(z,t)=U_pipe*A_DP_inside_heat_transfer*(T_annulus(z,t-1)-T_DP(z,t-1))*t_pipe_numeric;

    %Heat transfer from the formation to the annulus [kJ]

Q_formation_annulus(z,t)=K_h*A_annulus_heat_transfer*(T_formation(z,1)-T_annulus(z,t-1))/(D_hole/2)*((2*pi()*alpha/(D_hole/2)^2)^(-0.5)*t_annulus_numeric^0.5+0.5*t_annulus_numeric-(1/6)*(alpha/(((D_hole/2)^2)*pi()))^0.5*t_annulus_numeric^1.5+(1/16)*alpha*t_annulus_numeric^2/(D_hole/2)^2);

end

    %Calculating values for the temperature in the drillpipe from z=1 to z=target depth
    for z=1:numeric_segment_height:(target_depth-1)

        if z==1
            T_DP(1,t)=T_mud_inlet;

T_DP(2,t)=T_mud_inlet+(Q_annulus_pipe(z,t)*1000)/(V_pipe_numeric*rho_mud*Cp_mud)+Delta_T_DP_loss_per_segment; %Inlet mud temperature in the drillpipe at the surface is constant (mud cooling)
        elseif z>1
            %Temperature inside the drillpipe, heated by heat flowing from the annulus and pressure loss inside the drillpipe [Celsius]

T_DP(z+1,t)=T_DP(z,t)+(Q_annulus_pipe(z,t)*1000)/(V_pipe_numeric*rho_mud*Cp_mud)+Delta_T_DP_loss_per_segment;
        end

    end

    %Calculating values for the temperature in the annulus from z=1 to z=target depth
    for z=1:numeric_segment_height:target_depth

        z=(target_depth+1)-z;

        if z==target_depth

T_annulus(target_depth,t)=T_DP(target_depth,t)+Delta_T_bit+Delta_T_bit_loss+Delta_T_annulus_loss_per_segment+(-Q_annulus_pipe(z,t)*1000+Q_formation_annulus(z,t)*1000)/(V_annulus_numeric*rho_mud*Cp_mud);
            elseif z<target_depth
                %Temperature inside annulus, heat lost to the drillpipe, and heat gained from the formation and pressure loss in the annulus [Celsius]

T_annulus(z,t)=T_annulus(z+1,t)+(-Q_annulus_pipe(z,t)*1000+Q_formation_annulus(z,t)*1000)/(V_annulus_numeric*rho_mud*Cp_mud)+Delta_T_annulus_loss_per_segment;
            end

        end

    end

t_pipe_numeric;
t_annulus_numeric;
Delta_T_bit;

```

```
Delta_T_DP_loss_per_segment;  
Delta_T_bit_loss;  
Delta_T_annulus_loss_per_segment;
```

```
%Q_annulus_pipe  
%Q_formation_annulus  
T_DP  
T_annulus  
%T_formation
```

```
t_pipe_numeric;  
t_annulus_numeric;  
A_DP_inside_heat_transfer;
```

```
end
```