Universitetet
i Stavanger

Faculty of Science and Technology

MASTER'S THESIS

Study program / Specialization: **Industrial Economics** **- Project Management**	Spring semester, 2016 Open access
Writer: **Aina Undersrud Bratland**	………………………………………… (Writer's signature)
Faculty supervisor: **Terje Martin Halmø** External supervisor: **Anders Soltvedt, Norwegian Petroleum Directorate**	
Thesis title: **Depressurization of Oil Fields with Gas Injection** **– Decision Criteria, Timing and Value Creation**	
Credits (ECTS): 30	
Key words: Depressurization, Norwegian Continental Shelf, Decision Criteria, Timing, Value Creation, Real Options Valuation	Pages: 57 Stavanger, 15th of June, 2016

Preface

This thesis is a final assignment for my master's degree in Industrial Economics, built on a bachelor's degree in Petroleum Technology.

There is a strong focus on prudent production of oil and gas on the Norwegian Continental Shelf (NCS). At the same time, it becomes even more important to come up with profitable and smart technical solutions in a tough competitive market. This motivated me to combine my knowledge within petroleum technology and economics.

I want to thank all the people who have supported me throughout the semester and contributed with their knowledge. First, I want to express my great appreciation to my faculty supervisor, Terje M. Halmø. His valuable experience from the industry as well as academic knowledge have been very helpful during the whole process of thesis writing. A great gratitude also goes to my external supervisor, Anders Soltvedt, who has facilitated for the contact with Statoil, provided updated information on the NCS and encouraged me throughout the semester.

A great appreciation also goes to Hallstein M. Ånes and Dag Frafjord from Statoil, who have been incredibly helpful and shared important experiences from industry practices.

I will like to offer my special thanks to Reidar Bratvold, for his engagement in my work. He has contributed with important topics for discussion, and put me in contact with key persons in order to conduct a real options valuation. Assistance provided by Philip Thomas, a PhD student of UiS, is also greatly appreciated. He helped me set up the model in the Matlab Software, and supported me during the analysis. Yichen Yang, a master's student within Petroleum Geoscience, also deserves a great thanks for helping me create oil and gas production profiles.

Abstract

The common approach for oil fields with gas injection is to continue oil production and re-inject the gas produced for as long as it is profitable, and then shift to gas production. However, the value of the gas as well as the option value of gas sales versus injection is important to consider. Stopping gas injection or withdrawal of large volumes of oil/gas will for instance result in a rapid pressure loss, which benefits a shift from oil to gas production. This depressurization process is often referred to as “blowdown” (BD).

The analysis conducted is divided into a qualitative and quantitative part. The qualitative analysis is based on interviews with Statoil focusing on reservoir properties, Increased Oil Recovery (IOR), technical challenges, gas export possibilities and decision criteria concerning BD for both the Statfjord and Oseberg field. As part of the quantitative analysis, a Real Options (RO) valuation was implemented to the purpose of determining the optimum decision from a set of possible BD scenarios for an example field. This included the following uncertain factors: future oil and gas prices, reservoir behavior and production profiles as well as relevant costs.

Based on the interviews, the reservoir condition was found to be the determinative factor for the decision criteria concerning BD. Representatives from Statoil indicated that the following were the overall decisive decision criteria for fields located on the NCS: The Petroleum Law §4.1 and economic evaluations. However, BD evaluations are complex and it might be challenging for the operators to interpret the petroleum legislation. Hence, the qualitative analysis indicated a lack of clarity in the decision criteria concerning BD for operators on the NCS. On one side, the operators and authorities are served with a great flexibility, however limited guidelines may result in inconsistent decision-making. Further technical aspects and possible value creation related to any BD project were evaluated.

The result of the RO valuation shows how varying different input-parameters affect the expected project value including BD and abandonment options. During the sensitivity analysis, both the highest expected value with options and the highest RO value was obtained when changing the variable cost of oil. This parameter was also found as the only one that significantly affected the BD decision.

Table of Content

1 INTRODUCTION

Firstly, the background for the thesis is presented followed by a brief definition of the thesis.

1.1 Background for Thesis

Injection of natural gas for increased oil recovery (IOR) is a common practice on oil fields in Norway. The natural gas production from the NCS was in 2015 distributed as follows according to the Norwegian Petroleum Directorate (NPD, 2016):

- 3 % Flare and fuel
- 24 % Gas Injection
- 73 % Gas Export

37.5 Billion standard cubic meters (GSm^3) of natural gas was injected into the reservoirs for IOR purposes. This constitutes for approximately 16 % of the total petroleum production from the NCS in 2015 (Norwegian Petroleum, 2016).

Lately, the oil price has decreased more relative to the gas price, and it can be questioned if it is still beneficial to re-inject the gas instead of introducing it to the market. The value of the gas as well as the option value of gas sales versus injection is important to consider. Figure 1.1 illustrates the prices in dollar/barrel (bbl) for NBP gas and Brent oil including future predictions by Information Handling Services Cambridge Energy Research Associates (IHS CERA). The red and orange solid lines represent an oil company's license price assumptions for oil and gas respectively, whereas the red dotted circle marks the rapid decrease of the oil price relative to the gas price during 2014.

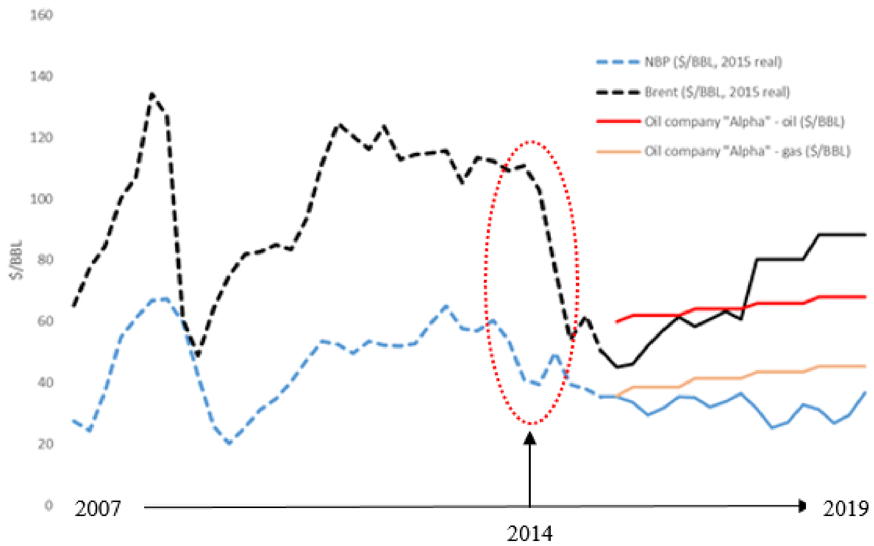

Figure 1.1: Prices for NBP Gas and Brent Oil including Future Predictions (NPD, 2016)

1.2 Definition of Thesis

The common approach for oil fields with gas injection is to continue oil production and re-inject the gas produced for as long as it is profitable, and then shift to gas production. The belief behind the approach is that maximizing oil production will maximize the value of the field, which is not necessarily the fact. In this thesis, depressurization of oil fields with gas injection including decision criteria, timing and value creation will be discussed.

As part of the literature study, experiences and common challenges associated with depressurization were studied, based on fields located in the U.K. and on the NCS. In order to get a reasonable understanding of the challenges and most important decision criteria, I chose to combine a qualitative and quantitative approach.

Interviews with key personnel from Statoil were conducted to identify the most commonly used decision criteria and associated uncertainties dependent on different field scenarios. Based on experiences through the literature study and interviews, an example field was created and simulated through a Real Options (RO) model using the Matlab Software. This in order to investigate the optimum blowdown (BD) time including sensitivity analysis associated with the decision.

The main goals were:

- Provide insight to the decision situation concerning BD including uncertainties related to timing and value creation.
- Illustrate how a RO model can be used to evaluate optimum timing for BD as well as determine how central input-parameters affect the decision.

2 THEORY

The purpose of this chapter is to provide the reader with relevant theory with respect to the thesis. Firstly, technical perspectives concerning natural gas, pressure support and gas-cap blowdown are presented, followed by market conditions in Europe and Norway.

2.1 Natural Gas and its Properties

Compared to other fossil fuels such as oil and coal, natural gas serve as a cleaner solution. While burning, it emits lower levels of harmful gases to the atmosphere. The global demand for energy is increasing, and the environmental aspects have become more and more central to our daily life. This has brought supply of natural gas to such a level of importance in the global society (Bezruchenko, 2015).

In 2015 the total production of oil equivalents (o.e.) on the Norwegian Continental Shelf (NCS) was 227.8 MSm^3. In comparison, this is approximately 14 % less than the record year of 2004, and 5 % higher than in 2014. Also, the gas production increased in 2015. It was sold 115 GSm^3 gas, which is the highest amount counted from the NCS throughout a year (Norwegian Petroleum, 2016). An important reason for this relates to the increased demand from Europe as well as higher capability for gas delivery from the NCS. Figure 2.1 illustrates historical and predicted future production of oil, condensate, natural gas liquids (NGL) and natural gas in the period 1975-2020. After year 2000, the oil production has declined significantly and flattened out from 2013. On the other hand, natural gas production has increased gradually from 1996.

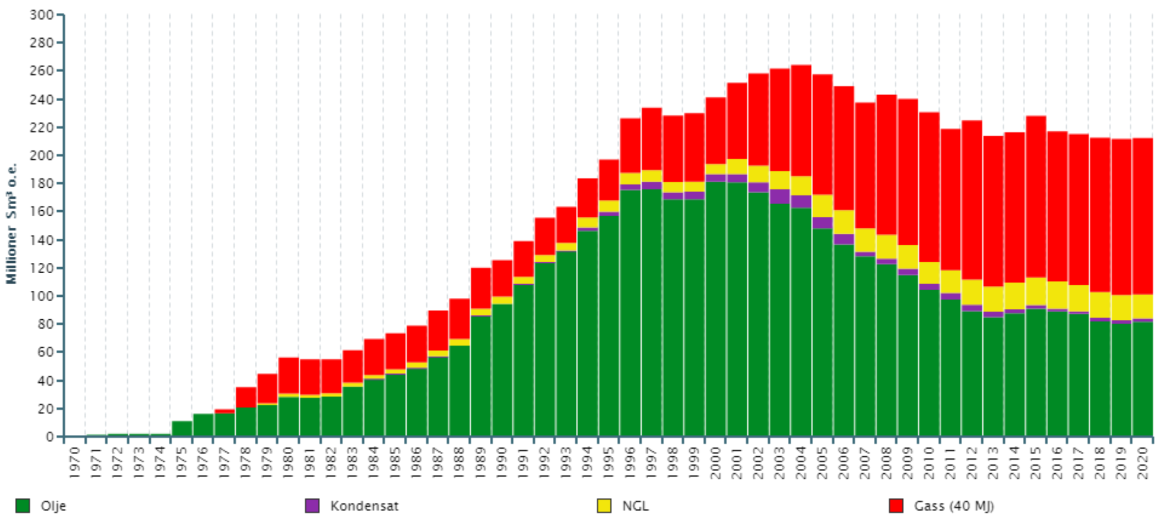

Figure 2.1: Historical and forecast of future production of Oil, Condensate, Natural Gas Liquids and Natural Gas in the period 1975-2020 (NPD, 2016)

2.1.1 Composition and Generation

Natural gas is often divided into two main categories: dry gas (mostly methane) and wet gas (such as ethane, propane and heavier components). Dry gas is often referred to as consumer-grade natural gas and can be sold without further processing. Natural gas may also contain small quantities of nitrogen, oxygen, carbon dioxide, sulfur components and water (Danesh, 1998).

Reservoirs of natural gas exist under the ground, trapped by impermeable rocks. When organic matter is compressed and exposed to very high pressures over a long period of time, hydrocarbons are made. This process will for instance create methane. Methane is also formed during transformation of organic matter by microorganisms. This process usually takes place close to the surface, and therefore produced methane is often lost to the atmosphere. Hydrogen-rich gases and carbon molecules located deep in Earth's crust also contribute to methane formation. Their interaction with minerals underground, in the absence of oxygen, may result in reactions creating compounds of presence in the atmosphere. Under very high pressures, they will likely form methane when migrating towards the surface (Natural Gas, 2013).

2.1.2 Production

Similar to oil, natural gas is produced through drilling activities both offshore and onshore. However, different production techniques are required due to geological characteristics. The industry often differentiate between non-associated and associated gas.

Non-associated gas is gas trapped in various rock formations. It is usually easy and feasible to produce. The gas enters the production line due to pressure differential between the reservoir and the well. Condensate production may also come together with the gas. Associated gas is produced as a byproduct of crude oil. When the well pressure is reduced, the gases are separated out of solution (Bezruchenko, 2015). When natural gas is brought to surface from the underground, it is refined in order to remove impurities such as water, sand, hydrogen sulfide and other compounds. This is done at both offshore and onshore facilities, dependent on the processing facility. After refining, the clean natural gas can be transmitted through pipelines to the consumers.

2.1.3 Products and Transportation

Methane is the main component of dry gas, which can be brought directly to the market without further processing. However, dry gas can also be converted to liquid at atmospheric pressure by cooling it down to -163 degrees Celsius. Natural gas liquids (NGL) such as pentane and heavier components are usually processed to liquefied products. It is important to differentiate between liquefied natural gas (LNG) and wet gas. Whereas LNG is dry gas converted to liquid condition by technology, wet gas is extracted directly from the depths of the Earth (Bezruchenko, 2015).

The following are the main transportation options for dry gas:

- *Transmission through pipelines*
- *Conversion to LNG*

Due to the difficulty of gas storage, the gas is preferably transmitted immediately to its destination. Transportation through pipelines is very convenient, but not flexible. The gas export pipelines usually has one arrival and one destination point, which means that the gas cannot be stored easily. Therefore, the production and receiving facilities need to shut down in periods, if problems with the pipeline occur. However, pipelines provide a long-term solution for transportation of gas.

The global gas market is gradually growing, and the geographic distance from the discoveries to profitable markets may result in physical or technical/economic challenges for the international gas pipeline network. The pipeline export capacity also gives a limitation of possible gas distribution and sale. Therefore, shipping of LNG serves as a good option. The liquefaction of dry gas reduces the volume of gas by approximately 600 times, given standard conditions such as temperature of 15 degrees Celsius and atmospheric pressure (Perez, 2009). LNG carriers provide a feasible solution for sale and transportation to profitable markets throughout the world. In figure 2.2, a comparison between transportation cost in pipelines and as LNG is illustrated. The green curve represents the cost for an LNG producer, whereas the red curve is added to the original figure to illustrate the cost of reload for any buyer of LNG. It can be seen that LNG serve as the most economical solution for longer transportation distances.

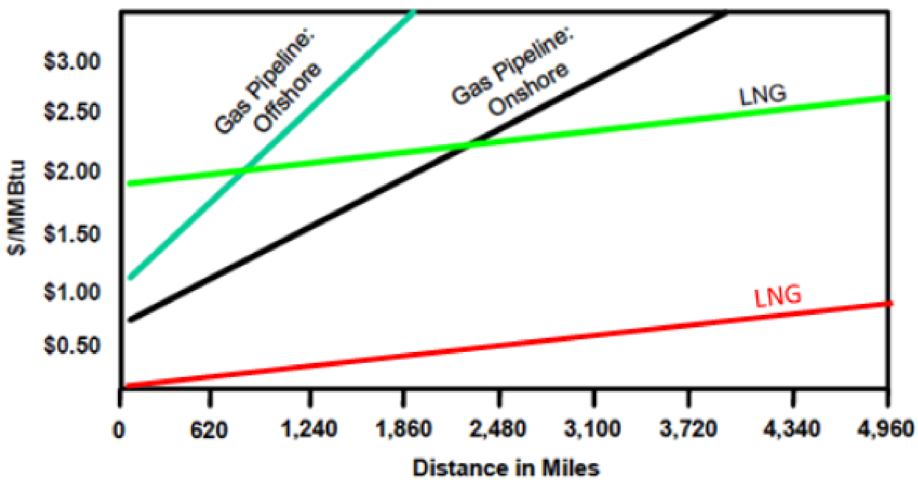

Figure 2.2: Comparison of transportation cost in pipelines and as LNG (Edgar, T.F., & Himmelblau, D.M in Perez, 2009)

2.2 Methods for Pressure Support

Reservoir drive mechanism provides pressure support through fluid displacement from the reservoir towards the wellbore. Dependent on the drive mechanism, different recovery rates can be expected. Natural drive mechanisms are usually present in any reservoir, in terms of a gas-cap, water drive or a combination. The water drive provides pressure support from the aquifer, as it expands slightly and displaces the oil from the reservoir towards the borehole. Free gas in a reservoir expands to replace produced hydrocarbons. This slows down the pressure decline rate and supports enhanced production. After some time the production profile as well as the reservoir pressure declines. Therefore, external pressure support might be necessary. Both gas and water are applicable fluids for external injection from surface to the reservoir (American Association of Petroleum Geologists (AAPG) Wiki, 2016).

2.2.1 Gas Injection

In the beginning of the oil industry development in Norway, there existed limited gas pipeline networks on the NCS for gas transportation. However, the Norwegian government introduced a ban on flaring, which is controlled burning of gas at production- or processing facilities. Therefore, the operators had to decide on whether to use the gas for re-injection for pressure support, or develop a pipeline network for gas sales. NPD (2009) has been a driving force for use of gas injection for IOR.

Ekofisk was the first field in Norway to make us of gas injection in 1987. The second was Statfjord, where a combination of water- and gas injection took place. This has resulted in an oil recovery factor of approximately 66 % for Statfjord. Oseberg was the first field, where gas injection was used as main recovery method for enhanced oil production. In addition to re-injecting its own gas, gas were imported from Troll, referred to as Troll Oseberg gas injection (TOGI). The recovery factor at Oseberg reached 63 %, whereas the average recovery factor on the NCS is 46 %. Since the gas production started on the NCS in 1971, more than 2000 GSm^3 has been produced. Most of it has been exported to the European market, but over 25 % has been re-injected to the reservoirs. So far, 28 fields on the NCS make use of gas injection (NPD, 2014).

Miscible and Non-miscible Gas Injection

When the injected gas enters the reservoir and connects with the oil, it can behave in various ways dependent on temperature and pressure. Either the gas will mix with the oil in a miscible solution, or it will separate from the oil into a non-miscible solution.

Miscible gas injection is characterized with a high extraction efficiency, and this method has been the main recovery method for Statfjord and parts of Åsgard. In a non-miscible solution, the gas settles over the oil layer, due to gravity. The gas expands and pushes the oil towards the lower pressure in the wellbore area. The biggest fields using this recovery method are Oseberg and Grane (NPD, 2014).

Carbon Dioxide and Nitrogen

In addition to natural gas, carbon dioxide (CO_2), nitrogen (N_2) and air are also applicable gases for injection. CO_2 has been used for a long period of time in USA, where there exist reservoirs with access to clean CO_2-gas. The method has not yet been implemented on the NCS, due to lack of CO_2 and high costs. However, the use of this method could result in an environmental benefit. Injection of N_2 and air are non-conventional methods, which still faces serious reservoir- and safety challenges (NPD, 2005).

2.2.2 Water Injection

Water injection is the most common method for IOR on the NCS. This method was successfully implemented at Ekofisk, after thorough investigations of applicability in the chalk formation. Easy access to the fluid makes this method very suitable. In some cases, it might be beneficial to use water instead of gas, as the gas can create value through sales in the market (NPD, 2005).

2.2.3 Alternating Water- and Gas Injection

Alternating water- and gas injection (WAG) is another method that has contributed to high recovery rates for many fields on the NCS. It combines the benefits of both water and gas injection. This often results in very low residual oil saturation, and the amount of gas required, can be limited, compared to ordinary gas injection. This method has enhanced recovery at fields such as Snorre, Gullfaks, Statfjord and Ula (NPD, 2014).

2.3 Gas-Cap Blowdown

Gas-Cap Blowdown (GCBD) describes the process where the gas-cap in the reservoir is depressurized. This process usually take place after oil plateau production when most of the oil reserves have been extracted. At a certain point, it might become profitable to shift from gas injection to gas production. It is also important to consider how a reduction in reservoir pressure will affect the pressures of surrounding fields (Reservoir Engineering Online, 2014).

Figure 2.3 illustrates the reservoir behavior from original fluid distribution in a) to start of GCBD in c). In b) one can observe the effect of gas injection, as the oil phase has been minimized due to production. While in c) the effect of depressurization is shown, as the gas is being produced and the aquifer pushes the waterfront upwards.

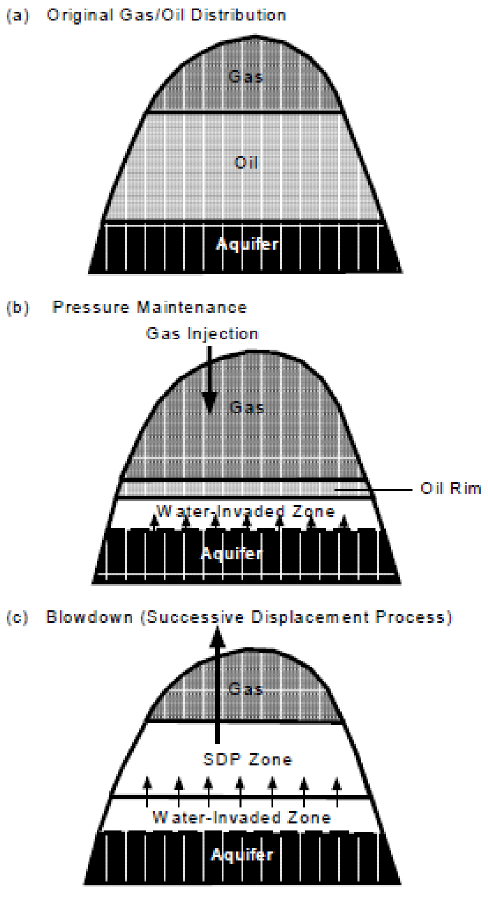

Figure 2.3: Reservoir Behavior during Gas-cap Blowdown (Beecroft, Mani, Wood, & Rusinek, 1999)

The GCBD process can be divided into the three following stages:

1. Stopping pressure maintenance through gas and water injection wells, while oil production continues.
2. The high Gas Oil Ratio (GOR) wells are opened. The GOR will gradually increase, and the oil wells will eventually turn into gas wells.
3. Shut down the watered out wells, as the waterfront continuously rises (Reservoir Engineering Online, 2014).

2.3.1 Production below Bubble Point Pressure

During production below bubble point pressure, gas will evaporate from the oil. Eventually the lightest components enter the gas phase, and the remaining oil will become more viscous (Matre & Helliesen, 1998). Reservoir depressurization can be achieved through withdrawal of large volumes of liquid or gas. This gives the opportunity of switching from mainly oil- to gas production, and possibly maximize value creation. In fields such as Statfjord, where there is no gas-cap, dedicated water producers are used to reduce the pressure. During the Statfjord Late Life (SFLL) project, the operators planned a yearly reduction in reservoir pressure of 30-40 bars (Boge, Lien, Gjesdal.A, & Hansen, 2005).

Typically, the Productivity Index (PI) decreases with 20-30 % because of increased oil viscosity, as the gas evaporates from the oil and enters the gas-cap. Crucial to every BD project is to maximize oil recovery as well as maintain profitable gas sales (Braithwaite & Schulte, 1992).

During depressurization, permanent damages to the reservoir and production facilities may occur due to various types of skin. Scale has already caused serious problems in the North Sea. When salt-solutions mixes with seawater or changes in temperature/pressure occur, permanent damages might take place as the absolute permeability is significantly reduced. Asphaltenes may also form when physical conditions are changed. When the pressure in the oil phase is reduced during gas production, the heavier components may precipitate and the lighter ones enter the gas-cap. This could result in permanent damage to the permeability and reduction in the productivity (Matre & Helliesen, 1998).

2.3.2 Technical Challenges during Depressurization

The main technical challenges associated with depressurization of oil fields are found to involve the following:

- *Critical Gas Saturation*
- *Aquifer Influx and Back-produced Water (BPW)*
- *Reservoir Compaction*
- *Sand Production*
- *Hydrogen Sulphide*
- *Well Engineering and Platform Design*

This knowledge is based on experiences from fields located on the Norwegian and British continental shelves such as Statfjord, Brent, South Brae and Miller. These fields have already been through a BD phase.

Critical Gas Saturation

"The critical gas saturation is the saturation at which gas first becomes mobile during a gas flood in a porous material that is initially saturated with oil and/or water" (SPE International, 2016). As an example, if the critical gas saturation is 4 %, the gas only flows when exceeding this value. It is important to understand gas mobilization in order to manage both oil and gas production. However, reservoirs with an existing gas-cap can start producing gas at once. Therefore, the critical gas saturation is more relevant to reservoirs with associated gas.

The critical gas saturation is strongly dependent on the pressure-decline rate in the reservoir. At the Brent field, water was back-produced in order to drag down the reservoir pressure to a sufficient level. Experiences from the Brent field indicated that the gas was expected to become mobile at lower reservoir pressures, and consequently required a lower pressure-decline rate. Therefore, the water production was reduced from 600-400 MStb/day (Shell, 1998) A Full Field simulation model (FFm) was used in order to determine the optimum amount of back-produced water (Ligthelm & G.C.A.M, 1997).

However, in cases with under-saturated oil such as the Miller field, more time is required to force the gas to become mobile. More risk is consequently associated with this type of reservoirs. Approximately 70% of the revenues from depressurization projects are related to gas production. Therefore, mobile gas should be established as soon as possible (Beecroft, Mani, Wood, & Rusinek, 1999).

Reservoir Compaction

Changes in the geological compaction and resulting subsidence could have a large impact on the production- and platform facilities in terms of safety margins. Investigations on the Brent field indicated a compaction value of 1 % of the gross reservoir thickness. Worst case assumptions predicted just below 2,5 %. However, field experiences showed that up to 5-6 % was acceptable. The Brent compaction study concluded that 1,6-2,4 m of subsidence could develop during the depressurization project. At the SFLL project, 1 m was expected after a pressure reduction of 250 bar. However, this can be monitored using technical devices such as a GPS (Global positioning system) (Braithwaite & Schulte, 1992). In general, there is a higher risk of subsidence in chalk-reservoirs such as Ekofisk, compared to sandstone reservoirs.

Sand Production

If the bottomhole pressure in a well is reduced below bubble point, the pressure gradient against the well will increase. That will further increase the potential of sand production. The effect of sand production and applicable actions should be considered prior to depressurization of any field (Matre & Helliesen, 1998). Based on laboratory studies and theoretical work, initial rock failure of average strength sand is expected at a reservoir pressure of approximately 207 bar. At constant pressure drawdown, sand production will stabilize and drop to manageable levels (Braithwaite & Schulte, 1992).

Hydrogen Sulphide

Hydrogen Sulphide (H_2S) forms when bacteria from water injection chemically react with nutrients in the formation water. The sulphate content in the injection water will "feed" the sulphate-reducing bacteria. These bacteria will reduce the sulphate from 6+ to 2- and form H_2S (Braithwaite & Schulte, 1992). In order to manage H_2S production, chemicals such as Traizine is injected to the separators breaking down the harmful gas (Shell, 1998). Investigations into the H_2S content at the Brent field indicated that substantial levels would only rise at the end of the pressure maintenance phase. It was predicted a higher than 50 % chance of average levels of H_2S exceeding the contract limit for dry gas of 3,3 ppm. However, only a 25 % probability of exceeding the FLAGS pipeline limit, which would require installation of an offshore treatment system, where predicted spare capacity on the platform should be available in case of additional facility installation due to offshore regulations. Currently, the H_2S content produced from the Brent formation is at low, but gradually increasing levels (Braithwaite & Schulte, 1992).

Platform Design and Well Engineering

When shifting from mainly oil to gas production, a major transformation of the platform facilities must be expected. Installation of processing facilities, low-pressure separators and gas compressors for export purposes are examples of project investments that might be necessary. Further, drilling of new wells might be required as well as converting oil production wells to gas producers.

2.3.3 Management and Risk

The total cost of the SFLL investment at Statfjord was 15 billion NOK. Approximately 30 % counted for well investments, 60 % for topside modifications and 10 % for the new gas export pipeline. In addition, it required 3 million man-hours during a period of 4-6 years. Not only the investment cost, but also the operational cost must be considered (Boge, Lien, Gjesdal.A, & Hansen, 2005).

However, great revenues are expected from depressurization projects. This can be explained by the increase in recovery factors for both oil and gas. Statfjord started production in 1979 and reached oil plateau production in 1985. Injection of water and gas stopped in 2007, as part of the SFLL project. It resulted in an increase of the gas recovery factor from 53 to 74 %, as well as an increase in the oil recovery factor from 65 to 68 %. The lifetime of the field was extended by 10 years (Boge, Lien, Gjesdal.A, & Hansen, 2005).

The Brent field was discovered in 1971, and initiated production in 1976. After 22 years in production, the gas recovery factor was increased from 55 to 80 %, and the oil recovery factor increased from 54 to 57 % (Braithwaite & Schulte, 1992) (Shell, 1998). The project extended the lifetime of the field with 5-10 years (Christiansen, 1997).

Management

Overall management of the depressurization project is crucial to success. A proper full field simulation model is required in order to make correct reservoir predictions. As an example, calibration points of the free gas-cap should be included. It is essential to model this correctly in order to manage the annual demand of gas export to the market. Scenario analysis should also be conducted, simulating major variables of a field development project and their effects on the net present value (Shell, 1998).

Projects are rarely developed according to plan from start to abandonment. Implementation of new information, shifting assumptions and change in plans are crucial parts of project management. The same applies for depressurization projects in order to optimize oil and gas recovery.

Risk

Risk studies associated with depressurization were conducted for the Miller field. According to the results illustrated in figure 2.4, the critical gas saturation was the most important parameter, in terms of impact and likelihood. Other important parameters were aquifer strength, oil below the oil-water contact, reservoir compaction and permeability reduction. OPEX variables such as H_2S content, corrosion and sand production also contributed to the risk involved. The expected consequences of subsidence is low relative to project economics, although it could result in a large disaster if reaching critical levels (Beecroft, Mani, Wood, & Rusinek, 1999).

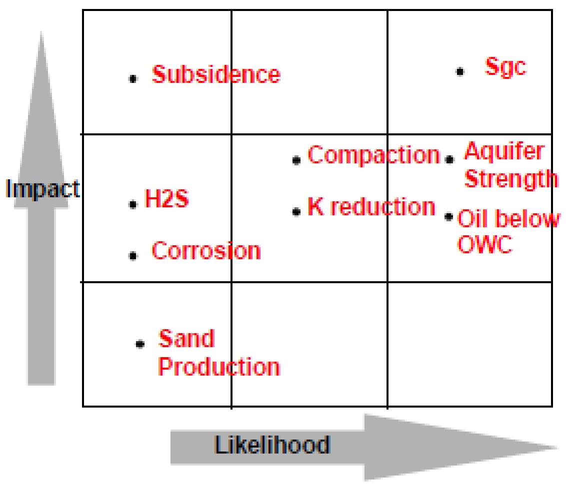

Figure 2.4: Result of Risk Studies on the Miller Field (Beecroft, Mani, Wood, & Rusinek, 1999)

The risk associated with a depressurization project is also very dependent on the future prices of oil and gas. Boge, Lien, Gjesdal.A, & Hansen (2005) indicate that the gas production rate is the most important variable parameter to consider, followed by oil production prognosis.

2.4 European Gas Hubs

Norwegian gas is dispatched to the European countries Germany, UK, Belgium and France. The following gas terminals receive Norwegian dry gas passed to downstream operators and end users:

- *St. Fergus and Easington in UK*
- *Dunkerque in France*
- *Zeebrugge in Belgium*
- *Emden and Dornum in Germany*

Figure 2.5 illustrates the pipeline network connecting the NCS with the receiving terminals in Europe.

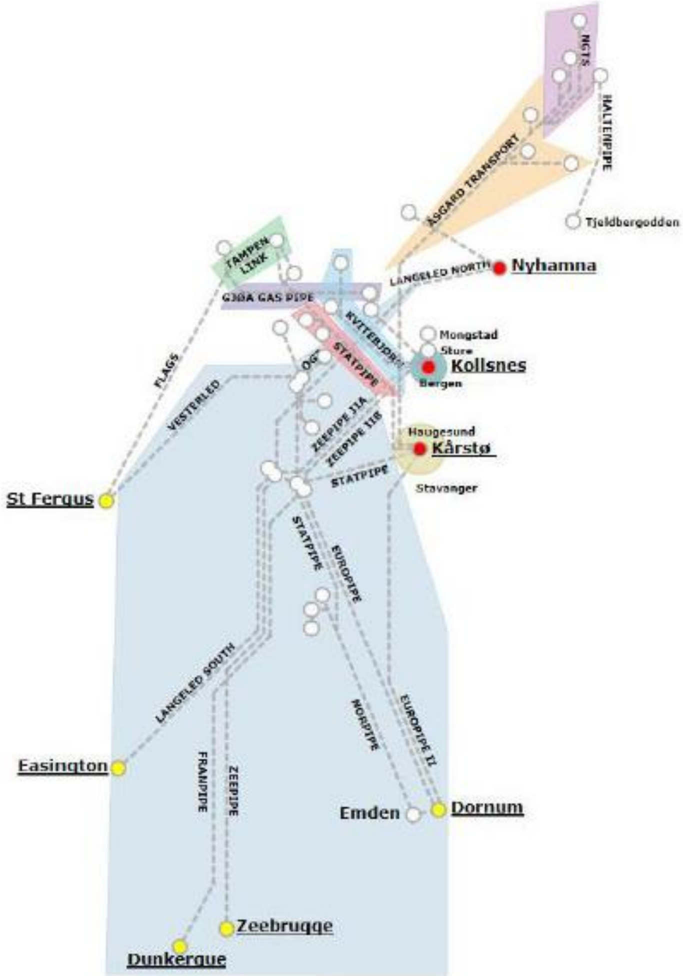

Figure 2.5: The pipeline network connecting the NCS with Europe (Stava, 2015)

Sales gas specifications such as hydrocarbon- and water dewpoint, CO_2- and H_2S content, Wobbe Index, Gross Calorific Value (GCV), maximum and minimum pressure and temperature must be satisfied prior to distribution (Heather, 2012).

2.4.1 Development of the European Gas Spot Market

The European gas industry is gradually growing in importance and liquidity. Previously large producing companies have dominated the market controlling the transportation network. However, third party access has lately contributed to increased competition. In the early 1990's upstream companies such as Total, Shell, Amerada, Hess, BP, Statoil and others controlled their gas production directly by establishing their own downstream companies. At that time commitments took place "over the telephone", as the bilateral market developed. In 1994-1995, the Heren Index, was established to systemize and present the agreed prices and volumes transacted during the day (Eclipse Energy Group, 2013).

In 1996, the Network Code was established to clarify and set out the rules for accessing and balancing the British pipeline grid. A system of daily balancing transactions, called the flexibility mechanism, was also introduced by the Network Code, where the transmission system operator was given acceptance to balance the system on a daily basis to ensure operation within safety standards. This was fundamental to the development of gas trading in the UK. In addition, the gas shippers were responsible for balancing their own deliveries and offtakes. If a shipper was out of balance, the system operator gave a penalty or forced them to buy/pay at the system marginal price (SMP). Either pay the highest price the system operator had to pay in order to balance the system, or sell at the lowest price on a given day. This system encouraged all parties to take responsibility in order to avoid penalties (Eclipse Energy Group, 2013).

In 1999, the On the Day Commodity (OCM) market replaced the flexibility mechanism, however keeping the balancing principles. The OCM, operated by the ICE Endex, provided anonymous clearing with zero risk for the counterparty. Today the National Balancing Point (NBP) is Europe's most liquid market for gas, functioning as a virtual point on the UK national transmission system. Originally, the Network Code created it to promote the balancing mechanism. However, NBP rapidly evolved as a busy trading point and become the preferred option among traders. Transactions quickly moved from the individual terminals to the NBP (Eclipse Energy Group, 2013).

In order to access the UK transmission system companies need to book entry capacity at one of the European receiving terminals. Shippers who want to bring physical gas delivery to one or several customers, also need to book exit capacity. For a long period, the British gas transmission development was isolated from the rest of the continent. However, introducing the interconnector pipeline between the Baction in the UK and Zeebrugge in Belgium contributed to spread the British experience over the continent. For the first time, in 1998, one could observe the connection between the British and continental European gas markets (Eclipse Energy Group, 2013).

UK and Netherlands have historically and are still considered as the leading gas trading nations. The markets in these two countries have also become mature since the churn has reached excess of 10. The term churn is " a measure of the number of times a parcel of a commodity is traded and re-traded between its initial sale by the producer and final purchase by the customer" (Heather, 2012).

Today NBP is functioning as the price setter for all the other European continental hubs, with exception of the Italian PSV. It is still growing in value and gradually attracting new participants (Heather, 2012).

2.5 Norwegian Gas Export Market

The amount natural gas delivered to Europe from Norway has never been higher. Currently Norway is the world's second largest gas exporter, supplying about 18% of Europe's need. In 2015 108 GSm^3 was transported from the NCS to the receiving terminals in Germany, Belgium, France and UK. This gives a gas export increase of 7 GSm^3 compared to 2014 (Gassco, 2016).

Previously, the owners of the Norwegian gas pipeline network were all the partners of the fields. However, in the period of 2000-2003, the gas sales from Norway was restructured. The individual ownerships of pipelines and processing plants merged to Gassled, which is a joint venture organized through committees and assignments. Gassco, a Norwegian state-owned company, was also established and assigned the role as the independent system operator (ISO) of the pipeline network. The main purpose of the company is to function as a neutral and independent operator of the integrated gas transport system from the NCS to continental Europe. The gas pipeline network connects all the major gas-producing fields on the NCS, adding up to a total length of 7975 km (Dahl, 2015).

Figure 2.6 illustrates the NCS gas pipeline network including the processing facilities Kollsnes, Kårstø, Nyhamna and Sleipner platform. The chart is divided into area A-I, whereas D is the dry gas area.

Figure 2.6: NCS gas pipeline network (Gassco, Bringing Norwegian Gas to Europe, 2015)

In Norway, gas trading is taking place bilaterally through negotiations. There has not yet been established an efficient marketplace to buy or sell gas. The gas is rather distributed to Europe, and linked to the market price at NBP. Sales are based on the net-back value, which means that the total revenue of the sales minus all costs associated with bringing the gas to the market are reflected (Eclipse Energy Group, 2013).

Area D connects directly to the receiving terminals through the pipeline grid to Europe and thus having access to a competitive market. The access and capacity through area D is a prerequisite in order to access the European market. Currently there is limited capacity available and in the period 2016-2018 the network area may be fully booked. Therefore, it might be considered too risky for newcomers to enter this area, as there is no guarantee of getting access to a competitive gas sales market (Eclipse Energy Group, 2013).

Eclipse Energy Group (2013) discusses the benefits of establishing a marketplace in Norway, which could facilitate pricing between licenses in Norway as well as providing easier access to gas-injection gas for IOR. It would also benefit the Norwegian industry and distributors to import gas directly from a market rather than rely on long-term bilateral contracts. This could also facilitate a larger upstream flexibility, delivering gas at several locations based on the highest price. The advantage of distributing gas sales within Norway is that the exit fee from Norway and the entry fee to European hubs are neglected. Thus, a Norwegian hub can trade at a discount compared to downstream hubs. Also "small scale LNG" companies would benefit from a potential establishment of a gas market, as it would provide access to the Gassled system at market prices ensuring competitive prices in line with European competitors.

2.6 Gas Pricing

Natural gas can be classified as a consumption asset, since it requires physical delivery in order to create value. Transportation often involves long distances and imposes substantial cost. As opposed to investment assets, which require zero transportation cost. The distribution of gas through pipelines may also cause delivery problems because of limited capacity.

The gas prices are related to physical delivery points, i.e. prices at NBP reflect physical delivery within the UK national gas grid. The gas from the NCS also reflects this market value, though the entry/exit fees due to transportation are subtracted. A challenge with natural gas supply is the limitation of storage. The gas should preferably be consumed right after production. The most significant reason to price volatility in the gas market is probably inelasticity in supply and demand. The demand for natural gas is closely related to weather, whereas production and infrastructure are the main drivers for limited supply (Bringedal, 2003).

Energy commodities are characterized by large volatility, however having a tendency of reverting back to long-term levels. This is a result of the gas supply being highly price responsive. As an example, when prices are high, gas consumers are looking for alternative energy sources. As opposed, when the gas prices are low, the demand and price will increase. Many large energy-consumers in the industry have this ability of changing energy source due to favorable prices (Bringedal, 2003).

2.6.1 Influencing Factors causing Gas Price volatility

Below are the most significant factors causing price volatility in the gas spot market presented:

- **Demand:** The last decade there has been a growing demand for natural gas in commercial and industrial sectors in Europe. In addition, environmental regulations and the desire for cleaner fuel have contributed to the increased trend of using natural gas to generate power.
- **Weather:** The demand for natural gas is strongly dependent on the season and weather. As the temperature drop, typically during winter, the demand for energy drives the natural gas spot price upwards. The opposite effect occurs during summer.

- **Natural gas storage:** Demand is typically lowest from March to November. During this period, there is a greater demand for underground natural gas storage providing a supply buffer.
- **Natural gas supply:** There is a large difference in short and long-term supply response if gas prices increase. In the short-run, increase in demand will cause prices to rise, and the operators are tempted to maximize production from the existing wells. However, a long-term increase in supply drives time-dependent activities such as new drilling programs, hiring, training and developing infrastructure.
- **Market psychology**: The market psychology can affect the above drivers in both the short and long-term. This factor is an interpretation by traders and analysts of events that may cause unexpected price levels. Such an impact should not be under estimated (Bringedal, 2003).

Gas sales at the NCS takes place through bilateral negotiations, as there is no standard agreements for gas sales at the NCS. It can be argued that prices determined by an anonymous liquid market is more efficient than bilaterally negotiations. In a liquid market there are several players competing on commodities, whilst bilateral negotiations only involve the seller and counterparty (Eclipse Energy Group, 2013). The operating market price on the NCS is based on the NBP market, subtracting entry- and exit fees. The buyers are exclusively license partners, as they have agreed on a field recovery strategy. Although gas sales are initiated by either individual companies or license partners (NPD, 2016).

At the NCS, gas-producing fields operates under the “linepack” principle. This provides Gassco with a certain flexibility, having the option of using the gas for pressurizing or loading the system in order to balance the gas pipelines (Eclipse Energy Group, 2013).

3 METHODOLOGY

In order to develop an understanding of the key challenges and most important decision criteria associated with the blowdown (BD) option, I chose to combine a qualitative and quantitative approach.

3.1 Qualitative Approach

There are a limited number of papers, books and reports where BD are discussed, and most only focus on the technical challenges. Therefore, I conducted interviews with key personnel from Statoil and had regular discussions with personnel at the NPD for the purpose of identifying the most commonly used decision criteria and associated uncertainties. The interviews with Statoil staff included both people with experiences from fields where the BD decision have already been initiated, such as Statfjord as well as teams evaluating possible future BDs, such as Oseberg.

3.2 Quantitative Approach

The BD decision is both complex and uncertain. Complex in that it includes a number of both technical and market related factors, and uncertain in that most, if not all, of these factors are uncertain. When facing decisions in complex and uncertain environments, it is useful to develop and evaluate models that can be used to remove confusion and attain insight, transparency and clarity around the important aspects of the decision. Although there are a number of uncertain factors that impact the BD decision, all are not equally important in the sense of being material to the decision. In order to be useful for the BD decision, the model should include the following uncertain factors:

- Future oil and gas prices
- Reservoir behavior and production profiles
- Relevant costs

The choice of model should be a function of the decision(s) the model is built to support. Bratvold & Thomas (2015) discuss how a Real Options (RO) valuation approach can be used to determine the optimum BD decision. This approach is also supported by Hem, Svendsen, Fleten, & Gunnerud (2011), who have used similar method in evaluating BD options. The philosophy of the approach is the following:

“*The gas is re-injected to maintain oil production only until the time it is more financially valuable to produce gas and thus blow-down pressure support for oil production”*
(Bratvold & Thomas, 2015)

The RO approach is dynamic and allows for future learning. The decisions are not made based on the decision-makers’ current (time=0) knowledge, but on future knowledge which comes from resolutions of uncertainties (price, production, etc.) over time. A more common, and perhaps more intuitive, approach to valuing the BD decision problem is the “naïve” approach where dynamic learning is not embedded in the model. In the naïve approach, the timing of the BD decision is made at time=0 with no room for change. It is determined based on scenario analysis, where the optimum BD time is found by sequentially evaluating all possible BD times. Although simpler to implement, the naïve approach is unrealistic as it assumes that the decision-makers do not respond and react to future information when they evaluate the BD decision. The RO approach is modeling both future learning and future decisions in a more realistic way. As discussed and demonstrated by Thomas & Bratvold (2015), it also results in near-optimum BD timing decisions with the result of increased value compared with the naïve approach.

The RO approach has been found as an applicable method for identifying and valuing the BD decision based on the goals of this thesis. As with all decision supporting models, the goal is not to estimate the correct economic value resulting from a decision, but to rank the alternatives based on the decision-makers’ decision criteria and thus provide the basis for high-quality decision-making. A material balance formulation has been used has been used in order to predict the future oil and gas production. More complex models, such as MBAL and Eclipse, can also be used with the RO model. However, as argued by Bratvold and Begg (2009):

“… the real problem in decision analysis is not making analysis complicated enough to be comprehensive, but rather keeping them simple enough to be affordable and useful.”

For the production model to be useful and affordable in the BD decision context, it must provide relevant insights to the decision-makers, which requires to depicts the future production and interdependencies of oil and gas.

Furthermore, uncertainty in cost as well as future oil and gas prices are taken into account. The RO problem is solved using Least Squares Monte Carlo simulation. Modelling of oil and gas prices is done using the Schwartz and Smith (2000) two-factor price process. This is a dynamic and probabilistic price model, which capture the market's view on the uncertain future prices and their fluctuations. Oil and gas prices are correlated based on market data. Both the price model and its calibration is described in detail by Bratvold & Thomas (2015).

4 ANALYSIS

The analysis chapter is divided into a qualitative part based on interviews with Statoil, and a quantitative part focusing on the optimum blowdown (BD) decision using a Real Options (RO) valuation model.

4.1 Interviews

Interviews were conducted with key personnel from Statoil representing the Statfjord and Oseberg field. The qualitative analysis summarizes key findings for both fields within reservoir properties and Increased Oil Recovery (IOR), technical challenges, gas export possibilities and decision criteria concerning the BD option.

4.1.1 Statfjord

Statfjord is a huge oil and gas field located at the U.K. – Norwegian boundary of the North Sea. The field is developed with three integrated platforms: Statfjord A, Statfjord B and Statfjord C, and comprises 580 km^2. Its production history is illustrated in figure 4.1, including net salable gas marked in red.

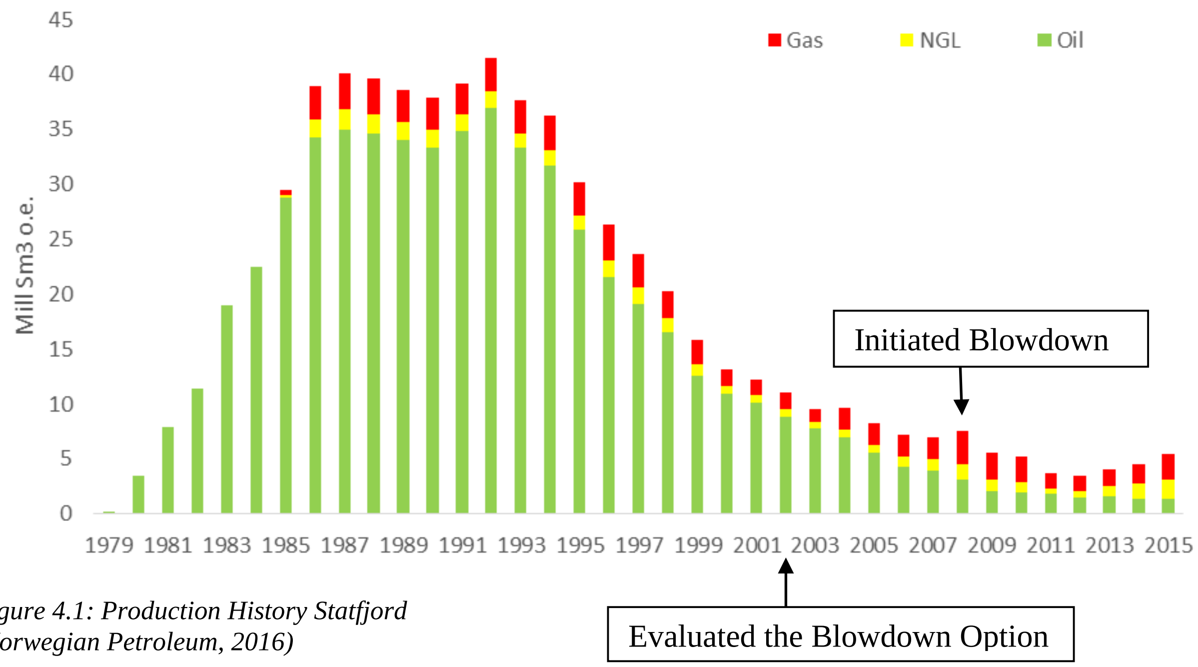

Figure 4.1: Production History Statfjord (Norwegian Petroleum, 2016)

In 2002, the BD option was discussed among the license partners for the first time. The BD was initiated in 2008, and is often referred to as the Statfjord Late life (SFLL) project. Because of the increased oil price and volume of produced oil, the project was delayed with one year. However, drilling of new wells in conjunction with the project started in 2005-2006. The field has produced much larger volumes of oil after initiating BD compared to what was expected. Today, the field is still being depressurized and the gas production is increasing. The lifetime of the field is estimated to 2020 for Statfjord A, and 2025 for Statfjord B and C.

Reservoir Properties and Increased Oil Recovery

The Statfjord field comprises production from both the Statfjord and Brent formation, with the Brent formation comprising up to 70 % of the reserves for the field. A thick shale layer divides the formations, and gas production takes place at both sides. Depressurization in both Brent and Statfjord has not affected each other much, however it has been proved that parts of the Tampen area are affected to some degree by Statfjord. Therefore, an area model was developed in order to better understand and predict the reservoir pressure variations in the Tampen area. Water injection has been the main method for maintaining the overall pressure in the field, however later replaced by WAG. Gas has basically been used for IOR purposes.

Technical Challenges

Based on information provided by Statoil, the main technical challenges associated with the BD phase were identified. The result is illustrated in figure 4.2, categorized with degree of likelihood on the y-axis and impact on the x-axis.

		Impact				
		Very Low	Low	Medium	High	Very High
Likelihood	Very High					
	High			Sand production	Critical Gas Saturation	
	Medium			Hydrogen Sulphide	Aquifer Breakthrough	
	Low			Subsidence		
	Very Low					

Figure 4.2: Risk Matrix Statfjord

Critical gas saturation is considered as the main challenge. There has been large uncertainty around this value, which possibly could delay the associated gas production with 1-2 years. Statfjord needed to produce large amounts of fluid from the Brent formation. This in order to depressurize the formation to liberate sufficient amounts of gas to generate moveable free gas. The pressure was reduced below the bubble point by back-producing water to reach the critical gas saturation. It took time, before the gas-accumulation was large enough to initiate gas production. The bubble point pressure is estimated to 270 bar, however an additional 70 bar reduction was required in order to firmly observe the effect of the BD with regards to associated gas production. After 4-5 years, one could observe the effect of the BD through increasing GOR trends.

In connection with the critical gas saturation, the strength of the aquifer represented a large uncertainty. Was the water produced fast enough? Possibilities of water breakthrough? Around 80 000 Sm^3 of water has been produced daily since the start of the BD.

The challenge of sand production required drilling of 80 new wells. Problems with the drilling activities further resulted in a 1-2 years delay in the project. It was not possible to convert oil producers to gas producers, because of the limited sand control. It was also more complicated than expected to convert from perforated liner-completion to open hole gravel pack and sand screens.

The expected levels of subsidence was estimated to 1-1.5 m, which would not result in critical challenges. However gradiometry and a GPS system was positioned at the seabed in order to register movements and to collect data.

Since the wells were perforated in different layers, the production has never continued for a long enough time at the same reservoir zone to reach high levels of H_2S. Seawater without sulphate removal was used for water injection. When sulphate reacts with sulphate-reducing bacteria, the sulphate is reduced from 6+ to 2- and forms H_2S. Subsequently, the operator recommend considering sulphate removal during water injection in order to limit the H_2S production.

Gas Export Possibilities

In 1985, a gas export pipeline via Statpipe to Kårstø was installed on the Statfjord field. Prior to this period the produced gas was mainly injected in the Statfjord field for IOR purposes. As part of the SFLL project, additional investments in gas export capacity was necessary since Kårstø had limited gas-receiving capacity. Hence, Statfjord invested in the Tampen-link to UK Far North Liquids and Gas System (FLAGS) and facilitated the first gas export to UK from the field in 2007. The gas export investments comprised approximately 10% of the project costs.

Today Statfjord is a “must take” gas field exporting mainly to UK and also functioning as a gas export hub for several fields, and are thus used for additional gas export to UK if necessary. In gas sales context, with priority of capacity, this gas is often referred to as “must take” gas. It has in practice first priority for export, because it often causes severe loss of income for companies if this gas do not enter the market.

Decision Criteria for the Blowdown Option

The Statfjord field was not developed with a future BD phase in mind. Therefore, it required huge investments within well engineering and topside modifications. Also, additional gas export capacity was necessary. The first discussions around the BD decision took place in 2002, although the BD was not initiated before 2008. Representatives from Statoil explained how the economic conditions should be controlling the decision, but the technical challenges related to lifetime also naturally affects the decision. The optimum timing was considered as:

“When the gas injection is not beneficial for IOR purposes anymore”

(Stavanger, 2016, March 2)

4.1.2 Oseberg

The Oseberg area is located 140 km north west of Bergen. It consists of 4 fields: Oseberg Main Field, Oseberg Sør, Oseberg East and the subsea satellite field Tune, which is tied back to Oseberg Field Centre.

The following discussion is about the Oseberg Main Field (for short called Oseberg field), which is illustrated in figure 4.3. This oil field comprises an overlying gas-cap.

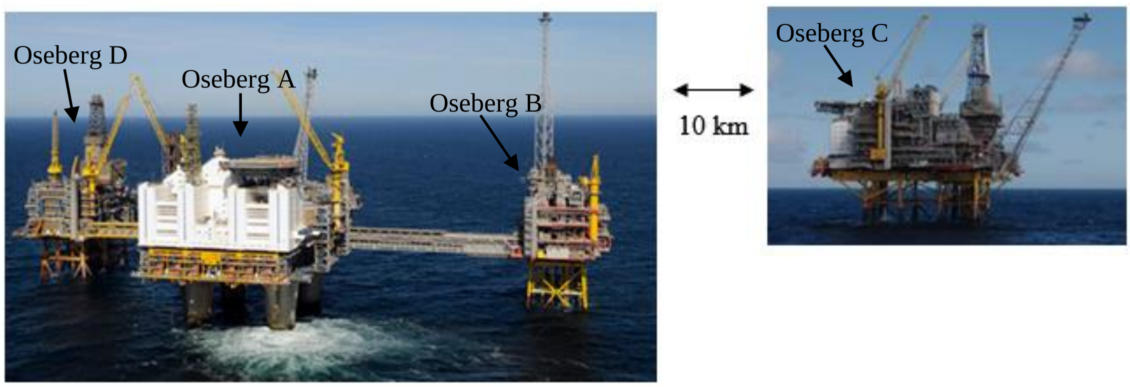

Figure 4.3: Oseberg Main Field including Oseberg Field Centre and Oseberg C (Statoil, 2015)

Oseberg Field Centre (OFC) consists of three facilities: Oseberg A (process and living quarters), Oseberg B (drilling) and Oseberg D (gas process platform). The Field Centre is the gas hub in the area. Oseberg C is an integrated production, drilling and living quarter platform in the northern part of the field. Osebergs' production history is illustrated in figure 4.4.

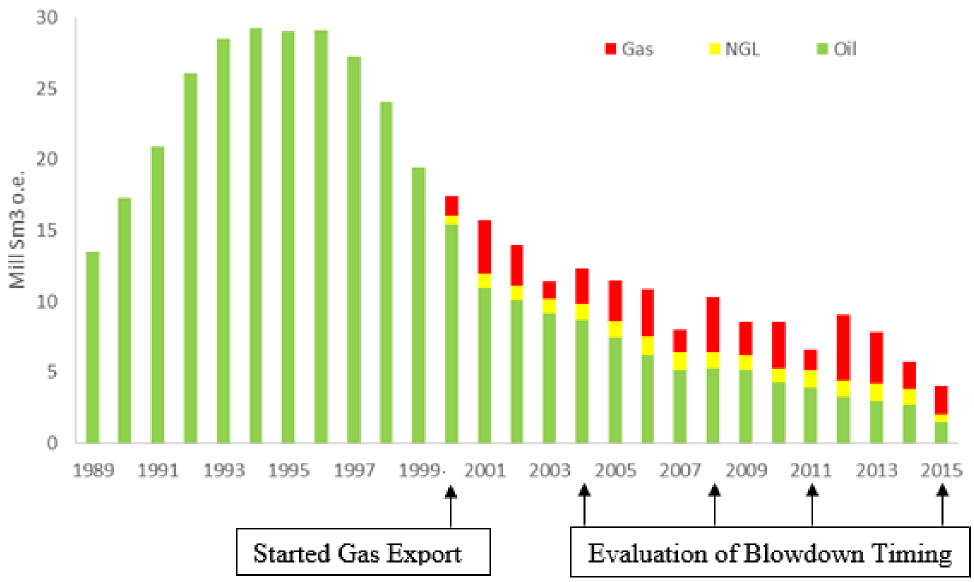

Figure 4.4: Production History Oseberg (Norwegian Petroleum, 2016)

The Oseberg field started gas export in year 2000, and has continued with stable yearly gas export ever since 2003. Initial BD was planned to 2010, but ended up being delayed in order to increase oil recovery. The license partners evaluated the BD timing in 2004, 2008 and 2011, and all the times ended up with prolonging the gas injection. In 2012, Statoil was awarded the NPD’s IOR prize for its work with gas injection in the Oseberg field. A new round of evaluation of BD timing was undertaken in 2014/2015 (ongoing). The expected lifetime of the field is estimated to 2040.

Reservoir Properties and Increased Oil Recovery

The Oseberg field comprises several sandstone reservoirs in the Brent group, including Broom (B), Rannoch (R), Etive (E), Ness (N) and Tarbert (T). The Broom formation is referred to as the Oseberg formation, which is the single most important formation in the field. The reservoirs are located at 2300-2700 m of depth. The total oil recovery factor from the Oseberg formation is likely to be 70-75 %. The Tarbert and Ness reservoirs will have somewhat lower recovery, hence the ultimate oil recovery factor for Oseberg is estimated to 67 %. Gas has been the main method for IOR purposes at Oseberg from the start-up of the field. In the beginning they only used their own associated gas, however in the period 1992-2002 additional gas was imported from the Troll field due to limited amounts available at Oseberg. This is referred to as the Troll Oseberg Gas Injection (TOGI) project.

Technical Challenges

The main technical challenges related to the BD decision have also been identified for Oseberg. The results are presented in figure 4.5, categorized by degree of likelihood on the y-axis and impact on the x-axis.

		Impact				
		Very Low	Low	Medium	High	Very High
Likelihood	Very High					
	High			Sand Production		
	Medium			Aquifer Breakthrough	Drillability	
	Low					
	Very Low				Subsidence	

Figure 4.5: Risk Matrix Oseberg

Critical gas saturation is not a problem, since Oseberg has a large gas-cap it can produce from at once when initiating BD.

The aquifer at Oseberg is not very active. However, there is a risk of increased water production in several oil wells, as they are completed deep in the oil zone. As a compensating measure, it is planned to convert most of the gas injection wells to gas producers in the gas BD phase.

Sand production is a challenge, which may increase as a result of further depressurization. Fortunately, many wells are completed with sand screens. Another common completion method used is oriented perforations, which is perforations shot in such an angle that the risk of sand collapsing into the well is reduced.

In general, subsidence is not a typical problem for sandstone fields. Oseberg is a strong, thick and compact reservoir.

H_2S is not a big issue at Oseberg, as it is mainly a problem for fields using seawater for injection. Some seawater were injected at the Oseberg field at an early stage in the field life. Today this is only pursued in one well in the Statfjord formation.

However, there is an important risk related to drilling through depleted reservoirs, referred to as drillability in figure 4.5. Below a certain reservoir pressure, reservoir drilling may become too difficult. This will affect the decision of how many and for how long new wells can be drilled. Un-drained “pockets” of hydrocarbons located below drained depleted “pockets” may cause challenges.

As a result of reduced reservoir pressure, the processing pressure topside might be lowered as well. Today OFC and Oseberg C have topside inlet pressure of 65 and 70 bar, respectively. By lowering the inlet pressures, the speed of flow will increase and might cause challenges related to erosion of pipes/beds.

Gas Export Possibilities

The gas from Oseberg is transported to the market through Heimdal Gas Centre, therefrom to the Statpipe-system and through the Vesterled pipeline to U.K. Maximum gas processing capacity at the Field Centre is 30 MSm^3/day (dry gas, for export or/and injection). The dry gas capacity is fully utilized, when the yearly export permit is fulfilled, and the rest of the gas goes to injection. In case of BD, no additional infrastructure is required, thus zero investment cost concerning gas export.

Decision Criteria for the Blowdown Option

At Oseberg, the question is not if, but when to blow down the field. From the start of the field development, the operators had in mind that the field would produce large amounts of gas in the future. Therefore, most of the processing equipment and gas export facilities are prepared for a BD phase. As opposed to Statfjord, the BD is not considered as a great investment decision. At Oseberg it is more about cost/benefit for the IOR volumes coming from further gas injection. For simplicity, consider it as two main options: "Early" or "late" BD. Blowing down the field early may lead to early stop of drilling activities, and might result in leaving volumes of oil behind. On the other hand, a late BD means keeping up injection as well as staying above the "critical drilling pressure". This will give the option of drilling for longer periods and thus maximize oil recovery. However, it is not necessarily the optimum economic solution. The representatives from Statoil explained the importance of the economic value of the decision, as well as considering the Norwegian Petroleum Law §4.1 concerning prudent recovery as described below (Bergen, 2016, March 16).

<u>§ 4.1 Prudent Production</u>

«Production of petroleum shall be conducted in such a way that most of the petroleum in place in each individual petroleum deposit, or several petroleum deposits together, are produced. Recovery can take place in accordance with proper technical and healthy economic principles and such that waste of petroleum or reservoir energy is avoided. To achieve this, the licensee shall continuously evaluate production strategy, technical solutions and initiate necessary actions"

(The Petroleum Law)

4.2 Real Options Valuation

A Real Options (RO) valuation was implemented to the purpose of determining the optimum timing decision from a set of possible BD scenarios. The evaluation focused on an example field created based on generic data, inspired by realistic input-parameters from the NCS.

4.2.1 Case Description

The example field is referred to as “field Alpha”. The first oil was produced in year 2000, and the estimated lifetime of the field is to 2052. The reservoir includes both associated gas and free gas in a gas-cap. Future production of oil and gas for the period 2016-2052 were estimated by the use of a material balance model. Table 4.1 lists the most important input-parameters to the material balance model. Oil field units are consistently used during the analysis in order to fit the RO model. The price model is also adapted to the U.S. market, whereas the oil and gas prices are based on West Texas Intermediate (WTI) and Henry Hub (HH), respectively.

Table 4.1: Input-parameters to the Material Balance

Input Parameters	Oil Field Units	SI Units
Number of wells	40	40
Depth of wells	7500 ft	2286 m
Size of production tubing	3.5 inch	0.89 m
Reservoir pressure	4350 psig	300 bar
Solution GOR	1110 scf/stb	198 sm^3/sm^3
Gas-cap gas	2862 Gscf	81 Gsm^3
Oil initially in place	3600 MMstb	572 $MMsm^3$
Max oil rate	50000 stb/day	7949 m^3/day

The oil and gas production profiles are shown in figure 4.6 and 4.7, respectively. The “current time” (time=0) is 2016, which is marked in the figures as the “decision point”. This is the time where the decision of when to blow down the field will be made.

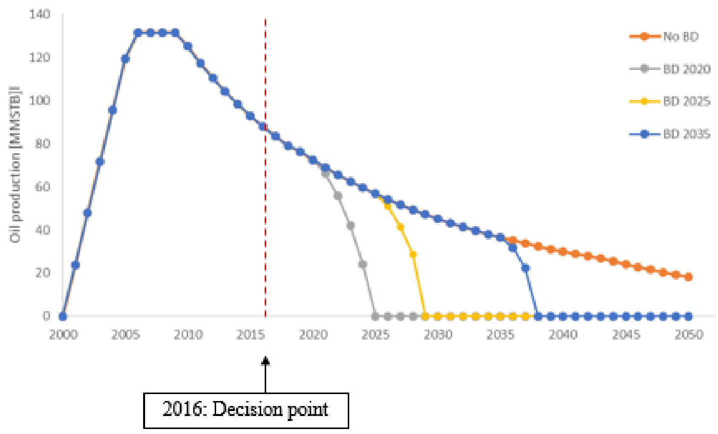

Figure 4.6: Alpha Field Oil Production

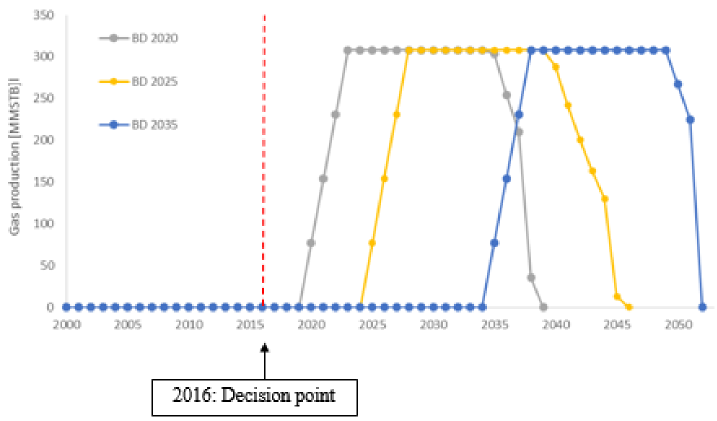

Figure 4.7: Alpha Field Gas Production

Simulation Mechanism

The RO problem is solved using a Monte Carlo Simulation with 10 000 iterations. The simulation runs from year 2016 to 2052. Conversations with Statoil (Bergen, 2016, March 16) revealed that the common industry practice is to evaluate several scenarios (but not a scenario for every possible BD year) in order to determine the optimum timing to initiate BD. Therefore, it was decided to evaluate the following four scenarios for field Alpha: BD at year 2020, 2025, 2035 or no BD.

In addition to the BD option, the field can be abandoned any year between now and 2052. If there is no abandonment recommended by the RO valuation, the abandonment is forced in year 2052. Both the abandonment and BD options are irreversible processes.

The input-parameters to the simulation are listed in table 4.2. The cost of both abandonment and BD are assessed using a PERT distribution, which creates a smooth curve with emphasis on the mode value over the minimum and maximum estimates. The PERT distribution for the initial abandonment case is illustrated in figure 4.8.

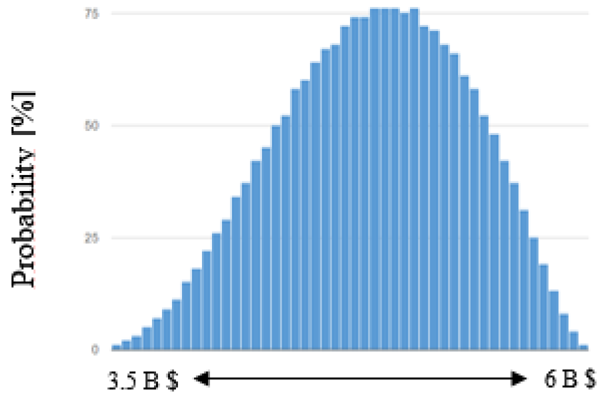

Figure 4.8: PERT Distribution of Initial Abandonment Case

The choice of discount rate is described in the sensitivity analysis. The deterministic fixed and variable costs are generated with support from Philip Thomas. The input-parameters should reflect realistic values for a field at the NCS. However, all fields are different, and so are the BD projects. Hence, it has been challenging to determine sufficient values.

Table 4.2: Simulation Parameters

Simulation Parameters	Value
BD cost	PERT distribution $(500,1000,1500) Million (MM)
Abandonment cost	PERT distribution $(3.5,5,6) Billion
Discount rate	0.06
Fixed cost	$20 MM
Variable cost of oil	$30/oil stb
Variable cost of gas	$0.01/gas MM Btu

Decision Making Algorithm

For every year the optimum decision is recorded in the model and dynamically simulated backwards. The option of BD is limited to year 2020, 2025 and 2035. For those years where BD is permitted, the decision is based on the optimum present value (PV) as shown below:

$$PV_{Optimal,t} = Max[PV_{Continue,t}, PV_{Blowdown,t}, PV_{Abandonment,t}]$$

However, when the BD option is not permitted, the following argument applies:

$$PV_{Optimal,t} = Max[PV_{Continue,t}, PV_{Abandonment,t}]$$

Simulation Output

The RO simulation calculates the value including the real options (BD and abandonment) and then compare it with the value with no options. The difference between the two values equals the real options value, which is a value of the project flexibility. The simulation results are presented in table 4.3.

Table 4.3: Simulation Results

Simulation Results	Value [Billion $]
Value with abandonment and BD options	23.8
Value without options	21.3
Real options value	2.49

A scenario-based decision-making is also reflected in the simulation, referred to as the naïve approach in the methodology chapter. Dynamic learning is not embedded in this model, and the timing of BD decision is made at time=0 with no room for change. The optimum BD time is then found by sequentially evaluating all possible BD times. The results of this approach are presented in table 4.4.

Table 4.4: Scenario-based decision-making

Scenarios	Value [Billion $]
BD at 2020	8.6
BD at 2025	14.4
BD at 2035	16.5
No BD	21.3

The scenario-based approach implies that the optimum decision is "No BD" with an associated value of 21.3 Billion $. This value equals the value calculated during the RO valuation excluding any options. Thus, the scenario-based approach does not create any additional value based on different options.

The results of the RO valuation approach are presented below. Figure 4.9 illustrates the distribution of BD time. The probability distributions are calculated based on the 10 000 simulation iterations. At approximately 41 % of the iterations, the 'No BD' decision is preferred. Figure 4.10 shows the distribution of abandonment time, where approximately 73 % of the iterations recommend abandonment at the end of the field life.

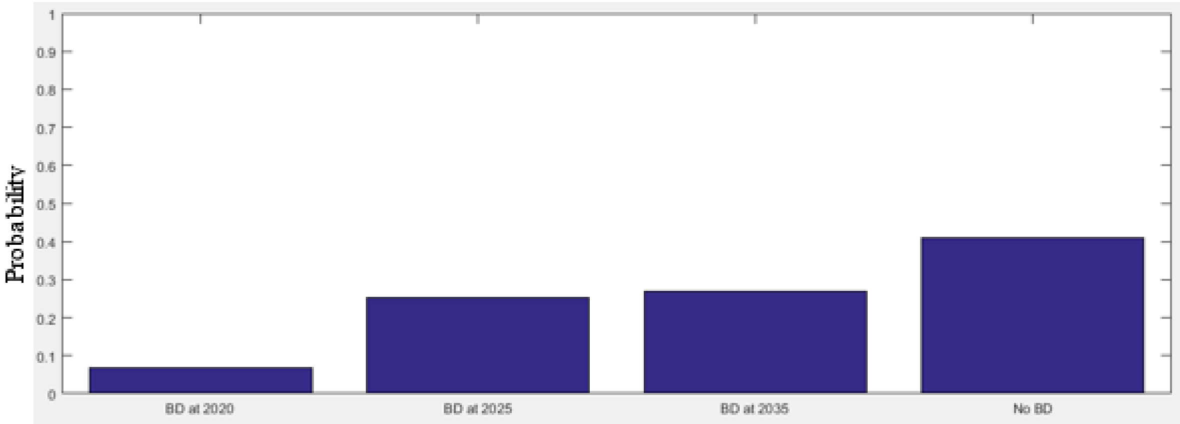

Figure 4.9: Simulation Output - Distribution of BD Time

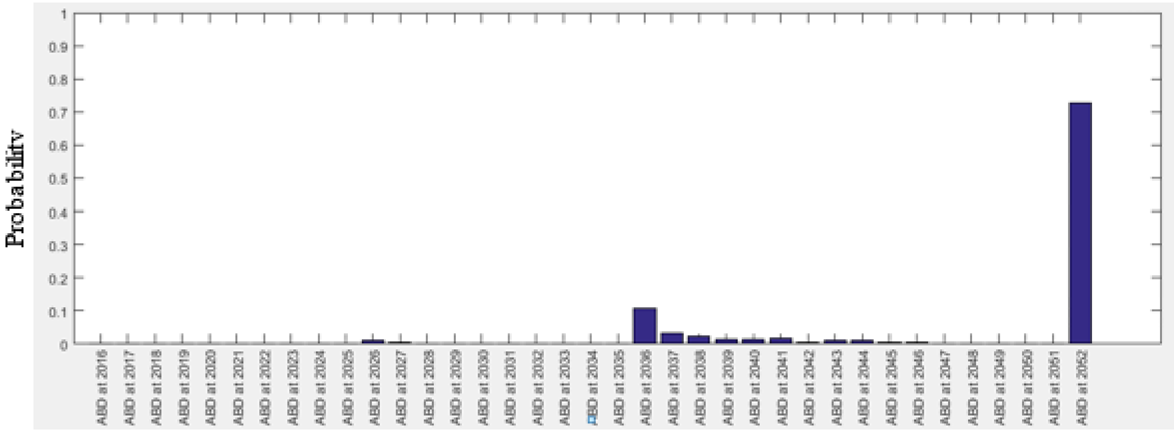

Figure 4.10: Simulation Output - Distribution of Abandonment Time

4.2.2 Sensitivity Analysis

A sensitivity analysis has been conducted based on the field case simulation. The following input-parameters have been investigated: variable cost of oil and gas production, discount rate, cost of abandonment and cost of BD. The goal of the sensitivity analysis is to determine which parameters have the greatest impact on the BD decision.

Variable Cost of Oil Production

The result of changing the variable cost of oil production is presented in table 4.5.

Table 4.5: Sensitivity Analysis – Variable Cost of Oil

Variable Cost of Oil [$/stb]	Value With Options [Billion $]	Real Options Value [Billion $]
20	31.0	2.01
30	23.8	2.49
40	17.6	3.86
50	12.1	6.07

With a variable cost of 20 $/stb, keeping all other parameters constant, the expected value is estimated to 31 Billion $. This is the highest value obtained during the sensitivity analysis. With increasing variable cost of oil, the associated values including options drop significantly. However, the real option values increase with increasing variable cost of oil. Given a variable cost of 50 $/stb, the associated real options value is estimated to 6.70 Billion $. This is the highest real options value obtained during the sensitivity analysis.

The variable cost of oil also affects the BD decision largely. Figure 4.11-4.14 illustrate the distribution of BD time given different variable cost related to oil production. Figure 4.11 shows that approximately 59% of the iterations recommend the ‘No BD’ decision, given a variable cost of 20 $/stb . However, increasing the variable cost to 50 $/stb, as illustrated in figure 4.14, results in an approximately 32% probability of ‘BD at 2020’.

The distribution of abandonment of the field was also influenced by changing the variable cost of oil production. With a value of 20 $/stb, the probability of abandonment at the end of the field life was estimated to 97 %. However, increasing the cost to 50 $/stb gave a probability of abandonment at the end of the field life at 45%. Options of earlier abandonment never exceeded 25 % though, indicating that abandonment in year 2052 is the preferred option independent of changing the variable cost related to oil production.

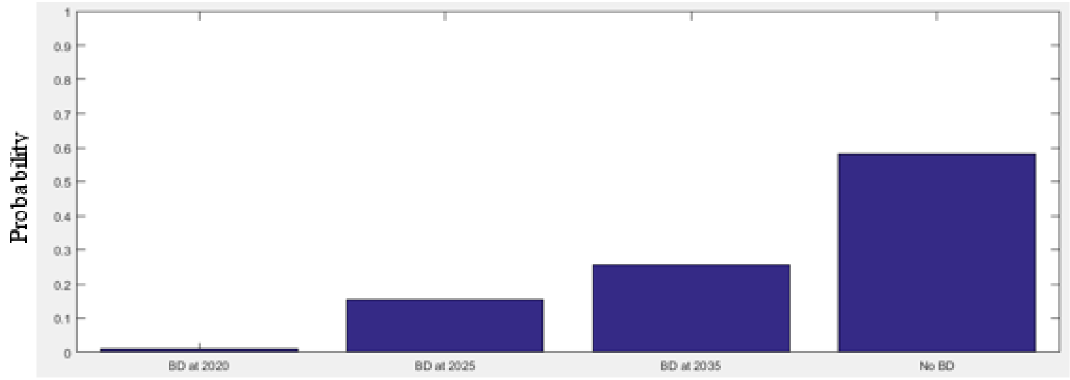

Figure 4.11: Distribution of BD Time given a Variable Cost of 20 $/stb

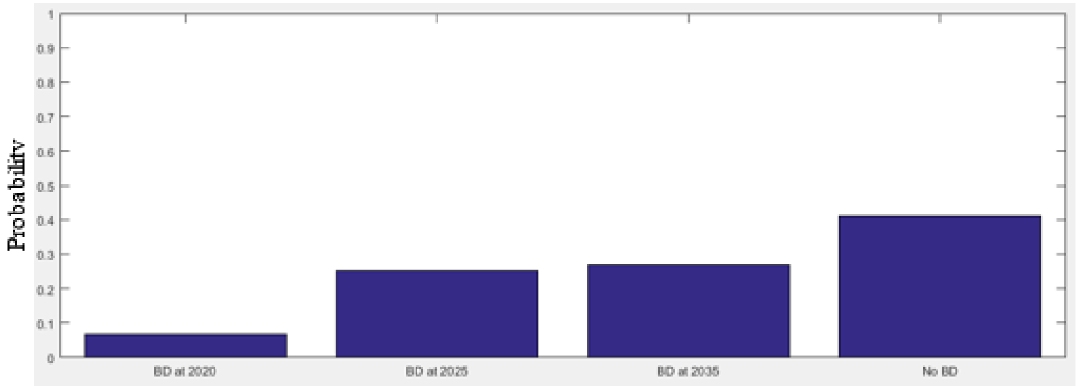

Figure 4.12: Distribution of BD Time given a variable cost of 30 $/stb

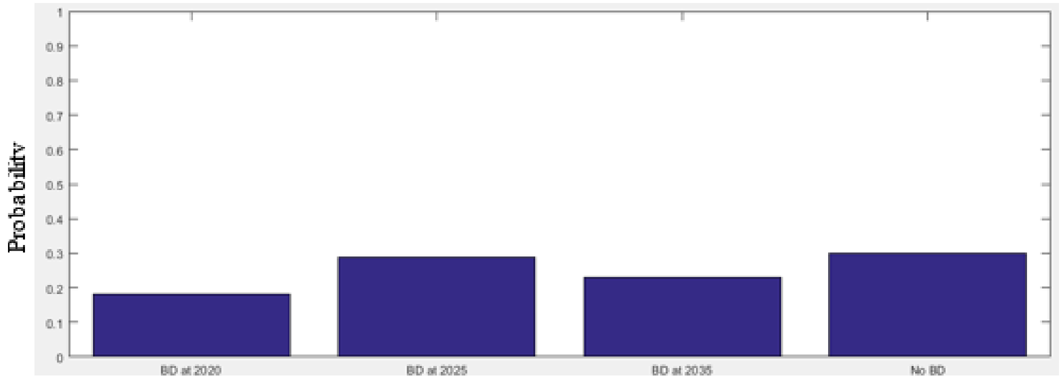

Figure 4.13: Distribution of BD Time given a variable cost of 40 $/stb

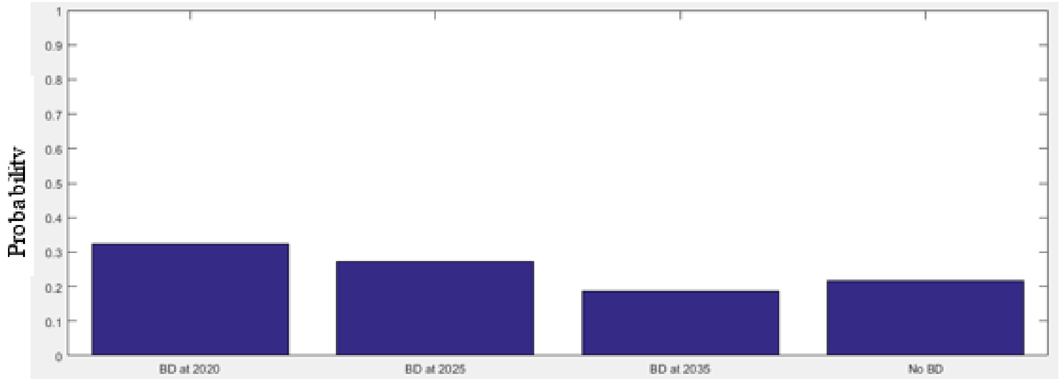

Figure 4.14: Distribution of BD Time given a variable cost of 50 $/stb

Variable Cost of Gas Production

The result of changing the variable cost of gas production is presented in table 4.6.

Table 4.6: Sensitivity Analysis – Variable Cost of Gas

Variable Cost of Gas [$/MM Btu]	Value With Options [Billion $]	Real Options Value [Billion $]
0.00	23.8	2.50
0.01	23.8	2.49
0.10	23.7	2.38
1.00	22.7	1.37

With increasing values of variable cost related to gas production, the associated values including options follow a decreasing trend. The associated real option values also decrease with increasing variable cost of gas production. However, the changes are limited and does not affect the decision concerning the BD or abandonment options compared to the original distributions illustrated in figure 4.9 and 4.10.

Discount Rate

The result of changing the discount rate is presented in table 4.7.

Table 4.7: Sensitivity Analysis - Discount Rate

Discount Rate	Value With Options [Billion $]	Real Options Value [Billion $]
0.04	28.0	2.60
0.05	25.8	2.55
0.06	23.8	2.49
0.07	22.1	2.44
0.08	20.6	2.39
0.09	19.2	2.34

The RO simulation makes use of a risk-free rate. This is because all associated risk should be simulated explicitly in the model. Therefore, it can be argued that a discount rate in the range of 2-8 % could be sufficient. The risk-free rate should include both the market and technical risk. The market risk is for example reflected through uncertainty in oil/gas prices, variable cost of oil/gas and the distributions of abandonment and BD cost. It is believed that the market risk is sufficiently taken into account in the model. However, technical risks such as project execution (delays etc.), production uncertainty and technical challenges are more challenging to implement in the model. Therefore, an interval of 4-9 % was chosen assuming that risks related to technical issues are included to a limited degree. However, the technical challenges that are important to consider when initiating BD have been discussed in chapter 4.1 Qualitative Analysis.

Based on table 4.7, increasing the discount rate results in a decreasing trend for both the associated values with options as well as the real option values. Compared to the initial distribution of BD and abandonment time, the decision is not affected when varying the discount rate from 4-9 %.

Abandonment Cost

The result of changing the cost of abandonment is presented in table 4.8.

Table 4.8: Sensitivity Analysis - Abandonment Cost

Abandonment Cost [Billion $]	Value With Options [Billion $]	Real Options Value [Billion $]
PERT(2,3,4)	23.9	2.39
PERT(3.5,5,6)	23.8	2.49
PERT(6,7,8)	23.7	2.55

Table 4.8 indicates that increasing values of abandonment cost result in decreasing associated values including options. However, the associated real option values are increasing with increasing cost of abandonment. Compared to the initial distribution of BD and abandonment time, varying the abandonment cost distribution has a limited impact on the decisions of BD or abandonment.

Blowdown Cost

The result of changing the cost of BD is presented in table 4.9.

Table 4.9: Sensitivity Analysis - BD Cost

BD Cost [Billion $]	Value With Options [Billion $]	Real Options Value [Billion $]
PERT(0.1,0.5,1)	23.9	2.60
PERT(0.5,1,1.5)	23.8	2.49
PERT(1,1.5,2)	23.7	2.38

Table 4.9 shows that varying the BD cost only affects the associated values including options as well as the real option values to a small degree. Thus varying the BD cost distribution has a limited impact to the BD and abandonment decisions. However, increasing the cost of BD to a sufficient level benefits the ‘No BD’ decision.

5 RESULTS AND DISCUSSION

In this chapter, the key findings based on the qualitative and quantitative analysis are presented as well as discussed.

5.1 Qualitative Results and Discussion

Firstly, the qualitative part in terms of decision criteria, timing and value creation related to any blowdown (BD) project is evaluated.

5.1.1 Decision Criteria

Every petroleum field is different, and therefore the challenges associated with a BD will also widely vary from field to field. There are both technical and economic aspects important to consider when evaluating a BD option. Based on the literature study and interviews, the reservoir condition was found to be the determinative factor for the decision criteria. If the reservoir comprises a gas-cap, the assessment will be very different compared to a reservoir without a gas-cap in place.

Most of the fields considering a BD comprise a gas-cap. However, there are examples of successful BD projects also for fields without presence of a gas-cap. Both Statfjord and Brent are huge oil fields, where most of the gas is associated in the oil phase. Therefore, depressurization in these cases means a significant change in the drainage strategy. The pressure is reduced to below the saturations pressure, in order to boil out the solution gas. A common method for properly reducing the reservoir pressure is to back-produce water. This may however cause water breakthrough. Also when reducing the reservoir pressure, the issue of sand production arises.

A large challenge and uncertainty is associated with the time needed in order to reach the critical gas saturation. At Statfjord for instance, the time needed to reach the critical gas saturation resulted in 1-2 years delay in the BD initiation. In addition, another 1-2 years delay was related to drilling of new wells. This was required, as most of the original wells were completed without sand control.

Oseberg is an example of a field that contains a reservoir with an overlaying gas-cap. The challenges regards to depressurization are more or less the same, excluding critical gas saturation. The decision criteria are very different though. The main reason is that reservoirs comprising a gas-cap usually plan for a BD from the beginning of the field development. Therefore, most of the infrastructure and facilities are installed with this in mind. The decision concerning BD at fields with an overlaying gas-cap is not a question if, but when. Therefore, it is also considered more as moving cost in time, rather than a great investment.

The interviews with Statoil indicated that the following decision criteria were the decisive for fields located at the NCS (Bergen, 2016, March 16):

- *The Petroleum Law §4.1 - Prudent Production*
- *Economic Evaluations – Net Present Value*

The Petroleum Law §4.1 is considered as overall determinant, with respect to sustainable utilization of oil and gas. Apart from the Petroleum Law §4.1, the focus for any operator is certainly to maximize the value of the field through economic evaluations. However, BD evaluations are complex and it might be challenging for the operators to interpret the petroleum legislation. For instance, the Petroleum Law §4.1 does not clearly define the criteria «maximizing petroleum production». Petroleum production includes both oil and gas, but how should the operator prioritize between oil and gas production? Over which period of time should the production be maximized? It could also be hard to understand and determine what "prudent production" is. At what time during the field lifetime is it acceptable to initiate BD? Guidelines to these questions could preferably been worked out. It is also worth mentioning that the authorities might have different interests compared to the operators of oil/gas fields. The authorities have a long-term, socio-economical perspective, thus using a lower discount rate in economic evaluations. Oil companies may often have a more short-term perspective.

Another question to ask is what size of petroleum reserves can be left behind in the reservoirs? Is there different rules that apply to oil versus gas? In case of BD, the focus is certainly on lost oil reserves, as the gas is easier to lift during depressurization. NPD indicated that the amount of oil reserves left behind is dependent on many factors such as geology of the field, existing facilities, required maintenance in the future, estimated lifetime of the field etc. Therefore, produced oil reserves from a field located at the NCS at time of abandonment can vary from 30-70 %.

On one side, the Petroleum Law §4.1 provide the operators and the NPD with a great flexibility when evaluating BD scenarios. However, limited guidelines to the drainage strategy can also result in inconsistent decision-making. A prerequisite to make good decisions is that decision criteria are well defined in such a way that everyone involved in the decision have the same fundament of understanding. The interviews with Statoil and conversations with the NPD indicated a lack of clarity in the decision criteria for operators on the NCS concerning BD.

A common approach for fields at the NCS is however to evaluate the BD option first when oil production is on decline. This is mainly because a switch in oil to gas production can be seen as an irreversible process, thus meaning that converting back to focus on oil production after initiating BD is not beneficial. Depressurization also limits the option of future drilling, as drilling in depleted reservoirs may cause several challenges.

5.1.2 Timing

In the previous section, it is discussed how economic value and sustainable utilization of natural resources lays the foundation for determining the optimum time for initiating BD. Further, the following reservoir technical aspects were found as important elements to consider:

- **Gas Injection:** Expansion of the gas-cap results in gas entering the production wells. The GOR will increase with gas injection over time, and the effect of injecting will become less. This implies a reduced oil gain over time, and that gas injection will become inefficient at a certain point in time. It is also important to bear in mind that gas used for gas injection, and eventually sold at a later stage in time, will cause a loss in net present value for the gas. However, the total budget should be decisive including both oil and gas production.

- **Oil versus Gas Recovery:** A general rule in the oil and gas industry is that most of the injected gas is produced at a later stage in time, then eventually entering the market for sale. However, the gas recovery will never reach 100%. Extended gas injection for IOR can provide a certain loss. The gas can easily be trapped, for example in “pockets” at the shallowest parts of the wells or through contact with aquifer zones. It is also believed that some of the gas migrates from the reservoir. If assuming same reservoir pressure at abandonment for different production scenarios, some gas will be left behind in the reservoir for those scenarios where more oil and water are produced. Some of the gas is also used as fuel for the injection compressors. At the same time, as the reservoir pressures decline, pressure support in terms of gas injection is often required to maintain oil production. Therefore, the operator should properly evaluate oil versus gas recovery as well as economics considering different scenarios.

- **Drilling in Depleted Reservoirs:** A factor that effects the vast majority of oil/gas fields, is that drilling of new wells will gradually become more technically challenging. Eventually it is not safe to drill in depleted reservoirs. Many oil/gas fields drill "infill wells" for IOR purposes after the initial drilling phase. The BD timing will then affect when the drilling must be terminated. A decline in reservoir pressure will also make production of oil unprofitable at a certain point in time. This is due to reduced lifting capacity in the wells.

- **Reservoir Communication:** A consequence of BD is that the pressure reduction might affect local reservoir zones, often through aquifer communication. This can cause challenges concerning drilling and production activities. Pressure reductions might also affect other oil/gas fields regionally. The field that initiate BD activities can be imposed to come up with a monitoring plan including regularly reporting of reservoir pressures. Any compensatory actions, such as additional injection or drilling, are however up to the neighboring fields to consider.

5.1.3 Value Creation

Value creation is often what gives the drive to initiate BD projects. The value of a field will possibly increase by planning for strategic production as well as implementing smart technical solutions and reduce cost within safety limits. The following key points were identified as typical examples of what can add value during a BD phase:

- **Operational Flexibility:** For fields initiating BD it may be a need to replace the gas compressors with higher capacity export compressors. Compressors that have been used for injection, may be rebuilt for gas export. Thus, it is customary to make a cost/benefit assessment. It might be beneficial to retain parts of the injection capacity as operational flexibility. If gas export is prevented in periods, the field can keep injecting the gas, and earn income of additional oil produced. However, this also requires operations and maintenance of the injection wells, which also have an alternative value as gas producers.

- **Investments:** The pressures in the wells gradually decline, and it might be necessary to reduce the process pressures on the platform. This could require modification of compressors and investments of additional compressor capacity. The timing of initiating BD affects the timing of when it is optimum to invest in "low pressure modifications". Such costs and associated volumes produced are often included in the economic analysis of the BD scenarios.

- **Flexible Gas Supply:** Large gas fields can act as flexible suppliers of gas, and are therefore particularly important for Gassco and the shippers. Usually they have gas injection and gas export capacity installed simultaneously. These fields are important for modulating a stable gas export from the NCS. If a field has problems with gas supply, another field may substitute for the shortfall.

  The flexible gas supply at such fields (prior to full BD) is also utilized to maximize the value of the sold gas. It is beneficial to sell most of the gas during the winter, with the highest gas prices. The longer the period of flexible gas sale lasts, the greater part of the overall gas volumes can be sold at winter price. This can be seen as a premium price, which adds value to the economic analysis for different BD scenarios. However, when initiating BD, the goal is certainly to exploit the full gas export opportunities throughout the year, thus much of the gas is certainly sold at summer prices.

- **Real Options:** The value of future possibilities are important to include in the economic analysis, when evaluating different BD scenarios. Representatives from Statoil indicated that possible tie-ins of other discoveries could improve the option value of the decision.

5.2 *Quantitative Results and Discussion*

In this chapter, the key findings based on the field case analysis is presented and discussed.

5.2.1 Field Case

The field case analysis is discussed in terms of the Real Options (RO) valuation model, simulation output and sensitivity analysis conducted.

Real Options Valuation

A simple material balance model was applied in order to predict future production of oil and gas. In this thesis, the goal was not to estimate the correct economic value resulting from a decision, but to rank alternatives based on the decision-makers' decision criteria and thus provide a basis for high-quality decision-making. Therefore, a material balance model was believed to be sufficient considering the goal of this thesis. For further work, it could be interesting to establish a cooperation with one or more oil/gas companies in order to investigate the value of implementing a more complex reservoir model, such as Eclipse, to the RO valuation.

The selected range of discount rate can be discussed. The RO simulation makes use of a risk-free rate, since all associated risk should be simulated explicitly in the model. As discussed in 4.2.2 Sensitivity Analysis, it is believed that the market risk is sufficiently taken into account. However, technical risks such as project execution, production uncertainty and technical challenges were challenging to implement in the model, and thus were only included in terms of cost related to BD and abandonment of the field. Therefore, the technical challenges have been discussed in parallel as part of the qualitative analysis. A further investigation on the possible effects of the technical challenges such as critical gas saturation, sand production, aquifer breakthrough etc. is recommended. Also, the project execution should be considered in terms of possible delays or additional costs to any BD project.

As pointed out in chapter 5.1.1 Decision Criteria, the qualitative investigation indicated a lack of clarity in the decision criteria for operators on the NCS concerning BD. If there existed guidelines to the "prudent production" term, such as minimum and maximum oil/gas production required prior to initiating BD, these limits could be implemented to the RO simulation.

Simulation Output

The RO simulation calculates both the value including options (BD and abandonment) and then compare it with the value with no options. The difference between the two values equals the RO value, which is a value of the project flexibility. Maximized values of both the expected value including options as well as the RO value are preferred. Therefore, these values have been in focus during the analysis. The RO simulation results are presented in table 5.1. Distribution of BD and abandonment time are shown in figure 4.9 and 4.10, respectively.

Table 5.1: Simulation Results

Simulation Results	Value [Billion $]
Value with abandonment and BD options	23.8
Value without options	21.3
Real options value	2.49

As shown in figure 4.10, approximately 73% of the iterations recommended abandonment at the end of the field life. Figure 5.1 illustrates the trend of the preferred decision concerning BD. Approximately 41% of the iterations resulted in the 'No BD' decision. Apart from that, the graph shows that the BD is likely to be delayed during the field life.

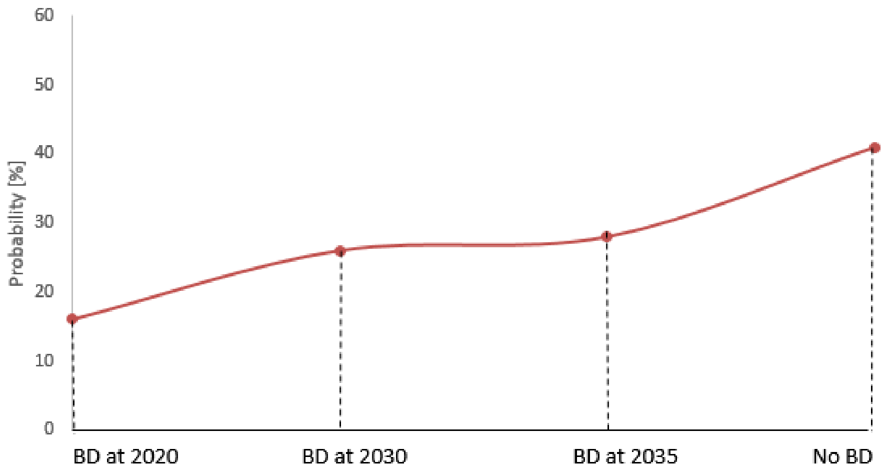

Figure 5.1: Simulation Output - Distribution of BD Time

Conversations with Statoil (Bergen, 2016, March 16) revealed that the common industry practice is to evaluate several scenarios in order to determine the optimum timing to initiate BD. Therefore, it was decided to only consider four BD scenarios. However, excluding possible options limits the simulation. In reality, one has the option to BD the field every year. The abandonment options were implemented and considered for every operating year. Including BD options for every year in the period 2016-2052 would therefore benefit the RO value and provide a more realistic picture.

Sensitivity Analysis

A set of sensitivity analysis were conducted based on the field case simulation. The following input-parameters were considered: variable cost of oil and gas production, discount rate, cost of abandonment and BD. Figure 5.2 illustrates the effect of varying the input-parameters to the E[NPV]. The ranges considered for each input-parameter can certainly be questioned, and possibly be improved with support from industry experience. However, based on the ranges assumed, one can observe that the variable cost of oil is the parameter which affects the E[NPV] the most. With a variable cost of 20 $/stb, the estimated value including options is 31 Billion $. However, increasing the cost to 50 $/stb results in a 61 % decrease in the estimated value to 12.1 Billion $. The highest RO value of 6.07 Billion $ was also obtained with a variable cost of 50 $/stb. This implies a great flexibility given the options of abandonment and BD. Excluding the options in this case would result in an E[NPV] of 6.03 Billion $, which is a significant low project value compared to the other estimated project values during the sensitivity analysis.

A reduction in the variable cost of gas to 0 $/MM Btu has a limited impact to the estimated project value including options. Increasing the variable cost results in a slight decrease in the expected value with options. However, the changes are limited and implies that the variable cost of gas is less important to the decision compared to the variable cost of oil. The cost of abandonment and BD are considered as minor compared to the cost related to production.

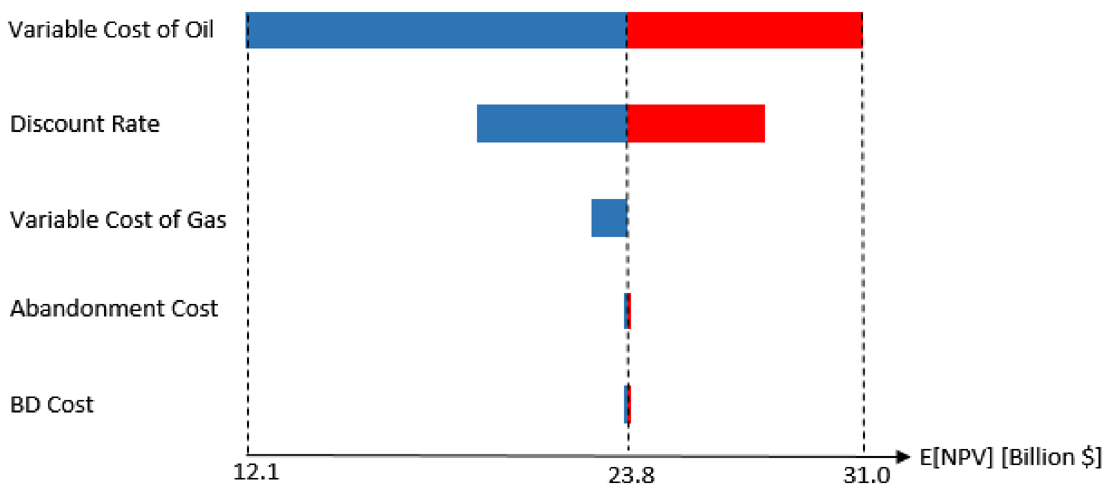

Figure 5.2: Sensitivity Analysis – Effect of Varying the Input-parameters to the E[NPV]

The variable cost of oil was the only parameter affecting the decision concerning BD. Figure 5.3 illustrates how different decisions are preferred with varying cost of oil production. The 'No BD' decision is recommended with a probability of 59 % given a variable cost of 20 $/stb. However, increasing the variable cost to 50 $/stb results in a 32 % probability of 'BD in 2020'. This large fluctuation is greatly affecting the decision, but also the project value. Therefore, it is recommended to properly evaluate and predict future estimates of this parameter when evaluating BD scenarios.

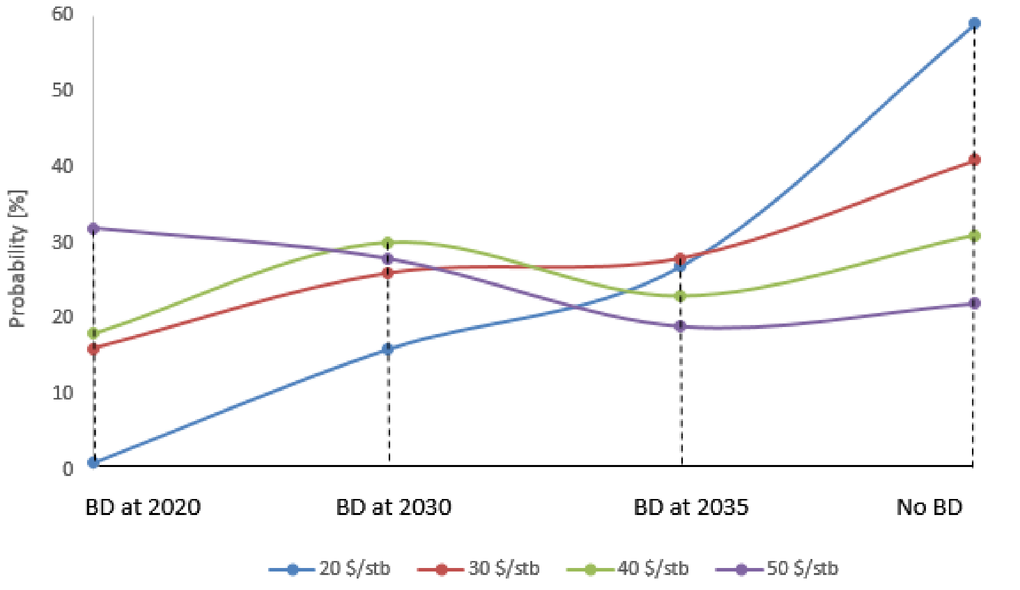

Figure 5.3: Sensitivity Analysis - Variable Cost of Oil

6 CONCLUSION

This thesis provides insight into the decision process concerning blowdown (BD) for fields located at the NCS, including uncertainties related to timing and value creation. A field case study was conducted using a Real Options (RO) model to evaluate the optimum timing for BD as well as sensitivity analysis associated with the decision. The goal of the thesis was not to estimate the correct economic value, but to rank alternatives based on decision-maker's decision criteria and thus provide a basis for high-quality decision-making.

The reservoir condition was found to be the determinative factor for the decision criteria concerning BD. Reservoirs with an overlying gas-cap usually plan for a BD from the beginning of the field development, and therefore the project is considered more as moving cost in time rather than a great investment such as for fields without presence of a gas-cap. Representatives from Statoil indicated that the following were the overall decisive criteria for fields located on the NCS: The Petroleum Law §4.1 and economic evaluations. However, BD evaluations are complex and it might be challenging for the operators to interpret the petroleum legislation. Hence, the qualitative analysis indicated a lack of clarity in the decision criteria. On one side, the operators and authorities are served with a great flexibility, however limited guidelines may result in inconsistent decision-making.

Reservoir technical challenges such as gas injection efficiency, oil versus gas recovery, drillability and reservoir communication were identified as important factors to consider when evaluating the optimum timing of initiating BD. Operational flexibility, investments, flexible gas supply and real options were also discussed as crucial factors which could possibly add value to any BD project.

The RO model is believed to sufficiently account for market risk. However, technical risks such as project execution, production uncertainty and technical challenges are only included to a limited degree. The simulation resulted in an estimated value (including the abandonment and BD options) and real options value of 23.80 and 2.49 Billion $, respectively. As a result of the sensitivity analysis, the variable cost of oil was found as the only parameter that significantly affected the BD decision. The highest value including options of 31 Billion $ was achieved with a variable cost of 20 $/stb. At this value, the 'No BD' decision was recommended with a probability of 59 %. However, increasing the variable cost of oil to 50 $/stb resulted in a probability around 32 % of ‘BD in 2020’. Therefore, it is recommended to properly evaluate and predict future estimates of this parameter when evaluating BD scenarios.

7 FUTURE WORK

Based on the results of this thesis there are still some questions to be answered. Below I have summarized my recommendations for future work related to the BD decision of oil fields with gas injection.

Firstly, the decision of optimum BD timing could be improved through a further examination of the reservoir behavior. As an example the gas injection efficiency in terms of GOR trends could be investigated. What is the optimal GOR when initiating BD? At which GOR turns the gas injection inefficient? Hence, fields that have already initiated BD are comparable with fields that plan for a BD in the near future.

The results of the qualitative analysis indicated a lack of clarity in the decision criteria concerning BD for operators on the NCS. Therefore, it is recommended to perform a study in cooperation with the NPD and oil/gas industry in order to identify the need of guidelines. How should the operator prioritize between oil and gas production? At what time during the field lifetime is it acceptable to initiate BD?

To obtain a more realistic and precise RO valuation, the model should be expanded including all possible BD options. It would also be beneficial to establish a cooperation with one or more oil/gas companies in order to investigate the efficiency of implementing a more complex reservoir model, such as Eclipse, to the RO valuation model. The estimated cost parameters could also be improved with support from the industry providing realistic numbers.

Technical risks such as project execution, production uncertainty and technical challenges were only included to a limited degree in the model. A further investigation on the possible effects of the technical challenges such as critical gas saturation, sand production, aquifer breakthrough etc. is necessary. Also, the project execution should be considered in terms of possible delays or additional costs to any BD project. Further, one can work out uncertainty distributions which can be implemented to the model, and probably improve the RO valuation.

8 REFERENCES

American Association of Petroleum Geologists (AAPG) Wiki. (2016, February 24). *Reservoir drive mechanisms*. From: http://wiki.aapg.org/Reservoir_drive_mechanisms

Beecroft, W., Mani, V., Wood, A., & Rusinek, I. (1999). Evaluation of Depressurization, Miller Field, North Sea. *SPE 56692.* Society of Petroleum Engineers.

Bezruchenko, V. (2015, April 3). *Finance Magnates*. From: http://www.financemagnates.com/forex/analysis/understanding-natural-gas-market-part-i-the-basics/

Boge, R., Lien, S., Gjesdal.A, & Hansen, A. (2005). Turning a North Sea Oil Giant Into A Gas Field - Depressurization of the Statfjord Field. *SPE 96403.* Society of Petroleum Engineers.

Braithwaite, C., & Schulte, W. (1992). Transforming the Future of the Brent Field: Depressurisation - The Next Development Phase. *SPE 25026.* Society of Petroleum Engineers.

Bratvold, R. B., & Thomas, P. (2015). A Real Options Approach to the Gas Blowdown Decision. *SPE-174868.* Society of Petroleum Engineers.

Bringedal, B. (2003). *Master's Thesis - Valuation of Gas Storage.* Norwegian University of Science and Technology.

Christiansen, S. (1997). Challenges in the Brent Field: Implementation of Depressurization. *SPE 38469.* Society of Petroleum Engineers.

Dahl, H. J. (2015). *Bringing Norwegian gas to Europe - Historic perspectives and main roles.* Gassco.

Danesh, A. (1998). From: Center for Energy Economics: http://www.beg.utexas.edu/energyecon/lng/LNG_introduction_07.php

Eclipse Energy Group. (2013). *Development of an upstream gas market at a hub on the Norwegian pipeline system.* Eclipse Energy Group.

Gassco. (2016, January 11). *Leveranserekord i 2015*. From: Gassco https://www.gassco.no/media/nyheter/Leveranserekord-i-2015/

Gassco. (2015, March 25). *Bringing Norwegian Gas to Europe.*

Heather, P. (2012). Continental European Gas Hubs: Are they fit for purpose? *NG 63.* Oxford Institute for Energy Studies.

Hem, Ø. D., Svendsen, A., Fleten, S.-E., & Gunnerud, V. (2011). The Option to Switch from Oil to Natural Gas in Active Offshore Petroleum Fields.

Ligthelm, D., & G.C.A.M, R. (1997). Critical Gas Saturation During Depressurization and its Importance in the Brent Field. *SPE 38475.* Society of Petroleum Engineers.

Matre, B., & Helliesen, G. (1998). *Produksjon under metningstrykk.* The Norwegian Petroleum Directorate.

Natural Gas. (2013, September 20). From: Natural Gas: http://naturalgas.org/overview/background/

Norwegian Petroleum (2016, March 31). From: http://www.norskpetroleum.no/en/facts/production/

Norwegian Petroleum Directorate. (2005). *Petroleumsressursene på norsk sokkel.*

Norwegian Petroleum Directorate. (2009, September 23). *Store gassressurser opp i røyk.* From: http://www.npd.no/no/Tema/Miljo/Temaartikler/Store-gassressurser-opp-i-royk

Norwegian Petroleum Directorate. (2014, November 24). *The Norwegian Petroleum Directorate*. From: Store mengder olje fra gassinjeksjon: http://www.npd.no/no/tema/okt-utvinning/temaartikler/store-mengder-olje-fra-gassinjeksjon/

Norwegian Petroleum Directorate. (2016). Interviews.

Norwegian Petroleum Directorate. (2016, February 24). From: Norsk Petroleum: http://www.norskpetroleum.no/produksjon/produksjon-av-olje-og-gass/

Perez, L. (2009). *Optimal Operation of a LNG Process.* Norwegian University of Science.

Reservoir Engineering Online. (2014, December 14). From: Gas Cap Blowdown: http://www.reservoir.solutions/2014/12/gas-cap-blowdown-gcbd.html

Shell. (1998). Challenges in the Brent Field: implementing Depressurization. JPT.

Statoil. (2015, December 01). From: http://www.statoil.com/en/ouroperations/explorationprod/ncs/oseberg/Pages/default

SPE International. (2016, January 19). *PetroWiki*. From http://petrowiki.org/Relative_permeability#Critical_gas_saturation

Stava, T. O. (2015). *Kollsnes prosessanlegg.* Gassco.

The Petroleum Law. From: LOVDATA: https://lovdata.no/dokument/NL/lov/1996-11-29-72